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Capital Power
RESPONSIBLE ENERGY FOR TOMORROW

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Capital Power reports solid second quarter 2019 results and announces a 7.3% dividend increase for its common shares

Company is on track to achieve results at the top end of annual financial target range

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

Second Quarter Highlights

- Increased the common share dividend by 7.3% to $1.92 per year representing the sixth consecutive annual increase
- Acquired the Goreway facility, an 875-megawatt natural gas facility in Ontario that is contracted until 2029
- Raised $625 million in gross proceeds from a private placement debt financing and common and preferred share offerings
- Accelerated plans to increase natural gas capability at the Genesee facility and transform Genesee 2 and 1 to 100% dual-fuel optionality by mid-2020 and spring 2021, respectively
- Increased equity interest in C2CNT that is focused on transforming captured carbon into leading-edge products
- Net cash flows from operating activities were 5% higher and adjusted funds from operations were 12% higher than the comparable quarter in 2018

"I am pleased to announce that the Board of Directors has approved a 7.3% per common share dividend increase effective with the third quarter 2019 dividend payment, which is consistent with our 7% annual dividend growth guidance to 2021," said Brian Vaasjo, President and CEO of Capital Power. "Our dividend growth is supported by adjusted funds from operations (AFFO) per share growth and our payout ratio target of 45% to 55%."

Net cash flows from operating activities were $114 million in the second quarter of 2019 compared with $109 million in the second quarter of 2018. Adjusted funds from operations were $85 million in the second quarter of 2019, compared to $76 million in the second quarter of 2018.

Net income attributable to shareholders in the second quarter of 2019 was $108 million and basic earnings per share was $0.93 per share, compared with net income attributable to shareholders of $68 million, and basic earnings per share of $0.55, in the comparable period of 2018. Normalized earnings attributable to common shareholders in the second quarter of 2019, after adjusting for non-recurring items and fair value adjustments, were $15 million or $0.14 per share compared with $21 million or $0.20 per share in the second quarter of 2018.

Net cash flows from operating activities were $400 million for the six months ended June 30, 2019 compared with $252 million for the six months ended June 30, 2018. Adjusted funds from operations were $202 million for the six months of 2019, compared to $161 million in the comparable six month period last year.

For the six months ended June 30, 2019, net income attributable to shareholders was $169 million and basic earnings per share was $1.42 per share compared with $109 million and $0.85 per share for the six months ended June 30, 2018. For the six months ended June 30, 2019, normalized earnings attributable to common shareholders were $45 million, or $0.44 per share, compared with $50 million, or $0.48 per share in the first six months of 2018.

"One of the highlights in the second quarter was the acquisition of Goreway Power Station, a contracted natural gas facility operating in the Ontario power market", said Mr. Vaasjo. "The Goreway facility is an excellent strategic fit to our growth plans given its size, excellent operating history, location, and remaining contract term to 2029. Combined with our other Ontario natural gas assets, we have nearly 1,200 megawatts of capacity that will provide operating and market synergies over time. With its strategic location in the Greater Toronto Area load centre and the flexibility it can provide, the Goreway facility is an important asset in Ontario's electric system with a high probability of re-contracting."

"In June, we announced plans to accelerate natural gas capability at the Genesee facility. Genesee 2 is expected to have 100% dual-fuel capability to burn up to 100% natural gas or coal, or a mix of the two by mid-2020 followed by Genesee 1 in the spring of 2021. Having the dual-fuel flexibility at Genesee allows us to reduce emissions while also optimizing the fuel mix to maximize economic returns. Implementation of the dual-fuel capability will complete the first step of our sustainability strategy, the next few of which will include: constructing all new natural gas generation units to be carbon capture and/or hydrogen-ready; reducing our CO_2 emissions by 10% and our emission intensity by 65%, by 2030 from 2005 levels in spite of increasing our generation by 145%; and continuing to invest in carbon capture and utilization technology such as C2CNT to eventually decarbonize our natural gas fleet," stated Mr. Vaasjo.

Our 2018 Corporate Sustainability Report, *Responsible Energy for Tomorrow*, was released today and outlines our sustainability targets, highlights our company-wide environmental, economic, social and safety performance and describes our management approach to delivering low-carbon energy.

"Capital Power's financial results in the second quarter of 2019 were in line with management's expectations," said Mr. Vaasjo. "We had scheduled maintenance outages at Genesee 1, Shepard Energy Centre, Clover Bar Energy Centre, and numerous U.S. facilities in the second quarter that contributed to an average facility availability of 92%. The Company generated adjusted funds from operations (AFFO) of $85 million in the second quarter and $202 million in the first half of 2019. Based on our forecast for the remainder of the year, we are on track to achieve AFFO at the top end of the $485 million to $535 million annual guidance range for 2019."

Operational and Financial Highlights [1] (unaudited)	**Three months ended June 30**		**Six months ended June 30**	
(millions of dollars except per share and operational amounts)	**2019**	**2018**	**2019**	**2018**
Electricity generation (Gigawatt hours)	5,500	4,584	11,282	9,610
Generation facility availability	92%	93%	94%	95%
Revenues and other income [3]	$ 366	$ 369	$ 763	$ 682
Adjusted EBITDA [2, 3]	$ 191	$ 207	$ 393	$ 386
Net income [3, 4, 5]	$ 106	$ 66	$ 166	$ 105
Net income attributable to shareholders of the Company [3]	$ 108	$ 68	$ 169	$ 109
Basic earnings per share [3]	$ 0.93	$ 0.55	$ 1.42	$ 0.85
Diluted earnings per share [3]	$ 0.92	$ 0.55	$ 1.41	$ 0.85
Normalized earnings attributable to common shareholders [2,3]	$ 15	$ 21	$ 45	$ 50
Normalized earnings per share [2, 3]	$ 0.14	$ 0.20	$ 0.44	$ 0.48
Net cash flows from operating activities	$ 114	$ 109	$ 400	$ 252
Adjusted funds from operations [2]	$ 85	$ 76	$ 202	$ 161
Adjusted funds from operations per share [2]	$ 0.82	$ 0.74	$ 1.97	$ 1.55
Purchase of property, plant and equipment and other assets	$ 279	$ 66	$ 330	$ 106
Dividends per common share, declared	$ 0.4475	$ 0.4175	$ 0.8950	$ 0.8350

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 six months ended June 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 June 30, 2019 and 2018 of $122 million and $83 million respectively, and for the six months ended June 30, 2019 and 2018 of $220 million and $167 million respectively. Forecasted depreciation and amortization for the three months ended September 30, 2019 and December 31, 2019 are $137 million and $119 million respectively.

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

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 preliminary 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.

Subsequent Event

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 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.

Analyst conference call and webcast

Capital Power will be hosting a conference call with analysts on July 29, 2019 at 9:00 a.m. MDT (11:00 a.m. EDT) to discuss the second 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							
	Jun 30 2019	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**
Revenues and other income [2]	366	397	340	395	369	313	267	352
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(134)	(167)	(233)	(261)	(152)	(153)	(125)	(198)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	(48)	(34)	53	35	(22)	1	18	3
Adjusted EBITDA from joint ventures [1]	7	6	11	10	12	18	18	10
Adjusted EBITDA	**191**	**202**	**171**	**179**	**207**	**179**	**178**	**167**
Depreciation and amortization [2]	(122)	(98)	(85)	(83)	(83)	(84)	(80)	(83)
Unrealized changes in fair value of commodity derivatives and emission credits	48	34	(53)	(35)	22	(1)	(18)	(3)
Impairments	-	-	-	-	-	-	-	(83)
Gain on disposal of joint venture	-	-	159	-	-	-	-	-
Foreign exchange (loss) gain	-	(4)	6	(2)	3	3	(4)	21
Net finance expense	(37)	(36)	(33)	(28)	(29)	(33)	(32)	(31)
Finance expense and depreciation expense from joint ventures [1]	(7)	(8)	(10)	(7)	(8)	(7)	(13)	(6)
Income tax recovery (expense) [2]	33	(30)	(19)	(7)	(46)	(18)	(45)	9
Net income (loss)	**106**	**60**	**136**	**17**	**66**	**39**	**(14)**	**(9)**
Net income (loss) attributable to:								
Non-controlling interests	(2)	(1)	(2)	(1)	(2)	(2)	(3)	(2)
Shareholders of the Company [2]	108	61	138	18	68	41	(11)	(7)
Net income (loss)	**106**	**60**	**136**	**17**	**66**	**39**	**(14)**	**(9)**

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 June 30**		**Six months ended June 30**	
	2019	**2018**	**2019**	**2018**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**114**	**109**	**400**	**252**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	26	25	47	50
Realized loss on settlement of interest rate derivatives	13	-	19	-
Change in fair value of derivatives reflected as cash settlement	(30)	(11)	(37)	(20)
Distributions received from joint ventures	(3)	(6)	(6)	(19)
Miscellaneous financing charges paid [1]	2	1	3	3
Income taxes paid	-	-	2	1
Change in non-cash operating working capital	34	10	(113)	(6)
	42	19	(85)	9
Net finance expense [2]	(29)	(24)	(57)	(49)
Current income tax expense [3]	(3)	(5)	(1)	(9)
Sustaining capital expenditures [4]	(31)	(20)	(40)	(41)
Preferred share dividends paid	(12)	(10)	(23)	(20)
Remove tax equity interests' respective shares of adjusted funds from operations	(1)	(2)	(2)	(4)
Adjusted funds from operations from joint ventures	5	9	10	23
Adjusted funds from operations	**85**	**76**	**202**	**161**
Weighted average number of common shares outstanding (millions)	**103.6**	**103.1**	**102.7**	**103.6**
Adjusted funds from operations per share ($)	**0.82**	**0.74**	**1.97**	**1.55**

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 $1 million and $3 million for the three and six months ended June 30, 2019, respectively, compared with $3 million and $5 million for the three and six months ended June 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							
	Jun 30 2019	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**
Basic earnings (loss) per share ($)[2]	**0.93**	**0.49**	**1.24**	**0.08**	**0.55**	**0.30**	**(0.21)**	**(0.15)**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss) [2]	**108**	**61**	**138**	**18**	**68**	**41**	**(11)**	**(7)**
Preferred share dividends including Part VI.1 tax	(12)	(11)	(11)	(10)	(11)	(10)	(11)	(9)
Earnings (loss) attributable to common shareholders [2]	96	50	127	8	57	31	(22)	(16)
Unrealized changes in fair value of derivatives [1]	(30)	(20)	35	26	(19)	25	14	(31)
Alberta tax rate change	(51)	-	-	-	-	-	-	-
Gain on disposal of joint venture	-	-	(134)	-	-	-	-	-
Non-cash tax equity adjustment	-	-	-	-	(15)	-	-	-
Realized foreign exchange (gain) loss on settlement of foreign currency derivative instruments	-	-	-	-	-	(29)	-	12
Asset held for sale accounting treatment of K2 Wind	-	-	3	-	-	-	-	-
Income tax adjustment	-	-	-	-	(2)	2	-	-
Impairments	-	-	-	-	-	-	-	53
Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt	-	-	-	-	-	-	(1)	44
Realized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	-	-	-	-	-	(1)	(35)
Provision for Line Loss Rule Proceeding	-	-	-	-	-	-	7	-
U.S. tax reform rate decrease	-	-	-	-	-	-	31	-
Success fee received related to development project	-	-	-	-	-	-	(3)	-
Release of tax liability on foreign domiciled investment	-	-	-	-	-	-	(1)	-
Normalized earnings attributable to common shareholders [2]	**15**	**30**	**31**	**34**	**21**	**29**	**24**	**27**
Weighted average number of common shares outstanding (millions)	103.6	101.8	102.3	102.4	103.1	104.2	104.3	104.1
Normalized earnings per share ($)[2]	**0.14**	**0.29**	**0.30**	**0.33**	**0.20**	**0.28**	**0.23**	**0.26**

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 and AFFO per share increases, related to the acquisition of Goreway, (iii) expected impacts on adjusted EBITDA and AFFO from Arlington Valley driven by the HRCO signed in the year, (iv) expected AFFO performance compared to guidance for 2019 and (v) 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, (vii) ability to realize the anticipated benefits of the Goreway acquisition, (viii) limitations inherent in the Company's review of acquired assets, and (ix) 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 July 26, 2019, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the six months ended June 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 12. 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 six months ended June 30, 2019 and the six months ended June 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 July 26, 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 impacts 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, 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 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, and
- anticipated performance of the acquired Goreway facility (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,
- 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 approximately 6,000 megawatts (MW) of power generation capacity at 26 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 six months ended June 30, 2019
Facility availability average	95% or greater	94%
Sustaining capital expenditures	$80 to 90 million	$40 million [1]

[1] Includes sustaining capital expenditures net of joint venture contributions of $3 million.

The Company's facility availability averaged 94% which reflected planned outages at Genesee, Cloverbar Energy Centre, Roxboro, Southport, Decatur Energy, Shepard, and Arlington Valley. Unplanned outages also occurred at Genesee, Shepard, EnPower and Cloverbar Energy Centre.

Sustaining capital expenditures for the six months ended June 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 half 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 June 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 six months ended June 30, 2019
Adjusted funds from operations [2]	$485 million to $535 million	$202 million
Adjusted EBITDA [2]	$870 million to $920 million	$393 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 half of 2019 and the Company's forecast for the second half 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 continuing to work with the Government of Alberta concerning the design of the Alberta wholesale power market. 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) and 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 June 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]	41%	4%	9%
Contracted price [2]	Mid-$50	Low-$60	Low-$50
Forward Alberta pool prices	$58	$59	$53

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							
	Jun 30 2019	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**
Revenues and other income [2]	366	397	340	395	369	313	267	352
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(134)	(167)	(233)	(261)	(152)	(153)	(125)	(198)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	(48)	(34)	53	35	(22)	1	18	3
Adjusted EBITDA from joint ventures [1]	7	6	11	10	12	18	18	10
Adjusted EBITDA	**191**	**202**	**171**	**179**	**207**	**179**	**178**	**167**
Depreciation and amortization [2]	(122)	(98)	(85)	(83)	(83)	(84)	(80)	(83)
Unrealized changes in fair value of commodity derivatives and emission credits	48	34	(53)	(35)	22	(1)	(18)	(3)
Impairments	-	-	-	-	-	-	-	(83)
Gain on disposal of joint venture	-	-	159	-	-	-	-	-
Foreign exchange (loss) gain	-	(4)	6	(2)	3	3	(4)	21
Net finance expense	(37)	(36)	(33)	(28)	(29)	(33)	(32)	(31)
Finance expense and depreciation expense from joint ventures [1]	(7)	(8)	(10)	(7)	(8)	(7)	(13)	(6)
Income tax recovery (expense) [2]	33	(30)	(19)	(7)	(46)	(18)	(45)	9
Net income (loss)	**106**	**60**	**136**	**17**	**66**	**39**	**(14)**	**(9)**
Net income (loss) attributable to:								
Non-controlling interests	(2)	(1)	(2)	(1)	(2)	(2)	(3)	(2)
Shareholders of the Company [2]	108	61	138	18	68	41	(11)	(7)
Net income (loss)	**106**	**60**	**136**	**17**	**66**	**39**	**(14)**	**(9)**

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 June 30**		**Six months ended June 30**	
	2019	**2018**	**2019**	**2018**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**114**	**109**	**400**	**252**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	26	25	47	50
Realized loss on settlement of interest rate derivatives	13	-	19	-
Change in fair value of derivatives reflected as cash settlement	(30)	(11)	(37)	(20)
Distributions received from joint ventures	(3)	(6)	(6)	(19)
Miscellaneous financing charges paid [1]	2	1	3	3
Income taxes paid	-	-	2	1
Change in non-cash operating working capital	34	10	(113)	(6)
	42	19	(85)	9
Net finance expense [2]	(29)	(24)	(57)	(49)
Current income tax expense [3]	(3)	(5)	(1)	(9)
Sustaining capital expenditures [4]	(31)	(20)	(40)	(41)
Preferred share dividends paid	(12)	(10)	(23)	(20)
Remove tax equity interests' respective shares of adjusted funds from operations	(1)	(2)	(2)	(4)
Adjusted funds from operations from joint ventures	5	9	10	23
Adjusted funds from operations	**85**	**76**	**202**	**161**
Weighted average number of common shares outstanding (millions)	**103.6**	**103.1**	**102.7**	**103.6**
Adjusted funds from operations per share ($)	**0.82**	**0.74**	**1.97**	**1.55**

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 $1 million and $3 million for the three and six months ended June 30, 2019, respectively, compared with $3 million and $5 million for the three and six months ended June 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							
	Jun 30 2019	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**
Basic earnings (loss) per share ($)[2]	**0.93**	**0.49**	**1.24**	**0.08**	**0.55**	**0.30**	**(0.21)**	**(0.15)**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss) [2]	**108**	**61**	**138**	**18**	**68**	**41**	**(11)**	**(7)**
Preferred share dividends including Part VI.1 tax	(12)	(11)	(11)	(10)	(11)	(10)	(11)	(9)
Earnings (loss) attributable to common shareholders [2]	96	50	127	8	57	31	(22)	(16)
Unrealized changes in fair value of derivatives [1]	(30)	(20)	35	26	(19)	25	14	(31)
Alberta tax rate change	(51)	-	-	-	-	-	-	-
Gain on disposal of joint venture	-	-	(134)	-	-	-	-	-
Non-cash tax equity adjustment	-	-	-	-	(15)	-	-	-
Realized foreign exchange (gain) loss on settlement of foreign currency derivative instruments	-	-	-	-	-	(29)	-	12
Asset held for sale accounting treatment of K2 Wind	-	-	3	-	-	-	-	-
Income tax adjustment	-	-	-	-	(2)	2	-	-
Impairments	-	-	-	-	-	-	-	53
Unrealized foreign exchange (gain) loss on revaluation of U.S. dollar denominated debt	-	-	-	-	-	-	(1)	44
Realized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	-	-	-	-	-	(1)	(35)
Provision for Line Loss Rule Proceeding	-	-	-	-	-	-	7	-
U.S. tax reform rate decrease	-	-	-	-	-	-	31	-
Success fee received related to development project	-	-	-	-	-	-	(3)	-
Release of tax liability on foreign domiciled investment	-	-	-	-	-	-	(1)	-
Normalized earnings attributable to common shareholders [2]	**15**	**30**	**31**	**34**	**21**	**29**	**24**	**27**
Weighted average number of common shares outstanding (millions)	103.6	101.8	102.3	102.4	103.1	104.2	104.3	104.1
Normalized earnings per share ($)[2]	**0.14**	**0.29**	**0.30**	**0.33**	**0.20**	**0.28**	**0.23**	**0.26**

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 June 30**		**Six months ended June 30**	
	2019	**2018**	**2019**	**2018**
Revenues and other income [3]	366	369	763	682
Adjusted EBITDA [1, 3]	191	207	393	386
Net income [3]	106	66	166	105
Net income attributable to shareholders of the Company [3]	108	68	169	109
Normalized earnings attributable to common shareholders [1, 3]	15	21	45	50
Basic earnings per share ($) [3]	0.93	0.55	1.42	0.85
Diluted earnings per share ($) [2, 3]	0.92	0.55	1.41	0.85
Normalized earnings per share ($) [1, 3]	0.14	0.20	0.44	0.48
Net cash flows from operating activities	114	109	400	252
Adjusted funds from operations [1]	85	76	202	161
Adjusted funds from operations per share ($) [1]	0.82	0.74	1.97	1.55
Purchase of property, plant and equipment and other assets	279	66	330	106
Dividends per common share, declared ($)	0.4475	0.4175	0.8950	0.8350
Dividends per Series 1 preferred share, declared ($)	0.1913	0.1913	0.3825	0.3825
Dividends per Series 3 preferred share, declared ($)	0.3408	0.2875	0.6816	0.5750
Dividends per Series 5 preferred share, declared ($)	0.3274	0.2813	0.6548	0.5626
Dividends per Series 7 preferred share, declared ($)	0.3750	0.3750	0.7500	0.7500
Dividends per Series 9 preferred share, declared ($)	0.3594	0.3594	0.7188	0.7188
Dividends per Series 11 preferred share, declared ($)	0.1772	-	0.1772	-

	As at	
	June 30, 2019	**December 31, 2018**
Loans and borrowings including current portion	3,279	2,647
Total assets	8,900	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 for the three and six months ended June 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 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. For the three months ended June 30, 2019, the increases in adjusted funds from operations were also partially offset by higher sustaining capital expenditures.

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

SIGNIFICANT EVENTS

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 preliminary 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 adjusted funds from operations (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.

SUBSEQUENT EVENT

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 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.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

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

(unaudited, $ millions)	Three months		Six months	
Consolidated net income for the periods ended June 30, 2018 [1]		**66**		**105**
Increase (decrease) in adjusted EBITDA:				
Alberta commercial facilities and portfolio optimization	20		49	
Alberta contracted facilities	(19)		(11)	
Ontario and British Columbia contracted facilities	3		(12)	
U.S. contracted facilities	(18)		(15)	
Corporate	(2)	(16)	(4)	7
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		26		61
Increase in depreciation and amortization expense		(39)		(53)
Decrease in foreign exchange gain		(3)		(10)
Decrease in finance expense and depreciation expense from joint ventures		1		-
Increase in net finance expense		(8)		(11)
Decrease in income before tax		(39)		(6)
Change in income tax expense or recovery		79		67
Increase in net income		**40**		**61**
Consolidated net income for the periods ended June 30, 2019		**106**		**166**

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 June 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	5,500	4,584	92	93	334	335		
Alberta commercial facilities [4]								
Genesee 3	502	468	100	98	29	26		
Keephills 3	433	434	92	100	25	24		
Clover Bar Energy Centre 1, 2 and 3	264	204	91	90	18	20		
Joffre	205	115	100	90	16	12		
Shepard Energy Centre	679	585	86	68	32	34		
Halkirk	107	103	98	98	10	10		
Clover Bar Landfill Gas	-	-	-	78	-	-		
Alberta commercial facilities	2,190	1,909	93	87	130	126		
Portfolio optimization	N/A	N/A	N/A	N/A	20	(10)		
	2,190	1,909	93	87	150	116	71	51
Alberta contracted facilities [4]								
Genesee 1	556	751	72	100				
Genesee 2	698	647	95	93				
	1,254	1,398	83	97	46	66	32	51
Ontario and British Columbia contracted facilities								
Island Generation	166	-	100	100	9	9		
York Energy [5]	4	3	100	94	N/A	N/A		
East Windsor	3	2	99	99	10	9		
Goreway [6]	76	N/A	99	N/A	16	N/A		
K2 Wind [7]	N/A	41	N/A	100	N/A	N/A		
Kingsbridge 1	20	20	97	98	2	2		
Port Dover and Nanticoke	65	70	100	99	9	10		
Quality Wind	77	98	98	97	9	10		
EnPower	5	11	97	86	1	1		
	416	245	99	98	56	41	48	45
U.S. contracted facilities								
Roxboro, North Carolina	88	90	100	99	10	10		
Southport, North Carolina	121	118	90	95	17	16		
Decatur Energy, Alabama	372	576	81	94	15	16		
Arlington Valley, Arizona [8]	750	N/A	100	N/A	33	N/A		
Beaufort Solar, North Carolina	9	8	100	98	-	1		
Bloom Wind, Kansas	169	197	98	96	11	54		
Macho Springs, New Mexico	43	43	99	98	6	5		
New Frontier Wind, North Dakota [9]	88	N/A	95	N/A	10	N/A		
	1,640	1,032	91	95	102	102	54	72
Corporate [10]					17	15	(14)	(12)
Unrealized changes in fair value of commodity derivatives and emission credits					(5)	29		
Consolidated revenues and other income and adjusted EBITDA					**366**	**369**	**191**	**207**

	Six months ended June 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	11,282	9,610	94	95	717	603		
Alberta commercial facilities [4]								
Genesee 3	1,002	947	100	98	63	43		
Keephills 3	903	854	95	96	53	39		
Clover Bar Energy Centre 1, 2 and 3	560	379	94	91	42	29		
Joffre	437	243	100	91	39	23		
Shepard Energy Centre	1,486	1,380	92	84	76	62		
Halkirk	227	235	98	98	24	22		
Clover Bar Landfill Gas	-	-	-	39	-	-		
Alberta commercial facilities	4,615	4,038	95	91	297	218		
Portfolio optimization	N/A	N/A	N/A	N/A	33	71		
	4,615	4,038	95	91	330	289	155	106
Alberta contracted facilities [4]								
Genesee 1	1,393	1,562	86	100				
Genesee 2	1,546	1,310	97	88				
	2,939	2,872	92	94	120	127	85	96
Ontario and British Columbia contracted facilities								
Island Generation	334	10	100	100	19	19		
York Energy [5]	8	5	100	97	N/A	N/A		
East Windsor	5	4	99	99	18	18		
Goreway [6]	76	N/A	99	N/A	16	N/A		
K2 Wind [7]	N/A	117	N/A	99	N/A	N/A		
Kingsbridge 1	56	56	98	98	5	5		
Port Dover and Nanticoke	164	178	99	99	24	26		
Quality Wind	151	176	97	97	20	21		
EnPower	10	25	77	92	1	2		
	804	571	99	98	103	91	92	104
U.S. contracted facilities								
Roxboro, North Carolina	150	166	94	94	18	18		
Southport, North Carolina	220	229	91	92	32	31		
Decatur Energy, Alabama	780	1,245	89	97	38	39		
Arlington Valley, Arizona [8]	1,144	N/A	91	N/A	55	N/A		
Beaufort Solar, North Carolina	15	14	100	94	1	1		
Bloom Wind, Kansas	344	395	99	97	23	69		
Macho Springs, New Mexico	82	80	98	98	10	9		
New Frontier Wind, North Dakota [9]	189	N/A	95	N/A	20	N/A		
	2,924	2,129	91	96	197	167	92	107
Corporate [10]					32	30	(31)	(27)
Unrealized changes in fair value of commodity derivatives and emission credits					(19)	(22)		
Consolidated revenues and other income and adjusted EBITDA					**763**	**682**	**393**	**386**

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 $8 million and $16 million for three and six months ended June 30, 2019, respectively, compared with $8 million and $15 million for the three and six months ended June 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 June 30		Six months ended June 30		Year ended
Alberta	**Unit**	**2019**	**2018**	**2019**	**2018**	**December 31, 2018**
Hedged position [1]	Percentage sold forward at beginning of period (%)	100	93	85	89	87
Spot power price average	$ per MWh	57	56	63	46	50
Realized power price [2]	$ per MWh	55	51	57	49	51
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	1.17	1.10	1.98	1.54	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 $57 per MWh and $63 per MWh for the three and six months ended June 30, 2019, respectively which were higher than the corresponding periods in 2018 as a result of unseasonably cold temperatures, the impact of higher natural gas pricing, baseload facility outages and derates, low wind generation and a high volume of power exports. The spot power price average for 2018 reflected minimal market volatility combined with conservative offer strategies from market participants, stable baseload supply, strong imports and low natural gas prices.

For the three and six months ended June 30, 2019, generation was higher than the comparable periods in 2018 primarily due to higher dispatch at Shepard, Joffre and Clover Bar Energy Centre. Higher overall availability for the three and six months ended June 30, 2019 was primarily due to a shorter planned outage at Shepard in the second quarter of 2019 compared with the same period in 2018.

Revenues and other income for the three and six months ended June 30, 2019 increased compared with the corresponding periods in 2018 primarily due to increased generation and captured pricing from commercial facilities. Adjusted EBITDA for the three and six months ended June 30, 2019 also increased, compared to the corresponding periods in 2018. These increases were driven by higher generation and realized power pricing, higher margins earned on the sale of emission credits and favourable margins earned on export activity. These favourable variances were 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 and six months ended June 30, 2019 was lower compared with the corresponding periods in 2018 primarily due to the timing of the Genesee 2 planned maintenance outage which commenced in the first quarter of 2018 as compared to the Genesee 1 planned outage which occurred in the second quarter of 2019, the latter of which was also four days longer.

Generation for the three months ended June 30, 2019 was also lower than the corresponding period in 2018 due to the noted timing and length of the 2019 and 2018 planned outages. Despite the length and timing of the 2019 planned outage, generation for the six months ended June 30, 2019 was higher than in 2018 partially due to lower dispatch by the PPA buyer in 2018, compared with 2019.

Revenues and other income and adjusted EBITDA were lower in the three and six months ended June 30, 2019 compared with the corresponding periods in 2018 primarily as a result of the noted planned outage timing and 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 six months ended June 30, 2019 also reflected higher excess energy payments, running energy payments and coal costs compared with 2018.

Ontario and British Columbia contracted facilities

Generation for the three and six months ended June 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 lower generation at Quality Wind and the sale of K2 Wind in the fourth quarter of 2018. Availability in 2019 was consistent with 2018.

Revenues and other income were higher for the three and six months ended June 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 months ended June 30, 2019 was higher than the corresponding period in 2018 while adjusted EBITDA for the six months ended June 30, 2019 was lower than the corresponding period in 2018 primarily due to the offsetting impacts of the acquisition of Goreway in 2019 and 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 six months ended June 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 and lower wind capacity at Bloom Wind.

Availability decreased in the six months ended June 30, 2019 compared with the corresponding period in 2018 primarily due to a longer planned outage at Decatur in 2019 compared with the planned outage in 2018. Availability decreased in the three months ended June 30, 2019 compared with the corresponding period in 2018 primarily due to the noted Decatur planned outage length as well as the timing of the Southport planned outage in 2019, with a portion of that outage occurring in the second quarter of 2019 compared with the entire 2018 planned outage occurring in the first quarter of 2018.

Revenues and other income for the three and six months ended June 30, 2019 are consistent with, and higher than the corresponding periods in 2018 respectively, 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 the impacts of the updated Bloom tax equity investor agreement signed during the second quarter of 2018.

Adjusted EBITDA for the three and six months ended June 30, 2019 is lower than the corresponding periods in 2018 primarily due to the impacts of the updated Bloom tax equity investor agreement signed during the second quarter of 2018 and higher planned outage costs at Decatur in 2019 compared with 2018, partially offset by the addition of Arlington Valley and the commencement of commercial operations at New Frontier Wind in the fourth quarter of 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 three and six months ended June 30, 2019 due 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 for the three and six months ended June 30, 2019 were higher than the corresponding period in 2018 mainly due to higher business development expenses resulting from higher acquisition costs related to Goreway and the write off of previously capitalized costs related to the Black Fork development project as the project will not continue to be developed as a wind facility, partly offset by the increased revenues noted above.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Three months ended June 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	(35)	9	23	(3)
Unrealized gains on U.S. energy derivatives	31	25	31	25
Unrealized gains (losses) on natural gas derivatives	2	(9)	(1)	(5)
Unrealized (losses) gains on emission derivatives	(3)	4	(3)	4
Unrealized (losses) gains on emission credits held for trading	-	-	(2)	1
	(5)	**29**	**48**	**22**

(unaudited, $ millions)	Six months ended June 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	(60)	(44)	31	(3)
Unrealized gains on U.S. energy derivatives	41	24	41	24
Unrealized gains (losses) on natural gas derivatives	1	(10)	17	(3)
Unrealized (losses) gains on emission derivatives	(1)	8	(1)	8
Unrealized losses on emission credits held for trading	-	-	(6)	(5)
	(19)	**(22)**	**82**	**21**

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 June 30, 2019 the Alberta energy portfolio recognized unrealized gains of $23 million compared to unrealized losses of $3 million in the comparable quarter in 2018. 2019 gains were primarily the result of the impact of increasing forward power prices on net forward purchase contracts. 2018 losses were due to the reversal of prior period unrealized net gains on forward sales contracts that settled during the quarter. During the six months ended June 30, 2019, the Alberta energy portfolio recognized unrealized gains of $31 million compared to unrealized losses of $3 million in 2018. 2019 gains were primarily the result of the impact of increasing forward power prices on net forward purchase contracts. 2018 losses were due to the reversal of prior period unrealized net gains on forward sales contracts that settled.

During the three and six months ended June 30, 2018 and 2019, the company recorded unrealized gains on U.S. energy derivatives, as a result of decreasing forward prices on forward sales contracts in the respective periods.

Unrealized gains on natural gas derivatives during the six months ended June 30, 2019 were attributable to net forward purchase contracts valued against increasing forward natural gas prices, and the reversal of prior periods’ unrealized losses on positions that settled in the period. Unrealized losses on natural gas derivatives for the three and six months ended June 30, 2018 were attributable to net forward purchase contracts valued against decreasing forward natural gas prices, partially offset by the reversal of prior period unrealized losses on positions that settled in 2018.

Unrealized losses on emissions derivatives in 2019 were due to net forward purchase contracts being valued against decreasing forward prices. Unrealized gains on emission derivatives in 2018 were primarily due to forward purchase contracts on emissions allowances and renewable energy credits which were valued against increasing forward prices and the impact of the reversal of previously unrealized losses on positions that settled during the respective periods.

During the six months ended June 30, 2019 and 2018, the company recorded unrealized losses on emission credits held for trading, primarily due to the reversal of prior period unrealized gains on emission credits sold during those periods.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Three months ended June 30		Six months ended June 30	
	2019	2018	2019	2018
Interest on borrowings less capitalized interest	(31)	(27)	(62)	(56)
Other net finance expense – interest on coal compensation from the Province of Alberta, sundry interest, guarantee and other fees	-	3	1	5
	(31)	(24)	(61)	(51)
Other net finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta	(6)	(5)	(12)	(11)
Total net finance expense	(37)	(29)	(73)	(62)
Depreciation and amortization	(122)	(83)	(220)	(167)
Foreign exchange gain (loss)	-	3	(4)	6
Finance expense and depreciation expense from joint ventures	(7)	(8)	(15)	(15)
Income tax recovery (expense)	33	(46)	3	(64)
Net loss attributable to non-controlling interests	2	2	3	4

Net finance expense

Higher net finance expense for the three and six months ended June 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).

Depreciation and amortization

Depreciation and amortization for the three and six months ended June 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.

Foreign exchange gain (loss)

For the three and six months ended June 30, 2019, the exchange rate of the Canadian dollar relative to the U.S. dollar strengthened resulting in an unrealized loss. The unrealized loss occurred substantially during the first quarter of 2019 driven by the net outstanding foreign currency purchase contracts during that period. The foreign exchange movement during the three months ended June 30, 2019 was nominal driven by offsetting impacts of exchange rate changes on foreign currency purchase and sale contracts outstanding at various times during the quarter.

As at June 30, 2018, the Company had outstanding foreign currency purchase contracts totalling US$133 million. For the three and six months ended June 30, 2018, the exchange rate of the Canadian dollar relative to the U.S. dollar weakened resulting in an unrealized gain in both periods.

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 six months ended June 30, 2019 income tax expense decreased $79 million and $67 million, respectively, compared with the corresponding periods in 2018 primarily due to the decrease in the Alberta corporate income tax rate enacted in the second quarter of 2019, which reduced deferred tax liabilities on the statement of the financial position, and lower amounts attributable to tax-equity interests driven by the updated Bloom 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 quarter.

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 INCOME

(unaudited, $ millions)	Three months ended June 30		Six months ended June 30	
	2019	**2018**	**2019**	**2018**
Net income	106	66	166	105
Other comprehensive (loss) income:				
Net unrealized losses on commodity derivatives designated as cash flow hedges	(39)	(6)	(72)	(19)
Net unrealized gains on derivatives designated as cash flow hedges – joint ventures	-	1	-	1
Net realized losses on commodity derivatives designated as cash flow hedges reclassified to net income	6	9	20	1
Net realized losses on commodity derivatives designated as cash flow hedges reclassified to net income – joint ventures	-	1	-	1
Unrealized foreign exchange (losses) gains on the translation of foreign operations	(18)	9	(33)	20
	(51)	14	(85)	4
Comprehensive income	**55**	**80**	**81**	**109**

Other comprehensive income 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 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 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 June 30, 2019 were as follows:

(unaudited, $ millions)	**As at June 30, 2019**	**As at December 31, 2018**	**Increase (decrease)**	**IFRS 16 Impact (see Accounting Changes)**	**Acquisitions through business combinations**	**Other**	**Primary other changes**
Trade and other receivables [1]	296	438	(142)	(2)	22	(162)	Lower receivables are driven by the receipt of the remaining proceeds on disposal of K2 Wind and timing of collection of generation receivables.
Net derivative financial instruments liabilities	160	45	115	-	105	10	Impact of increasing forward power prices on forward power sales contracts, settlement of foreign exchange and natural gas non-hedge contracts partially offset by settlement of interest rate hedge derivatives.
Right-of-use assets	95	-	95	86	-	9	Reclassification from property, plant and equipment.
Intangible assets	925	473	452	-	500	(48)	Decrease primarily due to emission credits used for compliance and transferred to inventory.

(unaudited, $ millions)	As at June 30, 2019	As at December 31, 2018	Increase (decrease)	IFRS 16 Impact (see Accounting Changes)	Acquisitions through business combinations	Other	Primary other changes
Property, plant and equipment[1]	6,286	5,356	930	-	821	109	Increase primarily due to capital additions, including Whitla Wind and Cardinal Point Wind, partly offset by depreciation.
Loans and borrowings (including current portion)	3,279	2,647	632	-	590	42	Increase primarily due to issuance of private placement senior notes (see Significant Events and medium-term note, partially offset by net repayment of credit facilities.
Lease liabilities (including current portion)	110	18	92	96	-	(4)	Decrease primarily due to lease payments.
Net deferred tax liabilities [1]	497	351	146	(2)	208	(60)	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.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Six months ended June 30		
Cash inflows (outflows)	**2019**	**2018**	**Change**
Operating activities	400	252	148
Investing activities	(672)	(88)	(584)
Financing activities	263	(168)	431

Operating activities

Cash flows from operating activities for the six months ended June 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 three and six months ended June 30, 2019 when compared to the same period in the previous year driven by higher Alberta power prices and generation. In addition, there were working capital cash inflows in 2019 compared with outflows in 2018 primarily due to the collection of outstanding receivables from the disposal of K2 Wind. Partially offsetting these increases were net realized cash losses on certain interest rate derivative instruments recognized during the six months ended June 30, 2019.

Investing activities

Cash flows used in investing activities for the six months ended June 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.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2019 Actual	Six months ended June 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 as early as 2022
New Frontier Wind [5]	174	2	4	180	Completed in December 2018
Whitla Wind [6]	71	142	127	340	Targeted completion in the fourth quarter of 2019
Cardinal Point Wind [7]	28	107	133	295	Targeted completion in March of 2020
Commercial initiatives [8]	-	32	32	96	
Development sites and projects	15	-	-		
Subtotal growth projects		**283**	**296**		
Sustaining – facility maintenance excluding Genesee mine		39			
Sustaining – Genesee mine maintenance and lands		4			
Total capital expenditures [9]		**43**			
Emission credits held for compliance		8			
Capitalized interest		(4)			
Purchase of property, plant and equipment and other assets		**330**			

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 $2 million at June 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 second quarter of 2019 of $6 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.

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 six months ended June 30, 2019 primarily reflected the net issuance of loans and borrowings, issuance of common and preferred shares (see Significant Events) and payment of common and preferred share dividends.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at June 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			144			99	
Bankers' acceptances outstanding			250			396	
Bank loans outstanding [1]			109			218	
		1,250	503	747	1,150	713	437
Bilateral demand credit facilities	N/A	200			200		
Letters of credit outstanding			164			172	
		200	164	36	200	172	28
Demand credit facilities	N/A	25	-	25	25	-	25
		1,475	**667**	**808**	**1,375**	**885**	**490**

1 U.S. dollar denominated bank loans outstanding totaling US$84 million (December 31, 2018 – US $160 million).

As at June 30, 2019, the committed credit facility utilization decreased $210 million compared with the utilization as at December 31, 2018, due to decreased bankers' acceptance and U.S. dollar bank loans partially offset by increased letters of credit outstanding. 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 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)	Six months ended June 30, 2019 actual	Balance of 2019 estimated	Total 2019 expected cash requirements
Net repayment of debt payable	98	212	310
Capital expenditures – sustaining	40	49	89
Capital expenditures – ongoing growth projects	283	296	579
Common share dividends [1]	91	99	190
Preferred share dividends	23	25	48
	535	**681**	**1,216**

1 Includes 7.3% annual dividend growth (see Subsequent Event).

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 June 30, 2019, the Company has $308 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	
	June 30, 2019	**December 31, 2018**
Loans and borrowings	3,279	2,647
Lease liabilities[1]	110	18
Less cash and cash equivalents	(168)	(182)
Net debt	3,221	2,483
Share capital	3,497	3,200
Deficit and other reserves	(230)	(190)
Non-controlling interests	40	43
Total equity	3,307	3,053
Total capital	**6,528**	**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 appeal and other 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 billing 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 billing for the line loss adjustments will not occur until 2021.

RISKS AND RISK MANAGEMENT

There have been no material changes in the six months ended June 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 $339 million as at June 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 $521 million and forward contracts to sell environmental credits totaling $505 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

During July of 2019, Ontario's Independent Electric System Operator announced unexpectedly that they were cancelling further work on a capacity market. They advised they have reviewed their long-term planning outlook, and over the next ten years they expect sufficient capacity exists in the market if resources are reacquired when their contracts expire. The process to recontract assets has yet to be defined, but it 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. Management's understanding is 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, though specific design components will potentially be subject to revision as part of the review. Capital Power will participate in consultations on the TIER framework.

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 replaces 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 has 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 June 30, 2019			Three months ended June 30, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	328	334	6	296	302	6
Depreciation and amortization	(113)	(122)	(9)	(74)	(83)	(9)
Income tax recovery (expense)	32	33	1	(47)	(46)	1
Net income (loss) impact			(2)			(2)

	Six months ended June 30, 2019			Six months ended June 30, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	687	699	12	576	588	12
Depreciation and amortization	(202)	(220)	(18)	(149)	(167)	(18)
Income tax recovery (expense)	1	3	2	(66)	(64)	2
Net income (loss) impact			(4)			(4)

FINANCIAL INSTRUMENTS

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

(unaudited, $ millions)		June 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	168	168	182	182
Trade and other receivables [2]	N/A	243	243	385	385
Government grant receivable [3]	Level 2	519	481	511	505
Fair value through income or loss					
Derivative financial instruments assets – current and non-current	See below	169	169	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	313	313	244	244
Loans and borrowings [3]	Level 2	3,279	3,019	2,647	2,645
Fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See below	183	183	186	186
Fair value through other comprehensive income					
Derivative financial instruments liabilities – current and non-current	See below	147	147	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 six months ended June 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 June 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 June 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	142	-	2	145
	Level 3	-	25	-	-	25
		1	167	-	2	170
Derivative financial instruments liabilities	Level 2	(41)	(172)	(106)	-	(319)
	Level 3	-	(11)	-	-	(11)
		(41)	(183)	(106)	-	(330)
Net derivative financial instruments (liabilities) assets		**(40)**	**(16)**	**(106)**	**2**	**(160)**

(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 loss and, when realized, are reclassified to net 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 income 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 six months ended June 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	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**
Total generation	5,500	5,782	5,406	5,213	4,584	5,026	4,839	4,720
Alberta commercial facilities								
Genesee 3	502	500	372	495	468	479	511	509
Keephills 3	433	470	483	494	434	420	362	380
Clover Bar Energy Centre 1, 2 and 3	264	296	264	217	204	175	92	140
Joffre	205	232	212	154	115	128	119	101
Shepard Energy Centre	679	807	769	789	585	795	694	730
Halkirk	107	120	130	85	103	132	168	95
Clover Bar Landfill Gas	-	-	-	-	-	-	2	6
	2,190	2,425	2,230	2,234	1,909	2,129	1,948	1,961
Alberta contracted facilities								
Genesee 1	556	837	877	829	751	811	860	830
Genesee 2	698	848	850	799	647	663	864	823
	1,254	1,685	1,727	1,628	1,398	1,474	1,724	1,653
Ontario and British Columbia contracted facilities								
Island Generation	166	168	-	17	-	10	3	12
York Energy	4	4	2	3	3	2	2	5
East Windsor	3	2	1	4	2	2	1	2
Goreway	76	N/A	N/A	N/A	N/A	N/A	N/A	N/A
K2 Wind	N/A	N/A	70	35	41	76	57	28
Kingsbridge 1	20	36	33	14	20	36	37	11
Port Dover and Nanticoke	65	99	78	43	70	108	84	39
Quality Wind	77	74	112	74	98	78	117	85
EnPower	5	5	3	10	11	14	13	7
	416	388	299	200	245	326	314	189
U.S. contracted facilities								
Roxboro, North Carolina	88	62	74	87	90	76	86	80
Southport, North Carolina	121	99	106	104	118	111	120	124
Decatur Energy, Alabama	372	408	674	784	576	669	425	542
Arlington Valley, Arizona	750	394	87	N/A	N/A	N/A	N/A	N/A
Beaufort Solar, North Carolina	9	6	5	8	8	6	6	7
Bloom Wind, Kansas	169	175	164	152	197	198	190	145
Macho Springs, New Mexico	43	39	31	16	43	37	26	19
New Frontier Wind, North Dakota	88	101	9	N/A	N/A	N/A	N/A	N/A
	1,640	1,284	1,150	1,151	1,032	1,097	853	917

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

Financial results

(unaudited, $ millions)	Three months ended							
	Jun 30 2019	Mar 31 2019	Dec 31 2018	Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sep 30 2017
Revenues and other income								
Alberta commercial facilities and portfolio optimization	150	180	150	148	116	173	190	160
Alberta contracted facilities	46	74	71	70	66	61	64	61
Ontario and British Columbia contracted facilities [3]	56	47	52	37	41	50	54	37
U.S. contracted facilities	102	95	63	74	102	65	58	77
Corporate [1]	17	15	13	15	15	15	19	14
Unrealized changes in fair value of commodity derivatives and emission credits	(5)	(14)	(9)	51	29	(51)	(118)	3
	366	**397**	**340**	**395**	**369**	**313**	**267**	**352**
Adjusted EBITDA								
Alberta commercial facilities and portfolio optimization	71	84	62	60	51	55	60	55
Alberta contracted facilities	32	53	53	54	51	45	47	41
Ontario and British Columbia contracted facilities [2, 3]	48	44	52	37	45	59	60	37
U.S. contracted facilities	54	38	25	44	72	35	30	46
Corporate	(14)	(17)	(21)	(16)	(12)	(15)	(19)	(12)
	191	**202**	**171**	**179**	**207**	**179**	**178**	**167**

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							
	Jun 30 2019	Mar 31 2019	Dec 31 2018	Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sep 30 2017
Revenues and other income [4]	366	397	340	395	369	313	267	352
Adjusted EBITDA [1, 2, 3, 4]	191	202	171	179	207	179	178	167
Net income (loss) [4]	106	60	136	17	66	39	(14)	(9)
Net income (loss) attributable to shareholders of the Company [4]	108	61	138	18	68	41	(11)	(7)
Basic earnings (loss) per share ($) [4]	0.93	0.49	1.24	0.08	0.55	0.30	(0.21)	(0.15)
Normalized earnings per share ($) [1, 4]	0.14	0.29	0.30	0.33	0.20	0.28	0.23	0.26
Net cash flows from operating activities	114	286	133	65	109	143	75	120
Adjusted funds from operations [1]	85	117	80	156	76	85	94	135
Adjusted funds from operations per share ($) [1]	0.82	1.15	0.78	1.52	0.74	0.82	0.90	1.30
Purchase of property, plant and equipment and other assets	279	51	114	135	66	40	42	28

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 EBTIDA 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	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**
Alberta power ($ per MWh)	57	69	56	55	56	35	22	25
Alberta natural gas (AECO) ($ per Gj)	1.17	2.62	1.59	1.15	1.10	1.99	1.73	1.34
Capital Power's Alberta portfolio average realized power price ($ per MWh)	55	58	52	54	51	47	46	49

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 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.

Financial results for the third quarter of 2017 reflected the impact of low Alberta power pricing averaging $25 per MWh. Revenues were lower compared with the corresponding period in 2016 mainly due to 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 increased quarter over quarter mostly attributable to the acquisition of the thermal facilities and Decatur Energy in the second quarter of 2017 and other income related to coal compensation from the Province of Alberta. The Company recognized 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.

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							
	Jun 30 2019	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**
Share price ($/common share)								
High	32.25	32.44	29.79	29.45	26.00	25.14	25.59	26.51
Low	29.60	26.22	25.33	25.12	23.42	22.15	23.26	23.81
Close	30.15	31.30	26.59	28.51	25.23	24.24	24.49	24.67
Volume of shares traded (millions)	19.9	18.0	25.5	14.8	11.1	14.0	16.9	14.1

Outstanding share and partnership unit data

As at July 23, 2019, the Company had 106.921 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 July 23, 2019 were 110.431 million. The outstanding special limited voting share is held by EPCOR.

As at July 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)
Six months ended June 30, 2019 and 2018

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Six months ended June 30, 2019 and 2018

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2019	Three months ended June 30, 2018 (note 3)	Six months ended June 30, 2019	Six months ended June 30, 2018 (note 3)
Revenues	$ 334	$ 302	$ 699	$ 588
Other income	32	67	64	94
Energy purchases and fuel	(28)	(63)	(95)	(127)
Gross margin	338	306	668	555
Other raw materials and operating charges	(36)	(32)	(69)	(64)
Staff costs and employee benefits expense	(41)	(34)	(80)	(68)
Depreciation and amortization	(122)	(83)	(220)	(167)
Other administrative expense	(29)	(23)	(57)	(46)
Foreign exchange gain (loss)	-	3	(4)	6
Operating income	110	137	238	216
Net finance expense	(37)	(29)	(73)	(62)
Income (loss) from joint ventures	-	4	(2)	15
Income before tax	73	112	163	169
Income tax recovery (expense) (note 5)	33	(46)	3	(64)
Net income	$ 106	$ 66	$ 166	$ 105
Attributable to:				
Non-controlling interests	$ (2)	$ (2)	$ (3)	$ (4)
Shareholders of the Company	$ 108	$ 68	$ 169	$ 109
Earnings per share (attributable to common shareholders of the Company):				
Basic (note 6)	$ 0.93	$ 0.55	$ 1.42	$ 0.85
Diluted (note 6)	$ 0.92	$ 0.55	$ 1.41	$ 0.85

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2019	Three months ended June 30, 2018 (note 3)	Six months ended June 30, 2019	Six months ended June 30, 2018 (note 3)
Net income	$ 106	$ 66	$ 166	$ 105
Other comprehensive (loss) income:				
Items that are or may be reclassified subsequently to net income:				
Cash flow hedges:				
Unrealized losses on derivative instruments[1]	(39)	(6)	(72)	(19)
Unrealized gains on derivative instruments – joint ventures[2]	-	1	-	1
Reclassification of losses on derivative instruments to income for the period[3]	6	9	20	1
Reclassification of losses on derivative instruments to net income for the period – joint ventures[4]	-	1	-	1
Net investment in foreign subsidiaries:				
Unrealized (losses) gains [2]	(18)	9	(33)	20
Total items that are or may be reclassified subsequently to net income, net of tax	(51)	14	(85)	4
Total other comprehensive (loss) income, net of tax	(51)	14	(85)	4
Total comprehensive income	$ 55	$ 80	$ 81	$ 109
Attributable to:				
Non-controlling interests	$ (2)	$ (2)	$ (3)	$ (4)
Shareholders of the Company	$ 57	$ 82	$ 84	$ 113

[1] For the three and six months ended June 30, 2019, net of income tax recovery of $9 million and $21 million respectively. For the three and six months ended June 30, 2018, net of income tax recovery of $2 million and $7 million respectively.

[2] For the three and six months ended June 30, 2019 and June 30, 2018, net of income tax expense of nil.

[3] For the three and six months ended June 30, 2019, net of reclassification of income tax recovery of nil and $6 million respectively. For the three and six months ended June 30, 2018, net of reclassification of income tax recovery of $4 million and $1 million respectively.

[4] For the three and six months ended June 30, 2019 and June 30, 2018, net of reclassification 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)

	June 30, 2019	December 31, 2018 (note 3)
Assets		
Current assets:		
Cash and cash equivalents	$ 168	$ 182
Trade and other receivables	296	438
Inventories	223	200
Derivative financial instruments assets (note 7)	73	77
	760	897
Non-current assets:		
Other assets	58	66
Derivative financial instruments assets (note 7)	97	82
Government grant receivable	466	459
Deferred tax assets	44	59
Equity-accounted investments	134	142
Right-of-use assets (note 8)	95	-
Intangible assets	925	473
Property, plant and equipment	6,286	5,356
Goodwill	35	35
Total assets	$ 8,900	$ 7,569
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 313	$ 244
Derivative financial instruments liabilities (note 7)	117	90
Loans and borrowings (note 9)	343	456
Deferred revenue and other liabilities	70	62
Provisions	39	54
	882	906
Non-current liabilities:		
Derivative financial instruments liabilities (note 7)	213	114
Loans and borrowings (note 9)	2,936	2,191
Lease liabilities (note 8)	104	17
Deferred revenue and other liabilities	548	587
Deferred tax liabilities	541	410
Provisions	369	291
	4,711	3,610
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 10)	3,497	3,200
Deficit	(176)	(222)
Other reserves	(54)	32
Deficit and other reserves	(230)	(190)
	3,267	3,010
Non-controlling interests	40	43
Total equity	3,307	3,053
Total liabilities and equity	$ 8,900	$ 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 10)	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 income	-	-	-	-	-	169	169	(3)	166
Other comprehensive (loss) income:									
Cash flow derivative hedge losses	-	(93)	-	-	-	-	(93)	-	(93)
Reclassification of losses to net income	-	26	-	-	-	-	26	-	26
Unrealized loss on foreign currency translation	-	-	(33)	-	-	-	(33)	-	(33)
Tax on items recognized directly in equity	-	15	-	-	-	-	15	-	15
Other comprehensive loss	$ -	$ (52)	$ (33)	$ -	$ -	$ -	$ (85)	$ -	$ (85)
Total comprehensive (loss) income	-	(52)	(33)	-	-	169	84	(3)	81
Common share dividends (note 10)	-	-	-	-	-	(94)	(94)	-	(94)
Preferred share dividends (note 10)	-	-	-	-	-	(23)	(23)	-	(23)
Issue of share capital	300	-	-	-	-	-	300	-	300
Share issue costs	(10)	-	-	-	-	-	(10)	-	(10)
Common shares purchased	(10)	-	-	-	-	-	(10)	-	(10)
Share options exercised	17	-	-	-	(1)	-	16	-	16
Equity as at June 30, 2019	$ 3,497	$ (45)	$ (10)	$ (9)	$ 10	$ (176)	$ 3,267	$ 40	$ 3,307

[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 10)	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	-	-	-	-	-	109	109	(4)	105
Other comprehensive (loss) income:									
Cash flow derivative hedge losses	-	(26)	-	-	-	-	(26)	-	(26)
Cash flow derivative hedge gains – joint ventures	-	1	-	-	-	-	1	-	1
Reclassification of losses to net income	-	2	-	-	-	-	2	-	2
Reclassification of losses to net income – joint venture	-	1	-	-	-	-	1	-	1
Unrealized gain on foreign currency translation	-	-	20	-	-	-	20	-	20
Tax on items recognized directly in equity	-	6	-	-	-	-	6	-	6
Other comprehensive (loss) income	$ -	$ (16)	$ 20	$ -	$ -	$ -	$ 4	$ -	$ 4
Total comprehensive (loss) income	-	(16)	20	-	-	109	113	(4)	109
Common share dividends (note 10)	-	-	-	-	-	(86)	(86)	-	(86)
Preferred share dividends (note 10)	-	-	-	-	-	(20)	(20)	-	(20)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Common shares purchased	(42)	-	-	-	-	-	(42)	-	(42)
Share-based payments	-	-	-	-	1	-	1	-	1
Share options exercised	2	-	-	-	-	-	2	-	2
Equity as at June 30, 2018	$ 3,222	$ (55)	$ (7)	$ (11)	$ 11	$ (269)	$ 2,891	$ 44	$ 2,935

[1] Accumulated other comprehensive (loss) income. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive (loss) income 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)

	Six months ended June 30, 2019	Six months ended June 30, 2018 (note 3)
Cash flows from operating activities:		
Net income	$ 166	$ 105
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	220	167
Net finance expense	73	62
Fair value changes on commodity derivative instruments and emission credits held for trading	(82)	(21)
Foreign exchange losses (gains)	4	(6)
Income tax (recovery) expense	(3)	64
Loss (income) from joint ventures	2	(15)
Recognition of government grant deferred revenue	(27)	(25)
Tax equity attributes	(30)	(64)
Other items	5	-
Change in fair value of derivative instruments reflected as cash settlement	37	20
Distributions received from joint ventures	6	19
Interest paid[1]	(47)	(50)
Other cash items	(37)	(10)
Change in non-cash operating working capital	113	6
Net cash flows from operating activities	400	252
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(330)	(106)
Business acquisition, net of acquired cash (note 4)	(390)	-
Other cash flows from investing activities	10	5
Realized gain on foreign currency derivative instruments	6	-
Change in non-cash investing working capital	32	13
Net cash flow used in investing activities	(672)	(88)
Cash flows from (used in) financing activities:		
Proceeds from issue of loans and borrowings	875	133
Repayment of loans and borrowings	(777)	(173)
Realized gain on foreign currency derivative instruments	-	33
Issue costs on loans and borrowings	(3)	(1)
Issue of share capital	300	-
Share issue costs	(10)	-
Proceeds from exercise of share options	16	2
Common shares purchased (note 10)	(10)	(42)
Dividends paid (note 10)	(114)	(107)
Capitalized interest paid[1]	(4)	(1)
Income taxes paid on preferred share dividends	(10)	(12)
Net cash flows from (used in) financing activities	263	(168)
Foreign exchange (loss) gain on cash held in a foreign currency	(5)	1
Net decrease in cash and cash equivalents	(14)	(3)
Cash and cash equivalents at beginning of period	182	52
Cash and cash equivalents at end of period	$ 168	$ 49

[1] Total interest paid.

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 July 26, 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 12.

For further disclosure on the Company's leases, see note 8.

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 pertaining to the IAS 8 accounting policy change related to the former finance leases where the Company was the lessor were:

	Three months ended June 30, 2019			Three months ended June 30, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	328	334	6	296	302	6
Depreciation and amortization	(113)	(122)	(9)	(74)	(83)	(9)
Income tax recovery (expense)	32	33	1	(47)	(46)	1
Net income (loss) impact			(2)			(2)

	Six months ended June 30, 2019			Six months ended June 30, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	687	699	12	576	588	12
Depreciation and amortization	(202)	(220)	(18)	(149)	(167)	(18)
Income tax recovery (expense)	1	3	2	(66)	(64)	2
Net income (loss) impact			(4)			(4)

Basic and diluted earnings per share for the three months ended June 30, 2019 and 2018 decreased by $0.02 and $0.02 respectively for the change in accounting policy pertaining to leases where the Company was the lessor. For the six months ended June 30, 2019 and 2018, basic and diluted earnings per share decreased by $0.04 and $0.04 respectively.

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

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 preliminary working capital and other closing adjustments of $23 million, and (ii) the assumption of $590 million of asset level debt.

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 working capital and other closing adjustments which is expected to occur in the second half 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 June 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.

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

4. Acquisition of the Goreway Power Station, continued:

The results of operations of Goreway are included in the Company's consolidated statements of income 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, $16 million of revenues and $3 million of net income are included in the consolidated statements of income for the three and six months ended June 30, 2019.

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

	Three months ended June 30, 2019			Six months ended June 30, 2019		
	Consolidated, excluding Goreway	Goreway	Consolidated, including Goreway	Consolidated, excluding Goreway	Goreway	Consolidated, including Goreway
Revenues	$ 334	$ 38	$ 372	$ 699	$ 93	$ 792
Net income	106	8	114	166	22	188

In conjunction with the acquisition of Goreway, for the three and six months ended June 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. 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 June 30, 2019	Three months ended June 30, 2018 (note 3)	Six months ended June 30, 2019	Six months ended June 30, 2018 (note 3)
Income before tax	$ 73	$ 112	$ 163	$ 169
Income tax at the statutory rate of 26.5%[1] (2018 – 27.0%)	19	30	43	45
Increase (decrease) resulting from:				
Amounts attributable to non-controlling interests and tax-equity interests	4	19	9	23
Change in unrecognized tax benefits	1	-	1	-
Non-taxable amounts	(2)	(2)	(3)	(8)
Statutory and other rate differences[1]	(54)	(1)	(53)	3
Other	(1)	-	-	1
Income tax (recovery) expense	$ (33)	$ 46	$ (3)	$ 64

[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.

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

6. Earnings per share:

Basic earnings per share

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

	Three months ended June 30, 2019	Three months ended June 30, 2018 (note 3)	Six months ended June 30, 2019	Six months ended June 30, 2018 (note 3)
Income for the period attributable to shareholders of the Company	$ 108	$ 68	$ 169	$ 109
Preferred share dividends of the Company[1]	(12)	(11)	(23)	(21)
Earnings used in the calculation of basic earnings per share	$ 96	$ 57	$ 146	$ 88

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

	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Weighted average number of common shares used in the calculation of basic earnings per share	103,591,977	103,135,456	102,708,937	103,649,630

Diluted earnings per share

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

	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Weighted average number of common shares used in the calculation of basic earnings per share	103,591,977	103,135,456	102,708,937	103,649,630
Effect of dilutive share purchase options[2]	701,984	316,453	701,801	285,081
Weighted average number of common shares used in the calculation of diluted earnings per share	104,293,961	103,451,909	103,410,738	103,934,711

[2] For the three and six months ended June 30, 2019, the average market price of the Company's common shares exceeded the exercise price of certain granted share purchase options and had a dilutive effect on earnings per share. For the three and six months ended June 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 per share.

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

7. 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:

	June 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	$ -	$ 2	$ 73
Non-current	-	97	-	-	97
Derivative instruments liabilities:					
Current	(19)	(80)	(18)	-	(117)
Non-current	(22)	(103)	(88)	-	(213)
Net fair value	$ (40)	$ (16)	$ (106)	$ 2	$ (160)
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(8)	(14)			
Gigajoules of natural gas		206			
Metric tons of emission allowances		3			
Number of renewable energy credits		(31)			
Interest rate swaps (note 4)			$ 763		
Forward currency sells (U.S. dollars)				$ (54)	
Range of remaining contract terms in years	0.1 to 4.5	0.1 to 13.5	1.3 to 1.4	0.1 to 0.4	

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

7. 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 (loss) income and net income are:

	Three months ended June 30, 2019		Three months ended June 30, 2018	
	Unrealized (losses) gains	Realized (losses) gains	Unrealized gains	Realized (losses) gains
Energy cash flow hedges	$ (37)	$ (6)	$ 3	$ (13)
Energy and emission allowances non-hedges	50	15	21	10
Interest rate cash flow hedges[1]	(5)	-	2	-
Foreign exchange non-hedges	(6)	6	3	-

[1] Interest rate cash flow hedges of $200 million were settled in the three months ended June 30, 2019 for a total loss of $12 million recognized in other comprehensive (loss) income and to be reclassified to net income in future periods within the associated net finance expense pertaining to the hedged financing.

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

7. Derivative financial instruments and hedge accounting, continued:

	Six months ended June 30, 2019		Six months ended June 30, 2018	
	Unrealized (losses) gains	Realized (losses) gains	Unrealized (losses) gains	Realized (losses) gains
Energy cash flow hedges	$ (55)	$ (26)	$ (26)	$ (2)
Energy and emission allowances non-hedges	88	15	26	32
Interest rate cash flow hedges[2]	(12)	(1)	2	-
Foreign exchange non-hedges	(9)	6	(27)	33

[2] Interest rate cash flow hedges of $450 million were settled in the six months ended June 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 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 for the three and six months ended June 30, 2019 and 2018:

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	2019	2018
Revenues	$ (11)	$ 3	$ (76)	$ 14
Energy purchases and fuel	70	15	153	42
Foreign exchange gain (loss)	-	3	(3)	6
Net finance expense	-	-	(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 six months ended June 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 six months ended June 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 income in the following periods:

	June 30, 2019
Within one year	$ (24)
Between 1 – 5 years	(19)
After more than 5 years	2
	$ (41)

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

8. Leases:

Right-of-use assets

	Land	Offices	Equipment	Total
Balance, January 1, 2019	$ 51	$ 28	$ 20	$ 99
Depreciation	(2)	(1)	(1)	(4)
Balance, June 30, 2019	$ 49	$ 27	$ 19	$ 95

Lease Liabilities

Contractual undiscounted cash flows for lease liabilities:

As at June 30	2019
Within one year	$ 10
Between one and five years	35
More than five years	111
Total	$ 156

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

	Three months ended June 30, 2019	Six months ended June 30, 2019
Interest on lease liabilities	$ 2	$ 3
Variable lease payments not included in the measurement of lease liabilities	1	2

As at June 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 June 30, 2019, the cost of such property, plant and equipment was $2,041 million (December 31, 2018 - $2,006 million), less accumulated depreciation of $490 million (December 31, 2018 - $433 million).

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

As at June 30	2019
2019	$ 131
2020	169
2021	125
2022	118
2023	47
Thereafter	97
Total	$ 687

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

9. 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%.

10. Share capital:

	Dividends declared							
	For the three months ended June 30,				For the six months ended June 30,			
	2019		2018		2019		2018	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.4475	$ 48	$ 0.4175	$ 43	$ 0.8950	$ 94	$ 0.8350	$ 86
Preference								
Series 1	0.1913	1	0.1913	1	0.3825	2	0.3825	2
Series 3	0.3408	2	0.2875	2	0.6816	4	0.5750	4
Series 5	0.3274	3	0.2813	2	0.6548	6	0.5626	4
Series 7	0.3750	3	0.3750	3	0.7500	6	0.7500	6
Series 9	0.3594	2	0.3594	2	0.7188	4	0.7188	4
Series 11	0.1772	1	-	-	0.1772	1	-	-

	Dividends paid [1]							
	For the three months ended June 30,				For the six months ended June 30,			
	2019		2018		2019		2018	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.4475	$ 45	$ 0.4175	$ 44	$ 0.8950	$ 91	$ 0.8350	$ 87

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

During the three and six months ended June 30, 2019, the Company purchased and cancelled 1,500 and 383,412 of its outstanding common shares at an average exercise price of $30.29 and $26.48 per share for nominal proceeds and $10 million, respectively (three and six months ended June 30, 2018 – 1,013,938 and 1,726,938 for $25 million and $42 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)

10. 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.

11. Financial instruments:

Fair values

Details of the fair values of the Company's derivative instruments are described in note 7.

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:

		June 30, 2019		December 31, 2018	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Government grant receivable[1]	Level 2	519	481	511	505
Loans and borrowings[1]	Level 2	3,279	3,019	2,647	2,645

[1] Includes current portion.

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

11. 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 six months ended June 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.

	June 30, 2019			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 145	$ 25	$ 170
Derivative financial instruments liabilities	-	(319)	(11)	(330)

	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)

11. Financial instruments, continued:

Fair value hierarchy, continued

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

In addition, as at June 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:

	June 30, 2019	December 31, 2018
REC pricing (per certificate) – Thermal	$0.80	$1.09
REC pricing (per certificate) – Solar	$212.70 to $301.20	$221.55 to $395.64
Power pricing (per MWh) – Wind	$13.16 to $60.00	$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:

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

11. Financial instruments, continued:

Fair value hierarchy, continued

Continuity of Level 3 balances, continued

	Six months ended June 30, 2019	Year ended December 31, 2018
As at January 1[3]	$ (28)	$ 30
Unrealized and realized gains (losses) included in net income[4]	41	(55)
Transfers[5]	-	(5)
Foreign exchange gain	1	2
As at end of period	$ 14	$ (28)
Total unrealized gains (losses) for the period included in net income[4]	$ 41	$ (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)

12. 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 June 30, 2019				Three months ended June 30, 2018 (note 3)			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 211	$ 123	$ -	$ 334	$ 225	$ 77	$ -	$ 302
Revenues - inter-area	6	4	(10)	-	(1)	3	(2)	-
Other income	16	16	-	32	15	52	-	67
Total revenues and other income	$ 233	$ 143	$ (10)	$ 366	$ 239	$ 132	$ (2)	$ 369

	Six months ended June 30, 2019				Six months ended June 30, 2018 (note 3)			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 469	$ 230	$ -	$ 699	$ 449	$ 139	$ -	$ 588
Revenues - inter-area	20	(10)	(10)	-	4	9	(13)	-
Other income	33	31	-	64	30	64	-	94
Total revenues and other income	$ 522	$ 251	$ (10)	$ 763	$ 483	$ 212	$ (13)	$ 682

	As at June 30, 2019			As at December 31, 2018 (note 3)		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 4,845	$ 1,441	$ 6,286	$ 3,947	$ 1,409	$ 5,356
Right-of-use assets (note 8)	59	36	95	-	-	-
Intangible assets	737	188	925	249	224	473
Goodwill	35	-	35	35	-	35
Other assets	58	-	58	65	1	66
	$ 5,734	$ 1,665	$ 7,399	$ 4,296	$ 1,634	$ 5,930

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

12. 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 June 30, 2019						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 143	$ 2	$ 47	$ 36	$ 228	$ 94	$ 322
Emission credit revenues	5	-	-	2	7	5	12
Total revenues[1]	$ 148	$ 2	$ 47	$ 38	$ 235	$ 99	$ 334

	Six months ended June 30, 2019						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 336	$ 3	$ 84	$ 88	$ 511	$ 162	$ 673
Emission credit revenues	12	-	-	4	16	10	26
Total revenues[1]	$ 348	$ 3	$ 84	$ 92	$ 527	$ 172	$ 699

[1] Included within trade and other receivables, as at June 30, 2019, were amounts related to contracts with customers of $109 million.

	Three months ended June 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	$ 3	$ 31	$ 31	$ 205	$ 86	$ 291
Emission credit revenues	5	-	-	2	7	4	11
Total revenues[2]	$ 145	$ 3	$ 31	$ 33	$ 212	$ 90	$ 302

	Six months ended June 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	$ 244	$ 4	$ 71	$ 58	$ 377	$ 178	$ 555
Emission credit revenues	13	-	-	4	17	16	33
Total revenues[2]	$ 257	$ 4	$ 71	$ 62	$ 394	$ 194	$ 588

[2] Included within trade and other receivables, as at June 30, 2018, were amounts related to contracts with customers of $94 million.

13. Comparative figures:

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

14. Subsequent event:

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.