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RESPONSIBLE ENERGY FOR TOMORROW

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Capital Power reports strong third quarter 2020 results highlighted by 10-year contract extension for Decatur Energy

Continued growth in contracted renewables with new solar projects in the U.S.

EDMONTON, Alberta – November 2, 2020 – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended September 30, 2020.

Highlights

- Generated net cash flows from operating activities of $258 million and adjusted funds from operations (AFFO) of $221 million in the third quarter of 2020
- Generated net income of $106 million and adjusted EBITDA of $284 million in the third quarter of 2020
- Executed a 10-year contract extension for Decatur Energy through to 2032
- Executed 20-year contracts for three solar development projects in North Carolina that will add 160 megawatts in 2022

"Capital Power delivered financial and operational results in the third quarter of 2020 that were in line with management's expectations thanks to the efforts of our employees who work at our facilities and those who continue to work remotely during the COVID-19 pandemic," said Brian Vaasjo, President and CEO of Capital Power. "Third quarter results benefitted from excellent operating performance across the entire fleet with average facility availability of 98% and a solid contribution from our trading desk that captured an average realized Alberta power price of $59 per megawatt hour (MWh) in the third quarter that was 34% higher than the average spot price of $44 per MWh. Based on our forecast for the remainder of the year, we are on track to generate AFFO near the midpoint and adjusted EBITDA above the midpoint of our $500 million to $550 million and $935 million to $985 million annual guidance ranges for 2020, respectively."

"One of the highlights in the third quarter was the 10-year contract extension for Decatur Energy out to 2032. With our upgrades to the combustion turbines since its acquisition in 2017, the expected financial contributions from the contract extension will add significant value both in the remaining years of the existing contract and beyond the current contract expiry in 2022. The contract extension also validates our acquisition strategy of acquiring mid-life contracted gas assets that have a positive outlook for re-contracting and have value beyond the current contract term," added Mr. Vaasjo.

"In October, we signed 20-year power purchase agreements for three solar development projects in North Carolina totaling 160 megawatts of capacity," continued Mr. Vaasjo. "With the Whitla Wind 2 and 3 and Strathmore Solar projects in advanced development in Alberta, we will be adding approximately 350 megawatts of renewable capacity to our fleet by the end of 2022 representing another step toward our goal of being net carbon neutral before 2050. With their 20-year contract terms, the North Carolina solar projects will also strengthen our contracted cash flows while increasing the average remaining contract life of our contracted assets."

Operational and Financial Highlights [1] (unaudited)	**Three months ended September 30**				**Nine months ended September 30**			
(millions of dollars except per share and operational amounts)		**2020**		**2019**		**2020**		**2019**
Electricity generation (Gigawatt hours)		6,327		6,808		17,361		18,090
Generation facility availability		98%		96%		94%		95%
Revenues and other income [3]	$	453	$	517	$	1,421	$	1,280
Adjusted EBITDA [2, 3]	$	284	$	284	$	735	$	677
Net income (loss) [3]	$	106	$	(228)	$	129	$	(62)
Net income (loss) attributable to shareholders of the Company [3]	$	108	$	(226)	$	133	$	(57)
Basic earnings (loss) per share [3]	$	0.89	$	(2.25)	$	0.87	$	(0.90)
Diluted earnings (loss) per share [3]	$	0.89	$	(2.25)	$	0.87	$	(0.90)
Normalized earnings attributable to common shareholders [2,3]	$	69	$	64	$	115	$	109
Normalized earnings per share [2, 3]	$	0.66	$	0.60	$	1.09	$	1.05
Net cash flows from operating activities	$	258	$	209	$	452	$	519
Adjusted funds from operations [2]	$	221	$	225	$	436	$	427
Adjusted funds from operations per share [2]	$	2.10	$	2.11	$	4.14	$	4.11
Purchase of property, plant and equipment and other assets	$	50	$	193	$	236	$	523
Dividends per common share, declared	$	0.5125	$	0.4800	$	1.4725	$	1.3750

1 The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the unaudited condensed interim consolidated financial statements for the nine months ended September 30, 2020.

2 Earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from 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, AFFO and AFFO 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 Includes depreciation and amortization for the three months ended September 30, 2020 and 2019 of $115 million and $135 million, respectively, and for the nine months ended September 30, 2020 and 2019 of $369 million (including the $13 million write-off of capital costs related to the discontinuation of the Genesee 4 and 5 project and $3 million related to the termination of East Windsor steam contract) and $355 million, respectively. Forecasted depreciation and amortization for the remainder of 2020 is $119 million.

Significant Events

Wind facility long-term service agreement extensions and Whitla Wind 2 and 3 turbine supply

In late April 2020, the Company signed agreements with Vestas setting the terms for 10-year long-term service agreement (LTSA) extensions for the maintenance of nine of the Company's wind facilities and the supply of turbines for the 97 megawatts (MW) of capacity of Whitla Wind 2 with commercial operations expected in 2021. The agreement for the supply of turbines for Whitla Wind 2 contained an option to supply turbines for Whitla Wind 3, which the Company exercised in the second quarter of 2020.

The agreement for the 10-year extension on the series of LTSAs with Vestas covers a wider scope of services for all of our Vestas-equipped wind facilities while reducing costs by an estimated 26% compared to current service and maintenance agreements. The new LTSAs were executed in October 2020 and will take effect between 2021 and 2023. The Company expects to realize ongoing annual savings on the Company's wind facilities covered under these LTSAs, which would increase adjusted EBITDA and AFFO by approximately $8 million and $6 million per year, respectively. Additionally, the LTSA extensions include provisions intended to identify and encourage potential indigenous training, employment and economic opportunities at Canadian facilities.

Extension of Decatur Energy tolling agreement

In August 2020, the Company executed a 10-year tolling agreement extension through December 2032 for Decatur Energy with the current counterparty. Decatur Energy is a natural gas-fired combined cycle facility located in Decatur, Alabama that began commercial operations in 2002. Decatur Energy sells capacity and energy to a regional entity with an A-rated credit rating under a tolling agreement with an original term of 10 years that was to expire in December 2022.

Since the acquisition in June 2017, Capital Power has been upgrading Decatur Energy's combustion turbines to increase capacity, improve the facility's heat rate and fuel efficiency and maintain reliability. To date, two of three combustion turbines have been upgraded adding approximately 60 megawatts of additional capacity. The third combustion turbine is expected to be upgraded in 2021 adding approximately 30 MW.

Under the terms of the extension, Decatur Energy will receive payments for 34 MW of additional capacity immediately and will receive capacity payments on up to an additional 79 MW upon execution of an updated interconnection agreement that is expected to be finalized in 2021.

Strathmore Solar project proceeding

On July 30, 2020, the Company announced that, subject to successful permitting and regulatory approvals, it is moving forward with the Strathmore Solar project, in Strathmore Alberta, which will add 40.5 MW in early 2022. This will be the Company's first solar project in Canada and will have an expected capital cost in the range of $50 million to $55 million.

Strathmore Solar will generate carbon credits that can be used to hedge against Capital Power's carbon compliance costs from its Alberta thermal generation facilities. The Company expects a portion of the output from Strathmore Solar to be sold under renewable offtake contracts and is actively pursuing contracting opportunities. The Company expects average annual adjusted EBITDA and AFFO to be approximately $5 million and $5 million, respectively, over the first five years of the project.

Executive appointments

On July 30, 2020, Capital Power and the Board of Directors announced the following executive position appointments effective immediately:

- Kate Chisholm, Senior Vice President Planning and Stakeholder Relations and Chief Sustainability Officer,
- Bryan DeNeve, Senior Vice President Business Development and Commercial Services,
- Sandra Haskins, Senior Vice President Finance and Chief Financial Officer,
- Chris Kopecky, Senior Vice President and Chief Legal Officer, and
- Jacquie Pylypiuk, Senior Vice President People, Culture and Technology.

Darcy Trufyn continues to serve as the Senior Vice President Operations, Engineering and Construction. Mark Zimmerman, who previously served as the Senior Vice President, Corporate Development and Commercial Services, stepped down from his role effective July 30, 2020.

Reinstatement of Dividend Reinvestment Plan

On July 30, 2020, the Company reinstated its Dividend Reinvestment Plan (the Plan) which was previously suspended on June 30, 2015 (the suspension). Eligible shareholders may elect to participate in the Plan commencing with the Company's third quarter 2020 cash dividend. The reinstated Plan will provide eligible shareholders with an alternative to receiving their quarterly cash dividends. Under the Plan, eligible shareholders may elect to efficiently and cost-effectively accumulate additional shares in the Company by reinvesting their quarterly cash dividends on the applicable dividend payment date in new shares issued from treasury. The new shares will be issued at a discount of 3% to the average closing price on the Toronto Stock Exchange for the ten trading days immediately preceding the applicable Dividend Payment Date. Participation in the Plan is optional. Those shareholders who do not enroll in the Plan will still be entitled to receive their quarterly cash dividends. Shareholders that were enrolled in the Plan upon suspension, and remain enrolled with the Plan administrator, will automatically resume participation in the Plan.

Dividend increase

On July 29, 2020, the Company's Board of Directors approved an increase of 6.8% in the annual dividend for holders of its common shares, from $1.92 per common share to $2.05 per common share. This increased common share dividend will commence with the third quarter 2020 quarterly dividend payment on October 30, 2020 to shareholders of record at the close of business on September 30, 2020.

Whitla Wind 3 project proceeding

In June 2020, the Company announced that, subject to successful permitting and receipt of regulatory approvals, it is moving forward with the third phase of the Whitla Wind facility which will add 54 MW in late 2021. Capital Power will leverage its construction experience from Whitla Wind 1, to deliver Whitla Wind 3 with an expected capital cost of $92 million.

Whitla Wind 3 will generate carbon credits that can be used to hedge against Capital Power's carbon compliance costs from its Alberta thermal generation facilities. Both construction activities and discussions around renewable offtake contracts for Whitla Wind 3 are expected to occur concurrently with those of Whitla Wind 2 and the Company is in active discussions with commercial and industrial customers for renewable offtake contracts for Whitla Wind 2 and 3.

Acquisition of Buckthorn Wind

On April 1, 2020, the Company acquired a 100% ownership interest in Buckthorn Wind, a 101 MW wind facility, from co-sellers John Laing Investments and Clearway Renew LLC, a subsidiary of Clearway Energy Group LLC. The purchase price consisted of (i) $84 million (US$60 million) in total cash consideration, including working capital and other closing adjustments, (ii) the assumption of tax equity financing of $103 million (US$73 million) and (iii) contingent consideration valued at nil. Contingent consideration, to a maximum of US$8 million, would become payable in the future if certain market outcomes lead to Buckthorn Wind exceeding agreed upon thresholds. At this time, the Company considers the likelihood of contingent consideration payment to be low, resulting in no value being ascribed to the contingent consideration in the purchase price allocation.

Buckthorn Wind is located in Erath County, approximately 60 miles south of Dallas, Texas and began commercial operations in January 2018. It operates in the liquid Electric Reliability Council of Texas (ERCOT) North region between most of the wind generation in ERCOT-West and the Dallas load center. The ERCOT North region has strong fundamentals with a high likelihood of baseload generation retirements and is one of the fastest growing regions in the United States.

Buckthorn Wind has a 15-year weighted average contract life remaining with two offtake arrangements including one with JPMorgan Chase Bank involving a 20-year contract for differences (CfD) for 55% of the generation output, and a 13-year financial hedge for the remaining 45% of the output. The long-term contracts strengthen the Company's contracted cash flow profile while expanding our renewables portfolio.

Buckthorn Wind has a tax equity investor (TEI) where the TEI receives the majority of the cash flows prior to the date on which the TEI reaches the agreed upon target rate of return (the flip date). The flip date is expected to occur in the late 2020s. Prior to the flip date, the Company expects average annual adjusted EBITDA and AFFO to be approximately $18 million (US$14 million) and $1 million (US$1 million), respectively. After the flip date during the CfD, the average annual adjusted EBITDA and AFFO are expected to be approximately $9 million (US$8 million) and $6 million (US$5 million), respectively.

Cardinal Point Wind begins commercial operations

On March 16, 2020, Cardinal Point Wind, a 150 MW facility in the McDonough and Warren Counties, Illinois, began commercial operations. Subsequently, the Company received approximately $221 million (US$157 million) in tax equity financing on March 26, 2020, net of issue costs of $3 million (US$2 million) associated with the financing, from two U.S. financial institutions in exchange for Class A interests of a subsidiary of the Company. The construction of the facility was completed on-schedule and as final costs are incurred during the remainder of 2020, is expected to be within its projected total cost of US$236 million to US$246 million.

Capital Power will operate Cardinal Point Wind under a 12-year fixed price contract with an investment grade U.S. financial institution covering 85% of the facility's output. The expected adjusted EBITDA and AFFO in the first full year of operations are $56 million (US$40 million) and $6 million (US$4 million), respectively.

Discontinuation of the Genesee 4 and 5 project

During the first quarter of 2020, the Company and its partner on the Genesee 4 and 5 project determined that they would no longer be pursuing the project. Arbitration has commenced between the Company and its partner around the costs of exiting the series of agreements previously entered into. As a result of the decision to no longer pursue the project, the Company has determined that $13 million of capital expenditures incurred by the Company were purely related to the development of Genesee 4 and 5. The Company has therefore recorded a write-off of these capital costs during the first quarter of 2020 within depreciation and amortization.

Subsequent Events

20-year contracts for three new solar development projects in North Carolina

In October 2020, the Company executed 20-year power purchase agreements with Duke Energy Carolinas for three solar development projects located in North Carolina totaling 160 MW. The solar projects consist of Hornet Solar (75 MW), Hunter's Cove Solar (50 MW), and Bear Branch Solar (35 MW) (collectively, the "solar projects"). Construction of the solar projects is expected to begin in late 2021 or early 2022 with commercial operations expected in the fourth quarter of 2022 and with expected capital costs of $118 million (US$90 million), $82 million (US$62 million) and $60 million (US$46 million) for the three projects, respectively. Capital Power expects to finance the solar projects using debt and tax equity.

With their 20-year contract terms, the North Carolina solar projects will strengthen our contracted cash flows while increasing the average remaining contract life of our contracted assets. The investment is expected to meet Capital Power's after-tax hurdle rate with the average accretion expected to be neutral to AFFO in the first five years. The solar projects are expected to generate approximately $23 million (US$17 million) of adjusted EBITDA and $5 million (US$4 million) of AFFO annually on average in the first five years.

$350 million medium-term note offering and early redemption of $251 million medium-term notes

On October 1, 2020 the Company closed a public offering of unsecured medium-term notes in the aggregate principal amount of $350 million (the Offering). The notes have a coupon rate of 3.147% and mature on October 1, 2032. The net proceeds of the Offering have been and will be used to repay, redeem or refinance existing indebtedness, including indebtedness under outstanding debt securities or credit facilities, or for general corporate purposes. Included in such repayments is the redemption, on October 9, 2020, of all of the Company's outstanding 5.276% medium-term notes, due November 16, 2020, in the aggregate principal amount of $251 million. The redemption price was an aggregate amount of $258 million, including applicable early redemption premiums, as well as accrued and unpaid interest to and including the day immediately preceding the redemption date.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on November 2, 2020 at 9:00 am (MT) to discuss the third quarter financial results. The conference call dial-in number is:

(855) 327-6838 (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 joint venture interests, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emission credits (adjusted EBITDA), (ii) AFFO, (iii) AFFO 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.

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

(unaudited, $ millions)	**Three months ended**							
	Sep 30 2020	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**
Revenues and other income [2]	453	435	533	683	517	366	397	340
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(144)	(233)	(323)	(309)	(231)	(134)	(167)	(233)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	(31)	9	18	(28)	(8)	(48)	(34)	53
Adjusted EBITDA from joint ventures [1]	6	6	6	6	6	7	6	11
Adjusted EBITDA	**284**	**217**	**234**	**352**	**284**	**191**	**202**	**171**
Depreciation and amortization [2]	(115)	(121)	(133)	(118)	(135)	(122)	(98)	(85)
Unrealized changes in fair value of commodity derivatives and emission credits	31	(9)	(18)	28	8	48	34	(53)
Impairment	-	-	-	-	(401)	-	-	-
Gains on acquisition and disposal transactions	-	-	-	24	-	-	-	159
Foreign exchange gain (loss)	1	3	(9)	-	(1)	-	(4)	6
Net finance expense	(47)	(49)	(44)	(41)	(42)	(37)	(36)	(33)
Finance expense and depreciation expense from joint ventures [1]	(4)	(6)	(13)	(1)	(7)	(7)	(8)	(10)
Income tax (expense) recovery [2]	(44)	(12)	(17)	(63)	66	33	(30)	(19)
Net income (loss)	**106**	**23**	**-**	**181**	**(228)**	**106**	**60**	**136**
Net income (loss) attributable to:								
Non-controlling interests	(2)	-	(2)	(1)	(2)	(2)	(1)	(2)
Shareholders of the Company [2]	108	23	2	182	(226)	108	61	138
Net income (loss)	**106**	**23**	**-**	**181**	**(228)**	**106**	**60**	**136**

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. Fiscal 2018 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

AFFO is a measure of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, the repayment of debt and the payment of common share dividends.

AFFO represents net cash flows from operating activities adjusted to:

- remove timing impacts of cash receipts and payments that may impact period-to-period comparability which include deductions for net finance expense and current income tax expense, the removal of deductions for interest paid and income taxes paid and removing changes in operating working capital,
- include the Company's share of the AFFO of its joint venture interests and exclude distributions received from the Company's joint venture interests which are calculated after the effect of non-operating activity joint venture debt payments,
- include cash from coal compensation that will be received annually,
- remove the tax equity financing project investors' shares of AFFO associated with assets under tax equity financing structures so only the Company's share is reflected in the overall metric,
- deduct sustaining capital expenditures and preferred share dividends, and
- exclude 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.

AFFO per share is determined by applying AFFO 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 AFFO is as follows:

(unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2020	**2019**	**2020**	**2019**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**258**	**209**	**452**	**519**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	39	36	101	83
Realized loss (gain) on settlement of interest rate derivatives	-	-	(1)	19
Change in fair value of derivatives reflected as cash settlement	8	1	26	(36)
Distributions received from joint ventures	(3)	(3)	(8)	(9)
Miscellaneous financing charges paid [1]	1	1	4	4
Income taxes paid	5	2	38	4
Change in non-cash operating working capital	(65)	(3)	(12)	(26)
	(15)	34	148	39
Net finance expense [2]	(35)	(33)	(106)	(90)
Current income tax expense [3]	(10)	(6)	(26)	(7)
Sustaining capital expenditures [4]	(16)	(18)	(50)	(58)
Preferred share dividends paid	(13)	(13)	(39)	(36)
Cash received from coal compensation	50	50	50	50
Remove tax equity interests' respective shares of adjusted funds from operations	(2)	(2)	(6)	(4)
Adjusted funds from operations from joint ventures	4	4	13	14
Adjusted funds from operations	**221**	225	**436**	427
Weighted average number of common shares outstanding (millions)	**105.1**	**106.5**	**105.2**	**104.0**
Adjusted funds from operations per share ($)	**2.10**	**2.11**	**4.14**	**4.11**

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 related to the Genesee 3 and Keephills 3 swap transaction and the disposal of the Company's interest in the K2 Wind joint venture as these amounts are considered investing activities.

4 Includes sustaining capital expenditures net of partner contributions of $1 million and $4 million for the three and nine months ended September 30, 2020, respectively, compared with $2 million and $5 million for the three and nine months ended September 30, 2019, respectively.

Normalized earnings attributable to common shareholders and normalized earnings per share

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

(unaudited, $ millions except per share amounts and number of common shares)	Three months ended							
	Sep 30 2020	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**
Basic earnings (loss) per share ($)[2]	**0.89**	**0.10**	**(0.11)**	**1.61**	**(2.25)**	**0.93**	**0.49**	**1.24**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss) [2]	**108**	**23**	**2**	**182**	**(226)**	**108**	**61**	**138**
Preferred share dividends including Part VI.1 tax	(14)	(13)	(14)	(12)	(14)	(12)	(11)	(11)
Earnings (loss) attributable to common shareholders [2]	94	10	(12)	170	(240)	96	50	127
Unrealized changes in fair value of derivatives [1]	(28)	3	30	(28)	(3)	(30)	(20)	35
Restructuring charges	2	-	-	-	-	-	-	-
Other tax adjustment	1	-	-	-	-	-	-	-
Provision for Line Loss Rule Proceeding (See Contingent Liabilities and Provisions)	-	3	-	4	-	-	-	-
Termination of East Windsor steam contract	-	2	-	-	-	-	-	-
Loss on discontinuation of Genesee 4 and 5 project (see Significant Events)	-	-	10	-	-	-	-	-
Net (gain) loss on Genesee 3 and Keephills 3 swap transaction	-	-	-	(115)	307	-	-	-
Alberta tax rate change	-	-	-	-	-	(51)	-	-
Gain on disposal of joint venture	-	-	-	-	-	-	-	(134)
Asset held for sale accounting treatment of K2 Wind	-	-	-	-	-	-	-	3
Normalized earnings attributable to common shareholders [2]	**69**	**18**	**28**	**31**	**64**	**15**	**30**	**31**
Weighted average number of common shares outstanding (millions)	105.1	105.1	105.4	105.3	106.5	103.6	101.8	102.3
Normalized earnings per share ($)[2]	**0.66**	**0.17**	**0.27**	**0.29**	**0.60**	**0.14**	**0.29**	**0.30**

1 Includes impacts of the interest rate non-hedge held within a joint venture and recorded within loss from joint venture on the Company's condensed interim consolidated statements of income.

2 Fiscal 2018 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) status of the Company's 2020 AFFO and adjusted EBITDA guidance, (ii) forecasted depreciation for the remainder of 2020, (iii) expected timing of commencement of commercial operations of Whitla Wind 2 and 3 and expected capital costs of Whitla Wind 3, (iv) expectations around the Vestas agreements including cost reductions and impacts on adjusted EBITDA and AFFO, (v) the timing of completion of the Decatur Energy combustion turbine upgrades, (vi) expectations around the likelihood of meeting the threshold and paying out contingent consideration related to Buckthorn Wind, (vii) expectations pertaining to the financial impacts of the acquisition of Buckthorn Wind, including the impacts to adjusted EBITDA and AFFO, (viii) the expected timing of when the Buckthorn Wind tax equity investor reaches the agreed upon target rate of return, (ix) expectations pertaining to the financial impacts of Cardinal Point Wind in its first full year of operations, including the impacts to adjusted EBITDA and AFFO, (x) expectations pertaining to Strathmore Solar including timing and costs of construction, expectations around potential contracting and financial impacts including impacts to adjusted EBITDA and AFFO, and (xi) expectations pertaining to the North Carolina solar projects including timing of construction and commercial operations, project costs and impacts on adjusted EBITDA and AFFO.

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: (i) electricity, other energy and carbon prices, (ii) operating and asset development performance, (iii) business prospects (including potential re-contracting opportunities) and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates and (vi) foreign exchange 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, wind capacity factor and performance including maintenance expenditures, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, (viii) ability to realize the anticipated benefits of the Buckthorn Wind acquisition, (ix) limitations inherent in the Company's review of acquired assets, and (x) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's Management's Discussion and Analysis for both the nine months ended September 30, 2020, prepared as of October 30, 2020 and for the year ended December 31, 2019, prepared as of February 21, 2020, 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.

About Capital Power

Capital Power (TSX: CPX) 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 6,500 MW of power generation capacity at 28 facilities across North America. Approximately 350 MW of owned generation capacity is in advanced development in Alberta and North Carolina.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of October 30, 2020, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the nine months ended September 30, 2020, the audited consolidated financial statements and MD&A of Capital Power Corporation for the year ended December 31, 2019, the annual information form of Capital Power Corporation dated February 24, 2020, and the cautionary statements regarding forward-looking information which begin on page 11. In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation together with its subsidiaries.

In this MD&A, financial information for the nine months ended September 30, 2020 and the nine months ended September 30, 2019 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods which were prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors approved this MD&A as of October 30, 2020.

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, adjusted EBITDA 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 phases 2 and 3 of the Whitla Wind project, the Strathmore Solar project (See Significant Events) and the North Carolina solar projects (see Subsequent Events)),
- facility availability and planned outages,
- capital expenditures for facility maintenance and other (sustaining capital, future growth projects, commercial initiatives),
- the financial impacts of the acquisition of Buckthorn Wind (see Significant Events), including the impacts to adjusted EBITDA and adjusted funds from operations,
- the likelihood of meeting the threshold and paying out contingent consideration related to Buckthorn Wind,
- the timing of the Buckthorn Wind tax equity investor reaching the agreed upon target rate of return,
- the final cost and financial impacts of Cardinal Point Wind (see Significant Events) in its first full year of operations, including the impacts to adjusted EBITDA and adjusted funds from operations,
- the timing of completion of the Decatur Energy combustion turbine upgrades and impacts of the Decatur Energy tolling agreement extension to adjusted EBITDA (see Significant Events),
- impacts of the Vestas long-term service agreement (LTSA) extensions (see Significant Events), including cost reductions, impacts on adjusted EBITDA and adjusted funds from operations in the years the executed agreements become effective,
- the financial impacts of the Strathmore Solar project (see Significant Events) and the North Carolina solar projects (see Subsequent Events), including impacts to adjusted EBITDA and adjusted funds from operations,
- the impacts of market designs in the Company's core markets,
- the Line Loss Rule Proceeding including timing of invoicing, participation in applicable regulatory processes, and potential impacts to the Company, and
- the impact of the COVID-19 pandemic and the decline in oil prices.

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, including the anticipated performance of the Buckthorn Wind acquisition and the Cardinal Point Wind, Strathmore Solar and North Carolina solar development projects,
- 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,
- foreign exchange rates,
- assumptions around the Line Loss Rule Proceeding calculations include the estimated adjustment loss factors and invoice timing for the remaining historic period (2006-2013) and recovery from appropriate parties, and
- other matters discussed under the Performance Overview, Outlook and Risks and Risk Management sections.

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 and tax legislation,
- generation facility availability, wind capacity factor and performance including maintenance expenditures,
- 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 Buckthorn Wind acquisition,
- limitations inherent in the Company's review of acquired assets,
- changes in general economic and competitive conditions, and
- risks and uncertainties discussed under the Risks and Risk Management section.

See Risks and Risk Management in the Company's December 31, 2019 annual MD&A and Risks and Risk Management 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 6,500 megawatts (MW) of power generation capacity at 28 facilities across North America. Approximately 350 MW of owned generation capacity is in advanced development in Alberta and North Carolina.

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 2019 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	2020 target	Actual results for the nine months ended September 30, 2020
Facility availability average	93% or greater	94%
Sustaining capital expenditures	$90 to $100 million	$50 million [1]

[1] Includes sustaining capital expenditures net of joint venture contributions of $4 million.

The Company's facility availability averaged 94% which most notably reflected planned outages at Clover Bar Energy Centre, Goreway, Roxboro, Southport, Arlington Valley and Decatur Energy. Unplanned outages also occurred at Genesee, Clover Bar Energy Centre, Joffre, EnPower, Goreway, Arlington Valley and Southport.

Sustaining capital expenditures for the nine months ended September 30, 2020 were lower than target for the year to date primarily due to various budgeted sustaining capital projects which will be incurred later in the year and into 2021. Full year sustaining capital expenditures are expected to be below target mainly due to a deferral of spend to 2021 on various capital projects driven by COVID-19 risk mitigation. Accordingly, facility availability is expected to modestly exceed target in the year.

Disciplined growth

Performance measure	2020 target	Status as at September 30, 2020
Cardinal Point Wind	Completion of Cardinal Point Wind on budget and on time for commercial operations in March 2020.	Construction completed on time in March 2020. Total project costs are expected to be near the low end of target range in the facility's U.S. dollar functional currency (see Liquidity and Capital Resources).
Whitla Wind 2	Advance development of the Whitla Wind 2 project to be on track with budget and the 2021 completion date.	Construction expected to be complete and on budget in the fourth quarter of 2021.
Other growth	$500 million of committed capital.	See Significant Events and Subsequent Events for progress on this target during the year to date, including the advancement of Whitla Wind 3 and Strathmore Solar and the acquisition of Buckthorn Wind. Subsequent to the third quarter of 2020, the Company executed power purchase agreements for three solar development projects located in North Carolina which, in combination with the progress noted above, brought committed capital during 2020 to approximately $590 million.

Financial stability and strength

Performance measure	2020 target	Actual results to September 30, 2020
Adjusted funds from operations [1]	$500 million to $550 million	$436 million
Adjusted EBITDA [1]	$935 million to $985 million	$735 million

[1] 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 2019, the Company provided financial guidance for 2020 adjusted funds from operations in the range of $500 million to $550 million and 2020 adjusted EBITDA in the range of $935 million to $985 million (see Non-GAAP Financial Measures). Based on the actual results for the first nine months of 2020 and the Company's forecast for the remainder of 2020, the Company expects adjusted funds from operations for 2020 to be near the mid-point of the guidance range, excluding the impact of the Line Loss Rule Proceeding (see Contingent Liabilities and Provisions). The impact to adjusted funds from operations of the Line Loss Rule Proceeding in the fourth quarter of 2020 will be $6 million based on the initial invoice received in October 2020. Based on actual results for the first nine months of 2020 and the Company's forecast for the last quarter of 2020, the Company expects adjusted EBITDA to be above the mid-point of the guidance range.

Priorities for the Company in 2020 include supporting our sustainability targets through the development of the Genesee Carbon Conversion Centre and the strategic development of natural gas and renewable assets. This includes the advancement of the dual-fuel capability project at Genesee, re-contracting efforts on the Company's facilities and ongoing development of the Company's wind projects. Buckthorn Wind was acquired on April 1 (see Significant Events) and efficiently integrating Buckthorn Wind will be a priority during the remainder of 2020. Cardinal Point Wind commenced commercial operations during the first quarter of 2020 (see Significant Events) and phase 2 of the Whitla Wind project (Whitla Wind 2) is in advanced development. Additionally, phase 3 of Whitla Wind (Whitla Wind 3) and the Strathmore Solar project will proceed following the completion of permitting later in the year (see Significant Events). The Company also executed power purchase agreements for three solar development projects in North Carolina (see Subsequent Events), bringing other committed growth capital to approximately $590 million in 2020. In August of 2020, the Company executed a 10-year tolling agreement extension through December 2032 for Decatur Energy (see Significant Events). This 10-year extension validates our acquisition strategy of acquiring mid-life contracted natural gas assets that have a positive outlook for re-contracting and have value beyond the current contract term.

In 2020, Capital Power's availability target of 93% reflects major scheduled maintenance outages for Genesee 2, Arlington Valley, Decatur Energy and Southport compared to those scheduled for Genesee 1, Clover Bar Energy Centre, Joffre, Shepard and Decatur Energy in 2019. The scheduled maintenance outage for Genesee 2 has been rescheduled to occur in 2021 driven by COVID-19 risk mitigation.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2021, 2022 and 2023 (all as at September 30, 2020), were:

Alberta commercial portfolio positions and power prices	Full year 2021	Full year 2022	Full year 2023
Percentage of baseload generation sold forward [1]	13%	18%	12%
Contracted price [2]	High-$50	Low-$50	Low-$50
Forward Alberta pool prices	$52	$52	$51

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 2020 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 2019, the Company confirmed its 7% annual dividend growth guidance for 2020 and 2021 and announced a 5% dividend growth guidance for 2022. 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.

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 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 (AFFO), (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 (loss) is as follows:

(unaudited, $ millions)	Three months ended							
	Sep 30 2020	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**
Revenues and other income [2]	453	435	533	683	517	366	397	340
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(144)	(233)	(323)	(309)	(231)	(134)	(167)	(233)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	(31)	9	18	(28)	(8)	(48)	(34)	53
Adjusted EBITDA from joint ventures [1]	6	6	6	6	6	7	6	11
Adjusted EBITDA	**284**	**217**	**234**	**352**	**284**	**191**	**202**	**171**
Depreciation and amortization [2]	(115)	(121)	(133)	(118)	(135)	(122)	(98)	(85)
Unrealized changes in fair value of commodity derivatives and emission credits	31	(9)	(18)	28	8	48	34	(53)
Impairment	-	-	-	-	(401)	-	-	-
Gains on acquisition and disposal transactions	-	-	-	24	-	-	-	159
Foreign exchange gain (loss)	1	3	(9)	-	(1)	-	(4)	6
Net finance expense	(47)	(49)	(44)	(41)	(42)	(37)	(36)	(33)
Finance expense and depreciation expense from joint ventures [1]	(4)	(6)	(13)	(1)	(7)	(7)	(8)	(10)
Income tax (expense) recovery [2]	(44)	(12)	(17)	(63)	66	33	(30)	(19)
Net income (loss)	**106**	**23**	**-**	**181**	**(228)**	**106**	**60**	**136**
Net income (loss) attributable to:								
Non-controlling interests	(2)	-	(2)	(1)	(2)	(2)	(1)	(2)
Shareholders of the Company [2]	108	23	2	182	(226)	108	61	138
Net income (loss)	**106**	**23**	**-**	**181**	**(228)**	**106**	**60**	**136**

[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] Fiscal 2018 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

AFFO is a measure of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, the repayment of debt and the payment of common share dividends.

AFFO represents net cash flows from operating activities adjusted to:

- remove timing impacts of cash receipts and payments that may impact period-to-period comparability which include deductions for net finance expense and current income tax expense, the removal of deductions for interest paid and income taxes paid and removing changes in operating working capital,
- include the Company's share of the AFFO of its joint venture interests and exclude distributions received from the Company's joint venture interests which are calculated after the effect of non-operating activity joint venture debt payments,
- include cash from coal compensation that will be received annually,
- remove the tax equity financing project investors' shares of adjusted funds from operations associated with assets under tax equity financing structures so only the Company's share is reflected in the overall metric,
- deduct sustaining capital expenditures and preferred share dividends, and
- exclude 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.

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

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

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2020	**2019**	**2020**	**2019**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**258**	**209**	**452**	**519**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	39	36	101	83
Realized (gain) loss on settlement of interest rate derivatives	-	-	(1)	19
Change in fair value of derivatives reflected as cash settlement	8	1	26	(36)
Distributions received from joint ventures	(3)	(3)	(8)	(9)
Miscellaneous financing charges paid [1]	1	1	4	4
Income taxes paid	5	2	38	4
Change in non-cash operating working capital	(65)	(3)	(12)	(26)
	(15)	34	148	39
Net finance expense [2]	(35)	(33)	(106)	(90)
Current income tax expense [3]	(10)	(6)	(26)	(7)
Sustaining capital expenditures [4]	(16)	(18)	(50)	(58)
Preferred share dividends paid	(13)	(13)	(39)	(36)
Cash received from coal compensation	50	50	50	50
Remove tax equity interests' respective shares of adjusted funds from operations	(2)	(2)	(6)	(4)
Adjusted funds from operations from joint ventures	4	4	13	14
Adjusted funds from operations	**221**	**225**	**436**	**427**
Weighted average number of common shares outstanding (millions)	**105.1**	**106.5**	**105.2**	**104.0**
Adjusted funds from operations per share ($)	**2.10**	**2.11**	**4.14**	**4.11**

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 related to the Genesee 3 and Keephills 3 swap transaction and the disposal of the Company's interest in the K2 Wind joint venture as these amounts are considered investing activities.

4 Includes sustaining capital expenditures net of partner contributions of $1 million and $4 million for the three and nine months ended September 30, 2020, respectively, compared with $2 million and $5 million for the three and nine months ended September 30, 2019, respectively.

Normalized earnings attributable to common shareholders and normalized earnings per share

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

(unaudited, $ millions except per share amounts and number of common shares)	Three months ended							
	Sep 30 2020	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**
Basic earnings (loss) per share ($)[2]	**0.89**	**0.10**	**(0.11)**	**1.61**	**(2.25)**	**0.93**	**0.49**	**1.24**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss) [2]	**108**	**23**	**2**	**182**	**(226)**	**108**	**61**	**138**
Preferred share dividends including Part VI.1 tax	(14)	(13)	(14)	(12)	(14)	(12)	(11)	(11)
Earnings (loss) attributable to common shareholders [2]	94	10	(12)	170	(240)	96	50	127
Unrealized changes in fair value of derivatives [1]	(28)	3	30	(28)	(3)	(30)	(20)	35
Restructuring charges	2	-	-	-	-	-	-	-
Other tax adjustment	1	-	-	-	-	-	-	-
Provision for Line Loss Rule Proceeding (See Contingent Liabilities and Provisions)	-	3	-	4	-	-	-	-
Termination of East Windsor steam contract	-	2	-	-	-	-	-	-
Loss on discontinuation of Genesee 4 and 5 project (see Significant Events)	-	-	10	-	-	-	-	-
Net (gain) loss on Genesee 3 and Keephills 3 swap transaction	-	-	-	(115)	307	-	-	-
Alberta tax rate change	-	-	-	-	-	(51)	-	-
Gain on disposal of joint venture	-	-	-	-	-	-	-	(134)
Asset held for sale accounting treatment of K2 Wind	-	-	-	-	-	-	-	3
Normalized earnings attributable to common shareholders [2]	**69**	**18**	**28**	**31**	**64**	**15**	**30**	**31**
Weighted average number of common shares outstanding (millions)	105.1	105.1	105.4	105.3	106.5	103.6	101.8	102.3
Normalized earnings per share ($)[2]	**0.66**	**0.17**	**0.27**	**0.29**	**0.60**	**0.14**	**0.29**	**0.30**

1 Includes impacts of the interest rate non-hedge held within a joint venture and recorded within loss from joint venture on the Company's condensed interim consolidated statements of income.

2 Fiscal 2018 quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16.

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Revenues and other income	453	517	1,421	1,280
Adjusted EBITDA [1]	284	284	735	677
Net income (loss)	106	(228)	129	(62)
Net income (loss) attributable to shareholders of the Company	108	(226)	133	(57)
Normalized earnings attributable to common shareholders [1]	69	64	115	109
Basic earnings (loss) per share ($)	0.89	(2.25)	0.87	(0.90)
Diluted earnings (loss) per share ($) [2]	0.89	(2.25)	0.87	(0.90)
Normalized earnings per share ($) [1]	0.66	0.60	1.09	1.05
Net cash flows from operating activities	258	209	452	519
Adjusted funds from operations [1]	221	225	436	427
Adjusted funds from operations per share ($) [1]	2.10	2.11	4.14	4.11
Purchase of property, plant and equipment and other assets	50	193	236	523
Dividends per common share, declared ($)	0.5125	0.4800	1.4725	1.3750
Dividends per Series 1 preferred share, declared ($)	0.1913	0.1913	0.5738	0.5738
Dividends per Series 3 preferred share, declared ($)	0.3408	0.3408	1.0224	1.0224
Dividends per Series 5 preferred share, declared ($)	0.3274	0.3274	0.9821	0.9821
Dividends per Series 7 preferred share, declared ($)	0.3750	0.3750	1.1250	1.1250
Dividends per Series 9 preferred share, declared ($)	0.3594	0.3594	1.0781	1.0781
Dividends per Series 11 preferred share, declared ($)	0.3594	0.3594	1.0781	0.5366

	As at	
	September 30, 2020	December 31, 2019
Loans and borrowings including current portion	3,422	3,413
Total assets	8,905	8,630

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 (loss) per share was calculated after giving effect to outstanding share purchase options.

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 (loss) per share were driven by the same factors as net income which are discussed in Consolidated Net Income and Results of Operations and the changes from period to period in the weighted average number of common shares outstanding. The changes in normalized earnings per share and normalized earnings attributable to common shareholders were affected by the same drivers as basic earnings (loss) per share, but also the adjustments between earnings (loss) 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. AFFO for the three months ended September 30, 2020 was lower than the corresponding period in 2019 primarily due to lower Arlington Valley AFFO driven by the factors described in Consolidated Net Income and Results of Operations, higher current income tax expense and higher net finance expense. These factors were largely offset by higher AFFO from the commissioning of Whitla Wind 1 in the fourth quarter of 2019, the commissioning of Cardinal Point Wind in the first quarter of 2020 and the acquisition of Buckthorn Wind in April of 2020, lower sustaining capital expenditures at various facilities and higher margins earned on power and natural gas portfolio optimization activities. On a year-to-date basis, higher AFFO further reflects the acquisition of Goreway in the second quarter of 2019 and higher AFFO from Genesee 1 and 2 driven by fewer outage hours in 2020 as compared to 2019. This increase was partially offset by the quarterly impacts above, lower AFFO resulting from lower margins earned on trading of emission credits, and higher preferred share dividends in the nine months ended September 30, 2020. Current income tax expense increases impacting AFFO were driven by current tax expenses on Goreway earnings for the nine months ended September 30, 2020, as well as higher current tax recoveries in 2019 with Whitla Wind 1 commencing commercial operations in 2019.

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

SIGNIFICANT EVENTS

Wind facility long-term service agreement extensions and Whitla Wind 2 and 3 turbine supply

In late April 2020, the Company signed agreements with Vestas setting the terms for 10-year LTSA extensions for the maintenance of nine of the Company's wind facilities and the supply of turbines for the 97 MW of capacity of Whitla Wind 2 with commercial operations expected in 2021. The agreement for the supply of turbines for Whitla Wind 2 contained an option to supply turbines for Whitla Wind 3, which the Company exercised in the second quarter of 2020.

The agreement for the 10-year extension on the series of LTSAs with Vestas covers a wider scope of services for all of our Vestas-equipped wind facilities while reducing costs by an estimated 26% compared to current service and maintenance agreements. The new LTSAs were executed in October 2020 and will take effect between 2021 and 2023. The Company expects to realize ongoing annual savings on the Company's wind facilities covered under these LTSAs, which would increase adjusted EBITDA and AFFO by approximately $8 million and $6 million per year, respectively. Additionally, the LTSA extensions include provisions intended to identify and encourage potential indigenous training, employment and economic opportunities at Canadian facilities.

Extension of Decatur Energy tolling agreement

In August 2020, the Company executed a 10-year tolling agreement extension through December 2032 for Decatur Energy with the current counterparty. Decatur Energy is a natural gas-fired combined cycle facility located in Decatur, Alabama that began commercial operations in 2002. Decatur Energy sells capacity and energy to a regional entity with an A-rated credit rating under a tolling agreement with an original term of 10 years that was to expire in December 2022.

Since the acquisition in June 2017, Capital Power has been upgrading Decatur Energy's combustion turbines to increase capacity, improve the facility's heat rate and fuel efficiency and maintain reliability. To date, two of three combustion turbines have been upgraded adding approximately 60 MW of additional capacity. The third combustion turbine is expected to be upgraded in 2021 adding approximately 30 MW.

Under the terms of the extension, Decatur Energy will receive payments for 34 MW of additional capacity immediately and will receive capacity payments on up to an additional 79 MW upon execution of an updated interconnection agreement that is expected to be finalized in 2021. As a result, adjusted EBITDA is expected to increase by $11 million (US$8 million) in 2021 and $27 million (US$20 million) in 2022. In 2023, the first year of the additional 10-year term, adjusted EBITDA is expected to be $73 million (US$54 million) per year and then decline by approximately 4% on average per annum over the term.

Strathmore Solar project proceeding

On July 30, 2020, the Company announced that, subject to successful permitting and regulatory approvals, it is moving forward with the Strathmore Solar project, in Strathmore Alberta, which will add 40.5 MW in early 2022. This will be the Company's first solar project in Canada and will have an expected capital cost in the range of $50 million to $55 million.

Strathmore Solar will generate carbon credits that can be used to hedge against Capital Power's carbon compliance costs from its Alberta thermal generation facilities. The Company expects a portion of the output from Strathmore Solar to be sold under renewable offtake contracts and is actively pursuing contracting opportunities. The Company expects average annual adjusted EBITDA and AFFO to be approximately $5 million and $5 million, respectively, over the first five years of the project.

Executive appointments

On July 30, 2020, Capital Power and the Board of Directors announced the following executive position appointments effective immediately:

- Kate Chisholm, Senior Vice President Planning and Stakeholder Relations and Chief Sustainability Officer,
- Bryan DeNeve, Senior Vice President Business Development and Commercial Services,
- Sandra Haskins, Senior Vice President Finance and Chief Financial Officer,
- Chris Kopecky, Senior Vice President and Chief Legal Officer, and
- Jacquie Pylypiuk, Senior Vice President People, Culture and Technology.

Darcy Trufyn continues to serve as the Senior Vice President Operations, Engineering and Construction. Mark Zimmerman, who previously served as the Senior Vice President, Corporate Development and Commercial Services, stepped down from his role effective July 30, 2020.

Reinstatement of Dividend Reinvestment Plan

On July 30, 2020, the Company reinstated its Dividend Reinvestment Plan (the Plan), which was previously suspended on June 30, 2015 (the suspension). Eligible shareholders may elect to participate in the Plan commencing with the Company's third quarter 2020 cash dividend. The reinstated Plan will provide eligible shareholders with an alternative to receiving their quarterly cash dividends. Under the Plan, eligible shareholders may elect to efficiently and cost-effectively accumulate additional shares in the Company by reinvesting their quarterly cash dividends on the applicable dividend payment date in new shares issued from treasury. The new shares will be issued at a discount of 3% to the average closing price on the Toronto Stock Exchange for the ten trading days immediately preceding the applicable Dividend Payment Date. Participation in the Plan is optional. Those shareholders who do not enroll in the Plan will still be entitled to receive their quarterly cash dividends. Shareholders that were enrolled in the Plan upon suspension, and remain enrolled with the Plan administrator, will automatically resume participation in the Plan.

Dividend increase

On July 29, 2020, the Company's Board of Directors approved an increase of 6.8% in the annual dividend for holders of its common shares, from $1.92 per common share to $2.05 per common share. This increased common share dividend will commence with the third quarter 2020 quarterly dividend payment on October 30, 2020 to shareholders of record at the close of business on September 30, 2020.

Whitla Wind 3 project proceeding

In June 2020, the Company announced that, subject to successful permitting and receipt of regulatory approvals, it is moving forward with the third phase of the Whitla Wind facility which will add 54 MW in late 2021. Capital Power will leverage its construction experience from Whitla Wind 1, to deliver Whitla Wind 3 with an expected capital cost of $92 million.

Whitla Wind 3 will generate carbon credits that can be used to hedge against Capital Power's carbon compliance costs from its Alberta thermal generation facilities. Both construction activities and discussions around renewable offtake contracts for Whitla Wind 3 are expected to occur concurrently with those of Whitla Wind 2 and the Company is in active discussions with commercial and industrial customers for renewable offtake contracts for Whitla Wind 2 and 3.

Acquisition of Buckthorn Wind

On April 1, 2020, the Company acquired a 100% ownership interest in Buckthorn Wind, a 101 MW wind facility, from co-sellers John Laing Investments and Clearway Renew LLC, a subsidiary of Clearway Energy Group LLC. The purchase price consisted of (i) $84 million (US$60 million) in total cash consideration, including working capital and other closing adjustments, (ii) the assumption of tax equity financing of $103 million (US$73 million) and (iii) contingent consideration valued at nil. Contingent consideration, to a maximum of US$8 million, would become payable in the future if certain market outcomes lead to Buckthorn Wind exceeding agreed upon thresholds. At this time, the Company considers the likelihood of contingent consideration payment to be low, resulting in no value being ascribed to the contingent consideration in the purchase price allocation.

Buckthorn Wind is located in Erath County, approximately 60 miles south of Dallas, Texas and began commercial operations in January 2018. It operates in the liquid Electric Reliability Council of Texas (ERCOT) North region between most of the wind generation in ERCOT-West and the Dallas load center. The ERCOT North region has strong fundamentals with a high likelihood of baseload generation retirements and is one of the fastest growing regions in the United States.

Buckthorn Wind has a 15-year weighted average contract life remaining with two offtake arrangements including one with JPMorgan Chase Bank involving a 20-year contract for differences (CfD) for 55% of the generation output, and a 13-year financial hedge for the remaining 45% of the output. The long-term contracts strengthen the Company's contracted cash flow profile while expanding our renewables portfolio.

Buckthorn Wind has a tax equity investor (TEI) where the TEI receives the majority of the cash flows prior to the date on which the TEI reaches the agreed upon target rate of return (the flip date). The flip date is expected to occur in the late 2020s. Prior to the flip date, the Company expects average annual adjusted EBITDA and AFFO to be approximately $18 million (US$14 million) and $1 million (US$1 million), respectively. After the flip date during the CfD, the average annual adjusted EBITDA and AFFO are expected to be approximately $9 million (US$8 million) and $6 million (US$5 million), respectively.

Cardinal Point Wind begins commercial operations

On March 16, 2020, Cardinal Point Wind, a 150 MW facility in the McDonough and Warren Counties, Illinois, began commercial operations. Subsequently, the Company received approximately $221 million (US$157 million) in tax equity financing on March 26, 2020, net of issue costs of $3 million (US$2 million) associated with the financing, from two U.S. financial institutions in exchange for Class A interests of a subsidiary of the Company. The construction of the facility was completed on-schedule and as final costs are incurred during the remainder of 2020, is expected to be within its projected total cost of US$236 million to US$246 million (see Liquidity and Capital Resources).

Capital Power will operate Cardinal Point Wind under a 12-year fixed price contract with an investment grade U.S. financial institution covering 85% of the facility's output. The expected adjusted EBITDA and AFFO in the first full year of operations are $56 million (US$40 million) and $6 million (US$4 million), respectively.

Discontinuation of the Genesee 4 and 5 project

During the first quarter of 2020, the Company and its partner on the Genesee 4 and 5 project determined that they would no longer be pursuing the project. Arbitration has commenced between the Company and its partner around the costs of exiting the series of agreements previously entered into. As a result of the decision to no longer pursue the project, the Company has determined that $13 million of capital expenditures incurred by the Company were purely related to the development of Genesee 4 and 5. The Company has therefore recorded a write-off of these capital costs during the first quarter of 2020 within depreciation and amortization.

SUBSEQUENT EVENTS

20-year contracts for three new solar development projects in North Carolina

In October 2020, the Company executed 20-year power purchase agreements with Duke Energy Carolinas for three solar development projects located in North Carolina totaling 160 MW. The solar projects consist of Hornet Solar (75 MW), Hunter's Cove Solar (50 MW), and Bear Branch Solar (35 MW) (collectively, the "solar projects"). Construction of the solar projects is expected to begin in late 2021 or early 2022 with commercial operations expected in the fourth quarter of 2022 and with expected capital costs of $118 million (US$90 million), $82 million (US$62 million) and $60 million (US$46 million) for the three projects, respectively. Capital Power expects to finance the solar projects using debt and tax equity.

With their 20-year contract terms, the North Carolina solar projects will strengthen our contracted cash flows while increasing the average remaining contract life of our contracted assets. The investment is expected to meet Capital Power's after-tax hurdle rate with the average accretion expected to be neutral to AFFO in the first five years. The solar projects are expected to generate approximately $23 million (US$17 million) of adjusted EBITDA and $5 million (US$4 million) of AFFO annually on average in the first five years.

$350 million medium-term note offering and early redemption of $251 million medium-term notes

On October 1, 2020 the Company closed a public offering of unsecured medium-term notes in the aggregate principal amount of $350 million (the Offering). The notes have a coupon rate of 3.147% and mature on October 1, 2032. The net proceeds of the Offering have been and will be used to repay, redeem or refinance existing indebtedness, including indebtedness under outstanding debt securities or credit facilities, or for general corporate purposes. Included in such repayments is the redemption, on October 9, 2020, of all of the Company's outstanding 5.276% medium-term notes, due November 16, 2020, in the aggregate principal amount of $251 million. The redemption price was an aggregate amount of $258 million, including applicable early redemption premiums, as well as accrued and unpaid interest to and including the day immediately preceding the redemption date.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for the three and nine months ended September 30, 2020 compared with the three and nine months ended September 30, 2019 are presented below followed by further discussion of these items.

(unaudited, $ millions)	Three months		Nine months	
Consolidated net loss for the periods ended September 30, 2019		**(228)**		**(62)**
Increase (decrease) in adjusted EBITDA:				
Alberta commercial facilities and portfolio optimization	8		(6)	
Alberta contracted facilities	7		34	
Ontario and British Columbia contracted facilities	6		64	
U.S. contracted facilities	(19)		(24)	
Corporate	(2)	-	(10)	58
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		23		(86)
Decrease in impairments		401		401
Decrease (increase) in depreciation and amortization expense		20		(14)
Decrease (increase) in foreign exchange loss		2		-
Decrease (increase) in finance expense and depreciation expense from joint ventures		3		(1)
Increase in net finance expense		(5)		(25)
Increase in income before tax		444		333
Change in income tax expense or recovery		(110)		(142)
Increase in net income		**334**		**191**
Consolidated net income for the periods ended September 30, 2020		**106**		**129**

Results by facility category and other

	Three months ended September 30							
	2020	2019	2020	2019	2020	2019	2020	2019
	Electricity generation (GWh) [1]		**Facility availability** (%) [2]		**Revenues and other income** (unaudited, $ millions)		**Adjusted EBITDA** (unaudited, $ millions) [3]	
Total electricity generation, average facility availability and facility revenues	6,327	6,808	98	96	407	416		
Alberta commercial facilities [4]								
Genesee 3 [5]	1,014	492	100	96	44	22		
Keephills 3 [5]	N/A	450	N/A	93	N/A	19		
Clover Bar Energy Centre 1, 2 and 3	98	348	98	96	10	18		
Joffre	171	150	99	82	13	10		
Shepard Energy Centre	784	782	100	100	33	34		
Halkirk	117	86	96	95	9	8		
Clover Bar Landfill Gas	1	-	37	-	-	-		
Alberta commercial facilities	2,185	2,308	99	95	109	111		
Portfolio optimization	N/A	N/A	N/A	N/A	99	70		
	2,185	2,308	99	95	208	181	80	72
Alberta contracted facilities [4]								
Genesee 1	739	803	100	96	35	32		
Genesee 2	696	795	100	100	31	36		
Whitla Wind 1 [6]	170	N/A	98	N/A	7	N/A		
	1,605	1,598	99	98	73	68	56	49
Ontario and British Columbia contracted facilities								
Island Generation	47	379	100	99	10	10		
York Energy [7]	4	3	98	99	N/A	N/A		
East Windsor	2	2	99	99	8	8		
Goreway [8]	329	304	93	87	52	53		
Kingsbridge 1	15	15	98	98	2	1		
Port Dover and Nanticoke	53	46	93	94	8	7		
Quality Wind	108	73	98	96	12	9		
EnPower	2	3	100	72	-	-		
	560	825	96	92	92	88	69	63
U.S. contracted facilities								
Roxboro, North Carolina	84	88	99	99	10	10		
Southport, North Carolina	100	112	98	84	16	17		
Decatur Energy, Alabama	665	709	100	100	36	36		
Arlington Valley, Arizona	693	878	99	100	36	61		
Beaufort Solar, North Carolina	8	8	99	100	1	1		
Bloom Wind, Kansas	154	176	95	98	10	13		
Macho Springs, New Mexico	21	21	97	97	2	2		
New Frontier Wind, North Dakota	95	85	97	97	8	9		
Cardinal Point Wind, Illinois [9]	86	N/A	92	N/A	9	N/A		
Buckthorn Wind, Texas [10]	71	N/A	94	N/A	5	N/A		
	1,977	2,077	98	99	133	149	96	115
Corporate [11]					13	15	(17)	(15)
Unrealized changes in fair value of commodity derivatives and emission credits					(66)	16		
Consolidated revenues and other income and adjusted EBITDA					**453**	**517**	**284**	**284**

	Nine months ended September 30							
	2020	2019	2020	2019	2020	2019	2020	2019
	Electricity generation (GWh) [1]		**Facility availability** (%) [2]		**Revenues and other income** (unaudited, $ millions)		**Adjusted EBITDA** (unaudited, $ millions) [3]	
Total electricity generation, average facility availability and facility revenues	17,361	18,090	94	95	1,203	1,133		
Alberta commercial facilities [4]								
Genesee 3 [5]	2,853	1,494	96	99	135	85		
Keephills 3 [5]	N/A	1,353	N/A	95	N/A	72		
Clover Bar Energy Centre 1, 2 and 3	373	908	95	95	35	60		
Joffre	489	587	97	94	42	49		
Shepard Energy Centre	2,421	2,268	100	94	105	110		
Halkirk	386	313	98	97	33	32		
Clover Bar Landfill Gas	3	-	46	-	-	-		
Alberta commercial facilities	6,525	6,923	97	95	350	408		
Portfolio optimization	N/A	N/A	N/A	N/A	245	103		
	6,525	6,923	97	95	595	511	221	227
Alberta contracted facilities [4]								
Genesee 1	2,220	2,196	99	89	103	83		
Genesee 2	2,087	2,341	98	98	93	105		
Whitla Wind 1 [6]	600	N/A	97	N/A	26	N/A		
	4,907	4,537	98	94	222	188	168	134
Ontario and British Columbia contracted facilities								
Island Generation	54	713	100	100	29	29		
York Energy [7]	11	11	99	100	N/A	N/A		
East Windsor	5	7	98	99	24	26		
Goreway [8]	689	380	92	90	152	69		
Kingsbridge 1	68	71	98	98	6	6		
Port Dover and Nanticoke	213	210	97	97	31	31		
Quality Wind	329	224	97	97	37	29		
EnPower	15	13	87	75	1	1		
	1,384	1,629	95	96	280	191	219	155
U.S. contracted facilities								
Roxboro, North Carolina	249	238	96	96	30	28		
Southport, North Carolina	319	332	94	88	50	49		
Decatur Energy, Alabama	1,116	1,489	87	93	72	74		
Arlington Valley, Arizona	1,474	2,022	81	94	90	116		
Beaufort Solar, North Carolina	22	23	100	100	2	2		
Bloom Wind, Kansas	549	520	97	99	33	36		
Macho Springs, New Mexico	99	103	98	98	11	12		
New Frontier Wind, North Dakota	307	274	98	96	25	29		
Cardinal Point Wind, Illinois [9]	242	N/A	93	N/A	26	N/A		
Buckthorn Wind, Texas [10]	168	N/A	94	N/A	12	N/A		
	4,545	5,001	88	94	351	346	183	207
Corporate [11]					36	47	(56)	(46)
Unrealized changes in fair value of commodity derivatives and emission credits					(63)	(3)		
Consolidated revenues and other income and adjusted EBITDA					**1,421**	**1,280**	**735**	**677**

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 cash-generating unit (CGU) for impairment testing purposes. Since the cash flows of Genesee 1 and 2 will remain contracted through 2020, management will continue to present the Genesee 1 and 2 results within the Alberta Contracted grouping through 2020.

5 On October 1, 2019, the Company divested its 50% share of Keephills 3 and, in exchange, acquired TransAlta Corporation's 50% share of Genesee 3.

6 Phase 1 of Whitla Wind was commissioned on December 1, 2019.

7 York Energy is accounted for under the equity method. Capital Power's share of the facility's net income is included in loss 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 $23 million for three and nine months ended September 30, 2020, respectively, compared with $7 million and $23 million for the three and nine months ended September 30, 2019, respectively. The facility's revenues are not included in the above results.

8 Goreway was acquired on June 4, 2019.

9 Cardinal Point Wind was commissioned on March 16, 2020 (see Significant Events).

10 Buckthorn Wind was acquired on April 1, 2020 (see Significant Events).

11 Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

		Three months ended Sep 30		Nine months ended Sep 30		Year ended
Alberta	**Unit**	**2020**	**2019**	**2020**	**2019**	**December 31, 2019**
Hedged position [1]	Percentage sold forward at beginning of period (%)	100	100	73	80	78
Spot power price average	$ per megawatt hour (MWh)	44	47	47	58	55
Realized power price [2]	$ per MWh	59	59	58	58	57
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	2.17	0.99	2.03	1.73	1.87

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 $44 per MWh and $47 per MWh for the three and nine months ended September 30, 2020, respectively which were lower than the corresponding periods in 2019. Lower spot pricing in 2020 reflected lower market demand as a result of both reduced oil and gas production and the COVID-19 pandemic. In addition, moderate temperatures, stable baseload supply and strong hydro and wind generation all resulted in reduced pricing.

Availability for the three and nine months ended September 30, 2020 was higher than the corresponding periods in 2019 primarily due to no planned outage and fewer unplanned outages at Shepard Energy Centre in 2020, no planned outage at Joffre in the third quarter of 2020 and no unplanned outages at Genesee 3 in the third quarter of 2020, compared with outages in the third quarter of 2019 for these facilities. These favourable variances were partially offset by more frequent unplanned outages at Genesee 3 in the first half of 2020 and planned and unplanned outages at Joffre in the first three months of 2020.

Despite higher availability in the three and nine months ended September 30, 2020 compared with the corresponding periods in 2019, generation was lower in 2020 compared with 2019. Lower generation for the three months ended September 30, 2020 was primarily due to lower dispatch at Clover Bar Energy Centre, partially offset by higher wind resource availability at Halkirk and higher facility availability at Genesee 3. Lower generation for the nine months ended September 30, 2020 was primarily due to lower dispatch at Clover Bar Energy Centre and Joffre, partially offset by fewer outage days at Shepard as described above and higher wind resource availability at Halkirk. Lower generation in the nine months ended September 30, 2020 was also driven by more frequent unplanned outages at Genesee 3 compared with the same period in 2019.

Revenues and other income for the three and nine months ended September 30, 2020 were higher than the comparable periods in 2019, driven by higher revenues from portfolio optimization activities, partially offset by lower revenues from Alberta commercial facilities due to lower generation and lower spot power prices in 2020. Higher revenues from portfolio optimization activities included higher sales of natural gas as well as a larger excess of realized power prices over spot power prices in 2020 as compared to 2019.

Adjusted EBITDA for the three months ended September 30, 2020 was higher than 2019, primarily due to higher margins earned on power and natural gas portfolio optimization activities and lower maintenance costs driven by higher availability, partially offset by the impact of lower generation. Adjusted EBITDA for the nine months ended September 30, 2020 was lower than 2019, primarily due to the impact of lower generation and lower margins earned on the trading of emission credits, partially offset by higher margins earned on power and natural gas portfolio optimization activities and lower energy purchases and fuel costs in the nine months ended September 30, 2020 compared to the same period in 2019 due to the swap of interests in Genesee 3 and Keephills 3 during the fourth quarter of 2019. Realized power prices for the three and nine months ended September 30, 2020 were consistent with the corresponding periods in 2019.

Alberta contracted facilities

Generation, availability, revenues and other income and adjusted EBITDA for the three months ended September 30, 2020 were higher compared with the corresponding period in 2019 primarily due to the commencement of commercial operations at Whitla Wind 1 in the fourth quarter of 2019 and no outages in the third quarter of 2020 at Genesee 1 or 2 compared with a forced outage at Genesee 1 in the corresponding period in 2019.

Generation, availability, revenues and other income and adjusted EBITDA for the nine months ended September 30, 2020 were higher compared with the corresponding period in 2019 due to the noted variances for the quarterly period and no planned outage at Genesee 1 and 2 in 2020, compared with a planned outage at Genesee 1 in the second quarter of 2019. Despite no planned outages at Genesee 1 and 2 in 2020, generation for Genesee 1 and 2 was lower in the three and nine months ended September 30, 2020 compared with the corresponding periods in 2019 primarily due to lower dispatch by the power purchase arrangement buyer.

Ontario and British Columbia contracted facilities

Generation for the three and nine months ended September 30, 2020 was lower compared with the corresponding periods in 2019 primarily due to lower dispatch at Island Generation, partially offset by higher wind resource availability at Quality Wind and the acquisition of Goreway in the second quarter of 2019. Availability for the three months ended September 30, 2020 was higher primarily due to the timing of the planned outage at Goreway which, although similar in duration to the planned outage in 2019, was completed early in the fourth quarter of 2020. Availability for the nine months ended September 30, 2020 was driven by the timing of the Goreway outage noted above, slightly offset by planned outages at Goreway and East Windsor in the second quarter of 2020 compared with no planned outages in the corresponding quarter of 2019 and multiple unplanned outages at Goreway in the first quarter of 2020.

Revenues and other income and adjusted EBITDA were higher in the three months ended September 30, 2020 compared with the corresponding period in 2019 most notably due to higher generation at Quality Wind and the timing of the planned outage at Goreway in 2020 noted above. Further adding to the favourable variances on a year-to-date basis was the acquisition of Goreway in the second quarter of 2019, partially offset by lower revenues and adjusted EBITDA at East Windsor as a result of lower system support revenue in 2020. Revenues and other income do not include York Energy, which is accounted for under the equity method.

U.S. contracted facilities

Generation and availability decreased in the three and nine months ended September 30, 2020 compared with the corresponding periods in 2019 primarily due to lower dispatch at Decatur Energy and Arlington Valley and higher planned outage hours at Decatur Energy and Arlington Valley in 2020. The unfavourable availability variances were partially offset by fewer unplanned outages and shorter planned outages at Southport compared to the first three and nine months of 2019. The unfavourable generation variances were partially offset by the commencement of commercial operations at Cardinal Point Wind (see Significant Events) in March 2020 and the acquisition of Buckthorn Wind in April 2020 (see Significant Events).

Revenues and other income for the three months ended September 30, 2020 were lower than the corresponding period in 2019 largely due to lower revenue at Arlington Valley due to a revised tolling agreement in 2020 and lower tax attributes recognized by Bloom Wind and New Frontier Wind in 2020 compared with 2019. These unfavourable variances were partially offset by the commencement of commercial operations of Cardinal Point Wind and the acquisition of Buckthorn Wind during 2020.

Revenues and other income for the nine months ended September 30, 2020 were higher than the corresponding period in 2019, largely due to the same factors described for the three-month period above with the increases exceeding the decreases.

Adjusted EBITDA for the three and nine months ended September 30, 2020 was lower compared with the corresponding periods in 2019 primarily attributable to the noted impacts for revenues and other income. For the nine months ended September 30, 2020, higher outage costs at Decatur Energy and Arlington Valley also contributed to lower adjusted EBITDA as compared to the comparable period of 2019.

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.

Net corporate revenues and other income were lower in the three and nine months ended September 30, 2020 compared with the corresponding periods in 2019 mainly due to reduced recognition of coal compensation revenue as a result of the swap of interests in Genesee 3 and Keephills 3 during the fourth quarter of 2019. Net corporate expenditures for the three and nine months ended September 30, 2020 were higher than the comparable periods in 2019 primarily due to the noted coal compensation revenue impact, an increase in the provision for the Line Loss Rule proceeding (see Contingent Liabilities and Provisions) in the second quarter of 2020, restructuring charges incurred in the third quarter of 2020 and costs related to the acquisition of Buckthorn Wind in the second quarter of 2020, partially offset by lower incentive expenses due to a decrease in the Company's share price during 2020.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Three months ended September 30			
	2020	**2019**	**2020**	**2019**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Income before tax**	
Unrealized (losses) gains on Alberta power derivatives	(6)	22	(2)	(4)
Unrealized losses on U.S. power derivatives	(24)	(6)	(24)	(6)
Unrealized (losses) gains on natural gas derivatives	(31)	(3)	63	11
Unrealized (losses) gains on emission derivatives	(5)	3	(5)	3
Unrealized (losses) gains on emission credits held for trading	-	-	(1)	4
	(66)	**16**	**31**	**8**

(unaudited, $ millions)	Nine months ended September 30			
	2020	**2019**	**2020**	**2019**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Income before tax**	
Unrealized gains (losses) on Alberta power derivatives	25	(38)	(13)	27
Unrealized (losses) gains on U.S. power derivatives	(42)	35	(42)	35
Unrealized (losses) gains on natural gas derivatives	(34)	(2)	76	28
Unrealized (losses) gains on emission derivatives	(12)	2	(12)	2
Unrealized losses on emission credits held for trading	-	-	(5)	(2)
	(63)	**(3)**	**4**	**90**

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 and nine months ended September 30, 2020 unrealized losses of $2 million and $13 million, respectively, were recognized on Alberta power derivatives, primarily due to the reversal of prior period unrealized gains on positions that settled during the period. During the three months ended September 30, 2019, the Company recognized unrealized losses of $4 million as a result of the reversal of prior period unrealized net gains on forward sale contracts that settled during the period. During the nine months ended September 30, 2020 unrealized gains of $27 million were recognized on Alberta power derivatives, largely due to the impact of increasing forward Alberta power prices on net forward purchase contracts.

During the three and nine months ended September 30, 2020 the U.S. power portfolio recognized unrealized losses of $24 million and $42 million, respectively, due to the impact of increasing forward prices on forward sale contracts. During the three months ended September 30, 2019, the Company recognized unrealized losses of $6 million due to the impact of increasing forward prices on forward sale contracts. During the nine months ended September 30, 2019, the U.S. power portfolio recognized unrealized gains of $35 million due to the impact of decreasing forward prices on forward sale contracts.

During the three and nine months ended September 30, 2020 the Company recognized unrealized gains on natural gas derivatives of $63 million and $76 million, respectively, due to the impact of increasing forward prices on forward purchase contracts. During the three and nine months ended September 30, 2019, the Company recognized unrealized gains on natural gas derivatives of $11 million and $28 million, respectively, as a result of net forward purchase contracts valued against increasing forward natural gas prices, and the reversal of prior periods' unrealized losses on positions that settled during the period.

During the three months ended September 30, 2020 the Company recognized unrealized losses of $5 million on emission derivatives as a result of the reversal of prior period unrealized gains on positions that settled during the quarter. During the nine months ended September 30, 2020, the Company recognized unrealized losses of $12 million due mainly to decreasing forward prices on forward purchase contracts as well as the reversal of prior period unrealized gains on positions that settled during the year. During the comparable periods in 2019, unrealized gains of $3 million and $2 million were recognized due to the impact of increasing forward prices on net forward purchase contracts as well as the reversal of prior period unrealized losses on positions that settled in 2019.

During the nine months ended September 30, 2020, the Company recorded unrealized losses of $5 million on emission credits held for trading primarily due to the reversal of prior period gains on emission credits sold during the period. During the three months ended September 30, 2019, the Company recorded unrealized gains of $4 million on emission credits held for trading, due to the impact of increasing market prices on portfolio holdings. During the nine months ended September 30, 2019 the Company recorded unrealized losses of $2 million on emission credits held for trading, primarily due to the reversal of prior period unrealized net gains on emission credits sold during those periods.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Interest on borrowings less capitalized interest	(40)	(35)	(121)	(97)
Realized losses on settlement of interest rate derivatives	(2)	(1)	(3)	(2)
Other net finance expense – interest on coal compensation from the Province of Alberta, sundry interest, guarantee and other fees	-	1	3	3
	(42)	(35)	(121)	(96)
Unrealized losses representing changes in the fair value of interest rate derivatives	-	-	(2)	-
Other net finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta	(5)	(7)	(17)	(19)
Total net finance expense	(47)	(42)	(140)	(115)
Impairment	-	(401)	-	(401)
Depreciation and amortization	(115)	(135)	(369)	(355)
Foreign exchange gain (loss)	1	(1)	(5)	(5)
Finance expense and depreciation expense from joint ventures	(4)	(7)	(23)	(22)
Income tax (expense) recovery	(44)	66	(73)	69
Net loss attributable to non-controlling interests	2	2	4	5

Net finance expense

Higher net finance expense for the three months ended September 30, 2020, is mainly due to financing related to the acquisition of Buckthorn Wind (see Significant Events) in the second quarter of 2020 and interest on tax equity financing related to Cardinal Point Wind (see Significant Events) that commenced commercial operations in the first quarter of 2020. Further adding to the higher finance expense for 2020 was higher long-term debt interest related to the acquisition of Goreway in the second quarter of 2019 and lower capitalized interest due to construction of Cardinal Point Wind and Whitla Wind 1 in 2019.

Impairment

During the three and nine months ended September 30, 2019, the Company recognized a pre-tax impairment of $401 million related to the classification of Keephills 3 as an asset held for sale prior to its divestiture in the fourth quarter of 2019.

Depreciation and amortization

Depreciation and amortization for the three months ended September 30, 2020 decreased compared with the same period in the prior year due largely to lower amortization at Arlington Valley on the facility's tolling agreements that were acquired with the facility, as the tolling agreement in effect in 2019 had significantly higher amortization than the tolling agreement in effect for 2020. Also contributing to lower depreciation was the reduction in depreciable assets resulting from the Genesee 3 and Keephills 3 swap transaction in 2019 driving lower depreciation in 2020 as well as lower depreciation of shutdown capital at Genesee as a result of the 2020 outage being deferred to 2021. These impacts were mostly offset by higher depreciation resulting from Cardinal Point Wind and Whitla Wind 1 commencing commercial operations in March 2020 and the last quarter of 2019, respectively, and the addition of Buckthorn Wind in the second quarter of 2020 (see Significant Events).

Depreciation and amortization for the nine months ended September 30, 2020 was also impacted by the factors noted above, as well as an increase from the acquisition of Goreway in the second quarter of 2019. Additionally contributing to the overall increase in depreciation and amortization are the losses on the discontinuation of the Genesee 4 and 5 project (see Significant Events) and the loss recognized on the termination of the East Windsor steam contract in the second quarter of 2020 included in depreciation and amortization on the condensed interim consolidated statements of income.

Foreign exchange gain (loss)

As at September 30, 2020, the Company had outstanding foreign currency non-hedge sale contracts totalling US$52 million. For the three months ended September 30, 2020, the exchange rate of the Canadian dollar relative to the U.S. dollar strengthened resulting in an unrealized gain on the foreign currency sale contracts, partially offset by realized losses on the settlement of foreign currency sale contracts in the quarter. For the nine months ended September 30, 2020, the unrealized loss is mostly attributable to outstanding foreign currency non-hedge sale contracts in the first quarter of 2020, during which the Canadian dollar weakened against the U.S. dollar.

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

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, which is accounted for under the equity method. Finance expense and depreciation expense from joint ventures decreased for the three months ended September 30, 2020 compared with the same period in 2019 due to lower losses during the third quarter of 2020 on the interest rate non-hedge held within the York Energy joint venture.

Income tax expense

For the three and nine months ended September 30, 2020 income tax expense was $44 million and $73 million, respectively, compared to income tax recovery of $66 million and $69 million in the corresponding periods of 2019. The increase in income tax expense was due to the impairment of Keephills 3 recognized in the third quarter of 2019 which resulted in the recognition of a deferred income tax recovery, of which there is no comparable tax recovery recognized in the current quarter. Also, the decrease in the Alberta corporate income tax rate initiated on June 28, 2019 resulted in the recognition of a deferred income tax recovery of $51 million in the nine months ended September 30, 2019, of which there is no comparable tax recovery recognized in the current 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 (LOSS)

(unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2020	**2019**	**2020**	**2019**
Net income (loss)	106	(228)	129	(62)
Other comprehensive (loss) income:				
Actuarial gain related to the Company's defined benefit pension plan	-	-	3	-
Net unrealized gains (losses) on derivative instruments designated as cash flow hedges	3	19	(5)	(53)
Net realized (gains) losses on derivative instruments designated as cash flow hedges reclassified to net income	(11)	(6)	(20)	14
Unrealized foreign exchange (losses) gains on the translation of foreign operations	(18)	11	29	(22)
Total other comprehensive (loss) income, net of tax	(26)	24	7	(61)
Comprehensive income (loss)	**80**	**(204)**	**136**	**(123)**

Other comprehensive (loss) 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 (loss) 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, 2019 to September 30, 2020 were as follows:

(unaudited, $ millions)	As at September 30, 2020	As at December 31, 2019	Increase (decrease)	Acquisitions through business combinations	Other	Primary other changes
Trade and other receivables	483	334	149	1	148	Increase primarily due to gross Line Loss Rule Proceeding (LLR) invoice accrual (see Contingent Liabilities and Provisions) and the timing of collection of generation receivables.
Right-of-use assets	130	95	35	7	28	Increase primarily due to the recording of land leases on commencement of commercial operations at Cardinal Point Wind (see Significant Events) less depreciation.
Property, plant and equipment	6,255	6,089	166	178	(12)	Decrease due to depreciation partly offset by capital additions, including Cardinal Point Wind and Whitla Wind 2, and foreign exchange impacts.
Net derivative financial instruments liabilities	4	64	(60)	(48)	(12)	Impact of decreasing forward interest rates on existing interest rate swaps and decreasing forward prices on foreign exchange swaps transacted during the first nine months of 2020, partly offset by the impact of decreasing forward power prices on forward sale contracts and increasing forward natural gas prices on forward purchase contracts.
Trade and other payables	434	301	133	2	131	Increase primarily due to gross LLR invoice accrual (see Contingent Liabilities and Provisions) and settlement timing of emissions liabilities, partly offset by decrease to income taxes payable due to tax payable on the gain on disposal of K2 Wind in 2019 paid in 2020.
Loans and borrowings (including current portion)	3,422	3,413	9	103	(94)	Decrease due to net repayment of credit facilities and non-cash repayments of tax equity financing, partly offset by Cardinal Point Wind tax equity funding received during the first quarter (see Significant Events).

(unaudited, $ millions)	As at September 30, 2020	As at December 31, 2019	Increase (decrease)	Acquisitions through business combinations	Other	Primary other changes
Provisions (including current portion)	501	457	44	6	38	Increase mainly due to additional decommissioning liabilities incurred for development projects and revisions to existing decommissioning provisions driven by reductions in interest rates, partly offset by the payment of accrued employee benefits and the removal of LLR provisions (see Contingent Liabilities and Provisions) that are now reflected gross as accrued receivables and accrued payables.
Lease liabilities (including current portion)	148	111	37	7	30	Increase primarily due to the recording of land leases on commencement of commercial operations at Cardinal Point Wind (see Significant Events) partially offset by lease payments.
Net deferred tax liabilities	580	488	92	34	58	Increase primarily due to the utilization of losses generated, recognition of taxable temporary differences that will reverse in the future and changes in derivative financial instrument balances.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Nine months ended September 30		
Cash inflows (outflows)	**2020**	**2019**	**Change**
Operating activities	452	519	(67)
Investing activities	(283)	(738)	455
Financing activities	(286)	175	(461)

Operating activities

Cash flows from operating activities for the nine months ended September 30, 2020 decreased compared with the same period in 2019 due to various increases in cash outflows in 2020 including (i) an increase in income taxes paid, (ii) higher interest paid due to additional loans and borrowings, and (iii) cash outflows for 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 compared to inflows in 2019. These impacts were partially offset by an increase in cash inflows resulting from facility operations as described in Consolidated Net Income and Results of Operations for adjusted EBITDA. The most notable factors include the acquisitions of Goreway in June 2019 and Buckthorn Wind (see Significant Events) in April 2020, Cardinal Point Wind beginning commercial operations in March 2020, the commissioning of Whitla Wind 1 in the fourth quarter of 2019 and reduced outage hours at Genesee 1 and 2 including the noted deferral of the Genesee 2 planned outage to 2021, partially offset by lower realized gains on the trading of emission credits and reduced tolling revenues from Arlington Valley due to the revised tolling agreement in effect in 2020.

Investing activities

Cash flows used in investing activities for the nine months ended September 30, 2020 decreased compared with the same period in 2019 primarily due to the acquisition of Goreway in the second quarter of 2019 and lower capital expenditures during 2020 as Whitla Wind 1 was commissioned in the fourth quarter of 2019 and Cardinal Point Wind in March 2020. These impacts were partially offset by the acquisition of Buckthorn Wind (see Significant Events) in the second quarter of 2020 and by cash inflows from the collection of outstanding receivables from the disposal of K2 Wind in the first quarter of 2019.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2020 actual	Nine months ended September 30, 2020 actual	Balance of 2020 estimated [1, 2]	Actual or projected total [2]	Timing
Genesee 4 and 5 [3]	18	-	-	-	Project discontinued (see Significant Events)
Whitla Wind 1 [4]	322	12	-	334	Completed in December 2019
Cardinal Point Wind [5]	256	55	4	315	Completed in March 2020
Whitla Wind 2 and 3	-	24	5	257	Targeted completion in the fourth quarter of 2021
Strathmore Solar	-	2	6	53	Targeted completion in the first half of 2022
Commercial initiatives [6]	81	61	14	235	
Development sites and projects	20	4	-		
Subtotal growth projects		**158**	**29**		
Sustaining – facility maintenance excluding Genesee mine		48			
Sustaining – Genesee mine maintenance and lands		6			
Total capital expenditures [7]		**212**			
Emission credits held for compliance		24			
Investment in C2CNT		4			
Capitalized interest		(4)			
Purchase of property, plant and equipment and other assets		**236**			

1 The Company's 2020 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 Whitla Wind 1, 2 and 3, Cardinal Point Wind, Strathmore Solar and commercial initiatives 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 stage.

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

4 The original projected total construction cost for Whitla Wind 1 was expected to be in the range of $315 million to $325 million. Actual project costs exceeded that range driven by foreign exchange impacts on U.S. dollar costs. These amounts were partially economically hedged by forward U.S. currency purchase derivatives which settled in the year ended December 31, 2019 resulting in realized foreign exchange gains of $8 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 1 into the initial Alberta Renewable Electricity Program and the date that Whitla Wind 1 was awarded the contract, which were not hedged. Whitla Wind 1 began commercial operations in December 2019. The finalization of construction activities occurred during the first quarter of 2020.

5 The projected total cost for Cardinal Point Wind of US$237 million is near the low end of the expected range of construction costs in the facility's U.S. dollar functional currency of US$236 million to US$246 million. In Canadian dollars, the projected total cost exceeds the expected range of construction costs of $289 million to $301 million driven by foreign exchange rate impacts.

6 Commercial initiatives include the combustion turbine upgrade projects for Decatur Energy with capital expenditures incurred to the end of September 30, 2020 of $61 million (US$46 million). These projects resulted in an additional 60 MW of generation to date. Commercial initiatives also include expected spending on the Company's Genesee dual-fuel project and the Genesee Performance Standard project as well as various other projects designed to either increase the capacity or efficiency of their respective facilities or to reduce emissions.

7 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 used in financing activities for the nine months ended September 30, 2020 reflected the issuance of approximately $221 million (US$157 million) in net tax equity financing related to Cardinal Point Wind, offset by net repayment of loans and borrowings, payment of common and preferred share dividends and repurchase of common shares under the Company's normal course issuer bid.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at September 30, 2020			As at December 31, 2019		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
Committed credit facilities	2024	1,000			1,000		
Letters of credit outstanding			10			50	
Bankers' acceptances outstanding			-			-	
Bank loans outstanding [1]			86			319	
		1,000	96	904	1,000	369	631
Bilateral demand credit facilities	N/A	433			430		
Letters of credit outstanding			221			189	
		433	221	212	430	189	241
Demand credit facilities	N/A	25	-	25	25	-	25
		1,458	**317**	**1,141**	**1,455**	**558**	**897**

1 U.S. dollar denominated bank loans outstanding totaling US$65 million (December 31, 2019 – US$246 million).

As at September 30, 2020, the committed credit facility utilization decreased $273 million compared with the utilization as at December 31, 2019, due to decreased letters of credit and U.S. dollar bank loans outstanding most notably driven by the receipt of tax equity financing on Cardinal Point Wind during 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) which was affirmed in their latest report, published July 13, 2020. 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) which was affirmed in their latest report, published April 7, 2020. 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 2020 include:

(unaudited, $ millions)	**Nine months ended September 30, 2020 actual**	**Balance of 2020 estimated**	**Total 2020 expected cash requirements**
Net repayment of debt payable [1]	46	266	312
Capital expenditures – sustaining	50	30	80
Capital expenditures – ongoing growth projects	97	15	112
Capital expenditures – commercial initiatives	61	14	75
Common share dividends [2]	151	38	189
Preferred share dividends	39	13	52
	444	**376**	**820**

1 Excludes repayment of credit facilities.

2 Includes 6.8% annual dividend growth (see Significant Events).

The Company uses a short-form base shelf prospectus to provide it with the ability, market conditions permitting, to obtain new debt and equity capital from external markets when required. Under the short-form base shelf prospectus, Capital Power may raise up to $3 billion by issuing common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities. This prospectus expires in June 2022.

If the Canadian and U.S. financial markets become unstable as they have during 2020, 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 power purchase agreement or arrangement (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. See Risks and Risk Management for additional discussion on recent developments pertaining to these risks and Capital Power's risk mitigation strategies.

Off-statement of financial position arrangements

As at September 30, 2020, the Company has $231 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements and to satisfy legislated reclamation requirements. If the Company were to terminate these off-statement of financial position arrangements, the penalties or obligations would not have a material impact on the Company's financial condition, results of operations, liquidity, capital expenditures or resources.

Capital resources

(unaudited, $ millions)	As at	
	September 30, 2020	**December 31, 2019**
Loans and borrowings	3,422	3,413
Lease liabilities [1]	148	111
Less cash and cash equivalents	(130)	(248)
Net debt	3,440	3,276
Share capital	3,438	3,441
Deficit and other reserves	(433)	(377)
Non-controlling interests	31	37
Total equity	3,036	3,101
Total capital	**6,476**	**6,377**

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 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 resulting adjustment of line loss charges and credits for the years 2006 up to and including 2016.

The Company is participating in legal or regulatory processes rendering details of the final outcome of the LLR Proceeding still unknown. However, based on current AUC decisions, Capital Power would incur additional charges related to historical periods and, as such, has recorded $18 million pertaining to the estimated net liability for its currently held Alberta assets. This amount reflects an increase of $3 million recorded during the second quarter of 2020 to reflect updated information published by the Alberta Electric System Operator (AESO). The invoicing process will result in gross billings to Capital Power of which those amounts not attributable to Capital Power will then be recoverable from the appropriate parties. To reflect the invoicing process, beginning with the period ended June 30, 2020 and as at September 30, 2020, the Company recorded gross amounts of $118 million in trade and other receivables and $136 million in trade and other payables as compared to the net amount recorded as a provision in prior periods. These amounts have been estimated by the Company based on information published by the AESO to date but are subject to change as additional information is published or as invoices are received.

Timing of invoicing for the LLR adjustments has also been accelerated. The AUC rendered a decision on July 9, 2020 directing the AESO to issue three separate invoices for the various historic years instead of a single invoice for the entire period. The AESO's invoicing compliance plan was subsequently approved in September 2020. As a result, the

AESO issued the first invoice covering the years 2014-2016 in October 2020 and payment for the related amounts is to occur by the end of 2020. Subsequently, the amounts payable but not attributable to the Company have been invoiced to the appropriate parties for recovery. The second invoice covering the years 2010-2013 and third invoice covering the years 2006 – 2009 are expected to be issued by the end of 2020 and first quarter of 2021, respectively, with Capital Power in turn invoicing the appropriate parties for their respective shares along similar timelines. Payment of the second and third invoices is estimated by the AESO to occur over the course of the first half of 2021. The AESO timing estimates remain subject to change as it works through the invoicing and calculation processes for establishing the adjustments. Capital Power expects that the Alberta Balancing Pool will dispute invoices related to the Sundance C PPA, which amount to a net potential exposure to Capital Power's gross receivables of approximately $25 million. However, despite this dispute, Capital Power still expects to ultimately realize the full amount of gross receivables related to the line losses.

RISKS AND RISK MANAGEMENT

Details around the Company's approach to risk management are described in the Company's 2019 Management's Discussion and Analysis. During the first nine months of 2020, the impacts of the COVID-19 pandemic have been felt throughout the world. Additionally, oil prices have declined dramatically. The current situation is dynamic, with uncertainty around the ultimate duration and magnitude of the impact on the economy. The ultimate impact on the Company is dependent on future events that are uncertain at this time; however, the key impacts of these and other developments on the Company's risk exposures as of the release date of this report and key strategies for mitigating those risks are disclosed below.

Risk area	Key risk impacts	Key risk mitigation strategies
Power price risk	Responses to the COVID-19 pandemic throughout North America have driven a reduction in demand for electricity as municipal, provincial and state authorities implemented social distancing policies, and stay-at-home and/or "shelter in place" directives. In turn, this put downward pressure on forward electricity prices for the balance of 2020 and for 2021. There is currently no certainty as to when the pandemic will be brought fully under control, but public expectations generally indicate that these impacts could continue to be felt into 2021. While it is possible that these impacts could extend further into 2021, a recovery in demand is already underway in Canada with both Alberta and Ontario progressing with opening up their economies. Both Alberta and Ontario continue to be supportive of keeping their economies open while addressing the recent increases in new cases.	Approximately half of Capital Power's net cash flows from operating activities come from facilities located outside of Alberta. These facilities are under long-term contractual arrangements with investment grade counterparties. As a result, these facilities have little exposure to the downward pressure on electricity prices as a result of lower electricity demand. The Company's thermal facility contracts typically are tolling arrangements in which most of the revenue is in the form of capacity payments that are paid regardless of the degree the plant is run. The Company's wind facilities receive fixed pricing for the power produced. In Ontario, where the lower electricity demand could result in some additional physical curtailment of wind facilities, Capital Power is held whole under the contractual arrangements even in the event of physical curtailment. The balance of the Company's net cash flows from operating activities come from Alberta generation facilities. In 2020, approximately 60% of the Company's net cash flows from operating activities from Alberta facilities are under long-term contract with investment grade counterparties, including the tolling arrangement on Shepard and the PPAs for Genesee 1 and 2 through the end of 2020. The balance of the output from the Company's Alberta facilities is sold into the Alberta merchant market, however, the Company continues to manage this exposure by entering into various purchase and sale arrangements for periods of varying duration. As at September 30, 2020, the Company's Alberta commercial baseload generation was substantially all sold forward for the remainder of 2020 which limits Capital Power's exposure to the recent drop in electricity demand. Given that most of the Company's output is hedged in 2020, coupled with maintaining high facility availability, the Company has thus far not experienced significant impacts on its generation of net cash flows from operating activities related to recent developments. For 2021, the portion of net cash flows from operating activities from Alberta facilities under long-term contracts is approximately 20%, and as at September 30, 2020, the balance of the Company's Alberta commercial baseload generation not under long-term contract was 13% sold forward for 2021. The relatively lower percentage sold forward for 2021 is driven by lower than normal liquidity and the gap between forward pricing and management's pricing expectations for 2021. The lower than normal liquidity and gap in price expectations are likely driven by uncertainty due to a number of factors including (i) impacts of the expiry of PPAs shifting more market share offer control from the Alberta Balancing Pool to commercial entities, (ii) continued impacts of COVID-19 and oil price reduction on demand, and (iii) carbon pricing. Despite the lower than typical percentage sold forward for the upcoming year, the Company continues to follow the same risk mitigation strategies as described in the Company's 2019 Management's Discussion and Analysis. In line with these risk mitigation strategies, the Company will be balancing the risks associated with being exposed to a higher volume of fluctuations in power prices with the risk of missing opportunities to sell power at higher expected prices in future periods. During the second quarter of 2020, the Company updated its long-range forecasting and, given the prolonged nature of COVID-19 and oil pricing impacts, deemed the combined impact of the noted factors to be a triggering event to assess the Alberta CGU for potential asset impairment. Impairment testing on the Alberta CGU was completed in the second quarter of 2020 with no impairment required.

Risk area	Key risk impacts	Key risk mitigation strategies
Fuel supply and price risk	The reduction in oil prices in 2020 has driven a reduction in oil production which also impacts natural gas production tied to oil drilling. These reductions in natural gas supply have put upward pressure on natural gas prices for the balance of 2020 and beyond.	The Company's portfolio of generation comes from a variety of fuel types which minimizes exposure to any one fuel type. For natural gas, the Company uses long-term supply agreements including natural gas contracts as well as fixed transportation agreements to manage its exposure to increases in natural gas prices. As at September 30, 2020, the Company has economically hedged substantially all of its expected natural gas burn for the remainder of 2020 and 2021, and as a result does not anticipate significant fuel price risk in 2020 and 2021.
Operations and maintenance of equipment risk	With the spread of COVID-19, it is possible that staffing levels at our facilities in the future could be limited by the availability of healthy staff at each facility. Ongoing maintenance activities at our facilities may also be limited by the availability of employees and required external service providers under long-term service agreements. The latter, as well as the timely availability of parts and equipment, may also be impacted by cross-border travel and transportation restrictions.	The Company continues to place the utmost importance on health and safety for its employees. The Company has enacted the following additional measures for all locations: • additional cleaning and sanitizing of our sites and critical operations centres; • the implementation of a COVID-19 "Fit for Duty" questionnaire and a screening process that all employees and contractors must clear before being allowed on site; • limited group contact by segregating our shift changes and breaks at our thermal facilities; • scaled back to pairs (instead of larger teams) working at our renewable sites; and • restricted access to sites by prohibiting visitors and non-essential personnel. Management teams across the Company are also actively enhancing and acting on contingency and business continuity plans to ensure critical workers have the knowledge, support and resources they need to continue to perform their functions under many different scenarios. Thus far, the efforts noted above have successfully contributed to a safe and healthy workforce at Capital Power. In addition, Capital Power also actively engaged with government officials, security and reliability networks, service providers and other peer groups to ensure that the Company's power generation operations and personnel were covered by relevant essential services designations developed by governments as part of their response to the COVID-19 situation. These designations minimized the likelihood of any disruption to our ability to generate power.
	Having found that the bulk power system (BPS) is a potential target for malicious terrorist acts against the United States, President Trump issued an Executive Order on May 1, 2020 entitled, and declared a "national emergency" with respect to threats to the BPS via equipment manufactured in countries deemed to be "foreign adversaries". Early interpretations of the Executive Order suggest that its primary focus will be on substations and related transmission equipment, although the consensus view is that the Executive Order is drafted so broadly that further assurances are needed.	Management will continue to monitor developments around this Executive Order and any potential impacts on the Company.

Risk area	Key risk impacts	Key risk mitigation strategies
People risk	The ability of the Company to maintain reliable operations of its facilities and meet ongoing obligations is dependent on the ability of our workforce to continue to function normally and remain healthy.	The Company has enacted its Business Continuity Plan. In line with the plan, the Company is connected with, and is following all guidelines from, all relevant authorities governing the areas in which the Company operates. All essential staff required on operating sites are practicing health and safety measures designed to limit the potential for spreading illness as described above. All other employees are working from home and all employees have been asked to practice social distancing. Inclusion of Capital Power's operations and personnel as part of provincial, state and/or national essential service designations, as described above, will also minimize the likelihood of disruption to our ability to generate power.
Finance risk – liquidity risk	The potential for ongoing volatility in financial markets will create additional uncertainty when accessing capital.	Capital Power's current liquidity remains strong and the Company was able to complete an offering of medium-term notes which closed on October 1, 2020 and covered the refinancing of medium-term notes that were to mature later in the year. Additionally, the Company also continues to have available committed credit facilities to draw upon (see Liquidity and Capital Resources). To date in 2020, the Company has not experienced and does not anticipate significant unfavorable impacts to liquidity driven by recent market developments.
Finance risk – counterparty credit risk	As a result of the economic impacts of both COVID-19 and the reduction in the price of oil, the risk that certain of the Company's counterparties will be unable to satisfy their contractual obligations has increased. Increased exposures include trade and other receivables on certain commercial and industrial customers as well as derivative financial instruments assets related to emissions portfolio trading.	The Company continues to actively monitor its exposure to counterparty credit risk and recorded an allowance of less than $1 million during the first nine months of 2020 for expected credit losses on trade and other receivables. Additionally, the Company has reflected increases in counterparty credit risk exposure within its fair value measurements of derivative financial instruments. The Company continues to deal largely with creditworthy counterparties and uses credit enhancements such as cash deposits, prepayments, parent company guarantees, bank letters of credit, master netting agreements, margin accounts and credit derivatives to further mitigate counterparty credit risk.
Foreign exchange risk	As a result of the current economic uncertainty created by the pandemic and the reduction in the price of oil, the Canadian dollar has weakened notably as compared to the U.S. dollar in the first quarter followed by a partial recovery during the second and third quarters of 2020. These fluctuations affect the Company's capital and operating costs, revenues and cash flows and unfavourable fluctuations can adversely impact the Company's financial performance.	For the Company's facilities that have a U.S. functional currency, foreign exchange movements are largely matched within its U.S. operations and hence foreign exchange exposure is mitigated. The largest exposure the Company currently has to foreign exchange movements is related to capital costs for the Whitla Wind 2 and 3 project. The Company entered into economic hedges on those capital costs during 2020 and 2021 to mitigate that exposure.
Other unexpected events risk	The uncertainty driven by COVID-19 and the reductions in the price of oil have impacted numerous risks of the Company as outlined above. In addition, the Company has experienced increased price volatility in the environmental commodity markets.	The Company continues to trade within approved limits prescribed by the Company's Board of Directors and monitors such compliance on an ongoing basis. The Company also continues to monitor the impacted markets and will manage the environmental commodity portfolio accordingly to mitigate the exposure created by this price volatility.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $432 million as at September 30, 2020 ($356 million as at December 31, 2019) 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 changes.

The Company has forward contracts to purchase environmental credits totaling $506 million and forward contracts to sell environmental credits totaling $576 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

Alberta

In October 2019, the Government of Alberta (GOA) replaced the Carbon Competitiveness Incentive Regulation (CCIR) with the Technology Innovation and Emissions Reduction (TIER) Regulation effective January 1, 2020. This new Regulation and its impact on the electricity sector is very comparable to the CCIR. In December 2019, Environment and Climate Change Canada announced that the TIER Regulation met the federal government's stringency benchmark criteria for carbon-pollution pricing systems for 2020 for the emission sources they cover (large emitters). As such, Alberta's large emitters are not subject to the Federal Carbon Pricing Backstop. However, in response to the absence of an economy wide carbon levy for all emitters, federal Greenhouse Gas Pollution Pricing Act (GGPPA) Regulations were amended to implement charges on fossil fuels in Alberta beginning January 1, 2020. This effectively ensured sources not covered under the TIER Regulation (smaller emitters) were addressed.

The governments of Alberta, Saskatchewan, Manitoba and Ontario have put forward constitutional challenges of the GGPPA. On February 24, 2020, Alberta's Court of Appeal released its decision that the GGPPA is unconstitutional which was a different decision than Saskatchewan's and Ontario's Appellate Courts. The Supreme Court of Canada heard the appeals on September 22 and 23, 2020. The timing for its ruling on the matter is unknown.

In the fall of 2019, the GOA requested that the AESO provide advice on Alberta's market power mitigation and pricing frameworks. On April 23, 2020 the GOA announced that their review of the province's existing market power mitigation framework found that it effectively protects against excessive market control. The AESO's advice on the pricing framework was provided to the GOA on July 31, 2020 and recommended no changes to the current pricing framework. The GOA accepted the AESO's advice on August 28, 2020, noting that this will ensure continued stability for Alberta's electricity market – benefitting power consumers and helping to attract further private investment and innovation.

Ontario

Ontario's Independent Electric System Operator (IESO) announced in July 2019 that it was cancelling further work on a broad capacity market framework. In reviewing its long-term planning outlook, the IESO advised that it expects only a limited need for new capacity over the next ten-year period particularly if resources are re-acquired when their existing contracts expire. Work on a capacity auction of more limited scope continued for the remainder of 2019 but in April 2020, the IESO suspended this process due to COVID-19 related impacts on demand for electricity in the province. In September 2020, the IESO initiated a Resource Adequacy Engagement (RA Engagement) that will consider a combination of bilateral contract extensions and competitive processes for medium to long-term needs. These procurement mechanisms are expected by the IESO to be implemented alongside the expansion of the province's existing demand response auction, which will serve as the IESO-administered auction for the procurement of capacity over the short term. The Company understands that the potential framework for re-contracting of assets, including those assets owned by the Company, will be considered as part of the RA Engagement process.

On November 6, 2019 the Ontario government issued a directive requiring the IESO to retain a third party and undertake a targeted review of existing large gas and wind generation contracts to identify opportunities to lower overall electricity costs. An IESO report on key findings and recommendations resulting from the review was provided to the Ontario government in late February 2020. As part of this process, the IESO sought the perspectives of contract counterparties, including Capital Power, on potential cost-savings opportunities. The IESO released the third-party report in August 2020. A number of restructuring options were considered, none of which identified opportunities for unilateral contract termination or amendment of terms.

The IESO has published several first drafts of proposed detailed energy market design changes for stakeholder consultation over the course of 2020. These proposed changes are expected to evolve over the remainder of the year through the IESO's engagement process. Consequently, amendments to existing generation contracts are likely, though the impact to these contracts, including those of the Company, are unknown until the detailed market changes are finalized and the contract amendment process is complete.

On September 21, 2020, the Ontario Minister of the Environment, Conservation and Parks (MECP) announced that the Federal government has accepted Ontario's Emissions Performance Standards (EPS) as an alternative to the federal carbon pricing regime. MECP is working with the federal government to transition industry to the EPS. Timing of the transition has not yet been established and is currently unknown. Until the transition is completed, York Energy, East Windsor and Goreway remain subject to the federal GGPPA and the federal carbon price of $30/tonne in 2020. The contracts for these facilities have provisions that trigger amendments, the effect of which will enable recovery of at least some of the imposed federal carbon compliance costs. Though there is limited risk the Company may incur some of the compliance costs with this program, the Company does not believe the implementation of a federal carbon pricing system or any potential provincial greenhouse gas system will have a material adverse effect on its financial condition and results of operations.

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, 2019 MD&A.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at September 30, 2020 and December 31, 2019 were as follows:

(unaudited, $ millions)		September 30, 2020		December 31, 2019	
	Fair value hierarchy level [1]	**Carrying amount**	**Fair value**	**Carrying amount**	**Fair value**
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	130	130	248	248
Trade and other receivables [2]	N/A	430	430	281	281
Government grant receivable [3]	Level 2	438	447	476	435
Fair value through income or loss					
Derivative financial instruments assets – current and non-current	See below	341	341	234	234
Fair value through other comprehensive income					
Derivative financial instruments assets – current and non-current	See below	5	5	-	-
Financial liabilities:					
Other financial liabilities					
Trade and other payables	N/A	434	434	301	301
Loans and borrowings [3]	Level 2	3,422	3,663	3,413	3,505
Fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See below	216	216	192	192
Fair value through other comprehensive income					
Derivative financial instruments liabilities – current and non-current	See below	134	134	106	106

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

2 Excludes current portion of government grant receivable.

3 Includes current portion.

Risk management and hedging activities

There have been no material changes in the nine months ended September 30, 2020 to the Company's risk management and hedging activities as described in the Company's December 31, 2019 MD&A.

The derivative financial instruments assets and liabilities held at September 30, 2020 compared with December 31, 2019 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at September 30, 2020					
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Foreign exchange cash flow hedges**	**Foreign exchange non-hedges**	**Total**
Derivative financial instruments assets	Level 2	4	277	1	-	-	282
	Level 3	-	64	-	-	-	64
		4	341	1	-	-	346
Derivative financial instruments liabilities	Level 2	(11)	(195)	(114)	(9)	(1)	(330)
	Level 3	-	(20)	-	-	-	(20)
		(11)	(215)	(114)	(9)	(1)	(350)
Net derivative financial instruments (liabilities) assets		**(7)**	**126**	**(113)**	**(9)**	**(1)**	**(4)**

(unaudited, $ millions)		As at December 31, 2019				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 2	-	191	-	2	193
	Level 3	-	41	-	-	41
		-	232	-	2	234
Derivative financial instruments liabilities	Level 2	(23)	(192)	(83)	-	(298)
	Level 3	-	-	-	-	-
		(23)	(192)	(83)	-	(298)
Net derivative financial instruments (liabilities) assets		**(23)**	**40**	**(83)**	**2**	**(64)**

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) income 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 (loss) 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 nine months ended September 30, 2020 that have materially affected or are reasonably likely to materially affect the Company's disclosures of required information and internal control over financial reporting.

SUMMARY OF QUARTERLY RESULTS

(GWh)	Three months ended							
Electricity generation	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**
Total generation	6,327	5,472	5,562	6,437	6,808	5,500	5,782	5,406
Alberta commercial facilities								
Genesee 3	1,014	926	913	1,015	492	502	500	372
Keephills 3	N/A	N/A	N/A	N/A	450	433	470	483
Clover Bar Energy Centre 1, 2 and 3	98	79	196	135	348	264	296	264
Joffre	171	132	186	187	150	205	232	212
Shepard Energy Centre	784	770	867	660	782	679	807	769
Halkirk	117	121	148	129	86	107	120	130
Clover Bar Landfill Gas	1	1	1	-	-	-	-	-
	2,185	2,029	2,311	2,126	2,308	2,190	2,425	2,230
Alberta contracted facilities								
Genesee 1	739	689	792	848	803	556	837	877
Genesee 2	696	618	773	826	795	698	848	850
Whitla Wind 1	170	192	238	77	N/A	N/A	N/A	N/A
	1,605	1,499	1,803	1,751	1,598	1,254	1,685	1,727
Ontario and British Columbia contracted facilities								
Island Generation	47	-	7	8	379	166	168	-
York Energy	4	3	4	5	3	4	4	2
East Windsor	2	2	1	4	2	3	2	1
Goreway	329	217	143	157	304	76	N/A	N/A
K2 Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	70
Kingsbridge 1	15	21	32	34	15	20	36	33
Port Dover and Nanticoke	53	70	90	84	46	65	99	78
Quality Wind	108	99	122	130	73	77	74	112
EnPower	2	3	10	10	3	5	5	3
	560	415	409	432	825	416	388	299
U.S. contracted facilities								
Roxboro, North Carolina	84	84	81	86	88	88	62	74
Southport, North Carolina	100	114	105	127	112	121	99	106
Decatur Energy, Alabama	665	327	124	656	709	372	408	674
Arlington Valley, Arizona	693	404	377	912	878	750	394	87
Beaufort Solar, North Carolina	8	8	6	6	8	9	6	5
Bloom Wind, Kansas	154	212	183	197	176	169	175	164
Macho Springs, New Mexico	21	43	35	29	21	43	39	31
New Frontier Wind, North Dakota	95	102	110	115	85	88	101	9
Cardinal Point Wind, Illinois	86	138	18	N/A	N/A	N/A	N/A	N/A
Buckthorn Wind, Texas	71	97	N/A	N/A	N/A	N/A	N/A	N/A
	1,977	1,529	1,039	2,128	2,077	1,640	1,284	1,150

(%)	Three months ended							
Facility availability	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**
Total average facility availability	98	92	91	94	96	92	96	94
Alberta commercial facilities								
Genesee 3	100	95	92	100	96	100	100	74
Keephills 3	N/A	N/A	N/A	N/A	93	92	99	100
Clover Bar Energy Centre 1, 2 and 3	98	90	97	86	96	91	97	85
Joffre	99	100	93	89	82	100	100	100
Shepard Energy Centre	100	99	100	79	100	86	97	100
Halkirk	96	99	98	99	95	98	98	98
Clover Bar Landfill Gas	37	48	53	-	-	-	-	-
	99	96	96	90	95	93	98	93
Alberta contracted facilities								
Genesee 1	100	100	96	100	96	72	100	100
Genesee 2	100	97	97	100	100	95	100	98
Whitla Wind 1	98	97	97	97	N/A	N/A	N/A	N/A
	99	98	97	100	98	83	100	99
Ontario and British Columbia contracted facilities								
Island Generation	100	100	100	92	99	100	100	100
York Energy	98	100	100	94	99	100	100	100
East Windsor	99	96	99	97	99	99	99	99
Goreway	93	96	88	88	87	99	N/A	N/A
K2 Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	99
Kingsbridge 1	98	98	99	99	98	97	98	99
Port Dover and Nanticoke	93	99	99	97	94	100	99	98
Quality Wind	98	98	96	98	96	98	96	95
EnPower	100	74	86	91	72	97	55	97
	96	97	93	91	92	99	98	99
U.S. contracted facilities								
Roxboro, North Carolina	99	99	90	88	99	100	88	97
Southport, North Carolina	98	100	85	96	84	90	91	83
Decatur Energy, Alabama	100	73	87	93	100	81	98	85
Arlington Valley, Arizona	99	77	66	99	100	100	81	94
Beaufort Solar, North Carolina	99	100	100	98	100	100	100	97
Bloom Wind, Kansas	95	98	99	99	98	98	99	100
Macho Springs, New Mexico	97	98	99	98	97	99	98	99
New Frontier Wind, North Dakota	97	98	98	94	97	95	96	98
Cardinal Point Wind, Illinois	92	95	89	N/A	N/A	N/A	N/A	N/A
Buckthorn Wind, Texas	94	95	N/A	N/A	N/A	N/A	N/A	N/A
	98	82	83	96	99	91	92	89

Financial results

(unaudited, $ millions)	Three months ended							
	Sep 30 2020	Jun 30 2020	Mar 31 2020	Dec 31 2019	Sep 30 2019	Jun 30 2019	Mar 31 2019	Dec 31 2018
Revenues and other income								
Alberta commercial facilities and portfolio optimization	208	180	207	214	181	150	180	150
Alberta contracted facilities	73	70	79	73	68	46	74	71
Ontario and British Columbia contracted facilities [3]	92	88	100	102	88	56	47	52
U.S. contracted facilities	133	117	101	103	149	102	95	63
Corporate [1]	13	12	11	141	15	17	15	13
Unrealized changes in fair value of commodity derivatives and emission credits	(66)	(32)	35	50	16	(5)	(14)	(9)
	453	**435**	**533**	**683**	**517**	**366**	**397**	**340**
Adjusted EBITDA								
Alberta commercial facilities and portfolio optimization	80	60	81	80	72	71	84	62
Alberta contracted facilities	56	53	59	57	49	32	53	53
Ontario and British Columbia contracted facilities [2, 3]	69	70	80	77	63	48	44	52
U.S. contracted facilities	96	56	31	40	115	54	38	25
Corporate	(17)	(22)	(17)	98	(15)	(14)	(17)	(21)
	284	**217**	**234**	**352**	**284**	**191**	**202**	**171**

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 quarter values include Capital Power's share of K2 Wind which was disposed of effective December 31, 2018.

3 Fiscal 2018 quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16.

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

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Sep 30 2020	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**
Revenues and other income [4]	453	435	533	683	517	366	397	340
Adjusted EBITDA [1, 2, 4]	284	217	234	352	284	191	202	171
Net income (loss) [4]	106	23	-	181	(228)	106	60	136
Net income (loss) attributable to shareholders of the Company [4]	108	23	2	182	(226)	108	61	138
Basic earnings (loss) per share ($) [4]	0.89	0.10	(0.11)	1.61	(2.25)	0.93	0.49	1.24
Diluted earnings (loss) per share ($)[3, 4]	0.89	0.09	(0.11)	1.60	(2.25)	0.92	0.49	1.24
Normalized earnings per share ($) [1, 4]	0.66	0.17	0.27	0.29	0.60	0.14	0.29	0.30
Net cash flows from operating activities	258	91	103	201	209	114	196	133
Adjusted funds from operations [1]	221	97	118	128	225	85	117	80
Adjusted funds from operations per share ($) [1]	2.10	0.92	1.12	1.22	2.11	0.82	1.15	0.78
Purchase of property, plant and equipment and other assets	50	87	99	112	193	279	51	114

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 quarter values include Capital Power's share of K2 Wind which was disposed of effective December 31, 2018.

3 Diluted earnings (loss) per share was calculated after giving effect to outstanding share purchase options.

4 Fiscal 2018 quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16.

	Three months ended							
Spot price averages	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**
Alberta power ($ per MWh)	44	30	67	47	47	57	69	56
Alberta natural gas (AECO) ($ per Gj)	2.17	1.90	1.99	2.32	0.99	1.17	2.62	1.59
Capital Power's Alberta portfolio average realized power price ($ per MWh)	59	53	62	57	59	55	58	52

Factors impacting results for the previous quarters

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

For the quarter ended June 30, 2020, the Company recorded net income attributable to shareholders of $23 million compared to net income attributable to shareholders of $108 million for the quarter ended June 30, 2019. Decreases in net income in the second quarter of 2020 were driven partly by unrealized losses on commodity derivatives and emission credits of $9 million in the second quarter of 2020 compared with unrealized gains of $48 million in the second quarter of 2019. This was most notably due to unrealized losses in the second quarter of 2020 due to the reversal of prior period unrealized gains for trades settled in the period as compared to unrealized gains in the comparative period of 2019. The prior period gains were largely the result of increasing Alberta power prices on Alberta power derivative forward purchase contracts and the impact of decreasing forward prices on forward sales contracts for the Company's U.S. wind facilities. Higher net finance expense in the second quarter of 2020 also contributed to lower net income and was due to financing related to the acquisitions of Buckthorn Wind (see Significant Events) and Goreway in second quarters of 2020 and 2019, respectively, and tax equity financing related to Cardinal Point Wind (see Significant Events) that commenced commercial operations in the first quarter of 2020. In addition, the second quarter of 2020 had higher income tax expense mainly due to a decrease in the Alberta corporate income tax rate that resulted in a deferred income tax recovery of $51 million in the second quarter of 2019, of which there is no comparable tax recovery recognized in the second quarter of 2020. Partially offsetting these decreases was higher adjusted EBITDA, mainly from the acquisitions of Goreway in the second quarter of 2019 and Buckthorn Wind in the second quarter of 2020, and commencement of operations of Whitla Wind 1 in the fourth quarter of 2019 and Cardinal Point Wind late in the first quarter of 2020.

For the quarter ended March 31, 2020, the Company recorded net income attributable to shareholders of $2 million compared to net income attributable to shareholders of $61 million for the quarter ended March 31, 2019. Decreases in net income in the first quarter of 2020 were driven partly by unrealized losses on commodity derivatives and emission credits being $52 million higher than in the first quarter of 2019. This was most notably due to unrealized losses in the first quarter of 2020 due to the reversal of prior period unrealized gains for trades settled in the period as compared to unrealized gains in the comparative period of 2019 most notably on the reversal of prior period unrealized losses on natural gas derivatives settled during the three months ended March 31, 2019. In addition, the first quarter of 2020 had higher depreciation and amortization primarily due to the acquisition of Goreway in the second quarter of 2019, Whitla Wind 1 commencing commercial operations in the fourth quarter of 2019 and losses on the discontinuation of the Genesee 4 and 5 project recorded in the quarter. Partially offsetting these decreases was higher adjusted EBITDA, mainly from the acquisition of Goreway in the second quarter of 2019 and commencement of operations of Whitla Wind 1 in the fourth quarter of 2019 and lower income tax expense primarily due to lower consolidated income before tax.

For the quarter ended December 31, 2019, the Company recorded net income attributable to shareholders of $182 million compared to net income attributable to shareholders $138 million for the quarter ended December 31, 2018. Gains in the fourth quarter of 2019 related to the Genesee 3 and Keephills 3 swap transaction were largely offset by the gain on disposal of the Company's minority owned interest in K2 Wind during the fourth quarter of 2018. Increases in net income in the fourth quarter of 2019 were driven partly by unrealized gains on commodity derivatives and emission credits being $81 million higher than in the comparable 2018 period, most notably related to the impact of decreasing forward prices on forward sales contracts for the Company's U.S. wind facilities. In addition, adjusted EBITDA was higher as a result of the 2019 addition of Goreway and the acquisition of Arlington Valley and commercial operation of New Frontier Wind in the fourth quarter of 2018 as well as higher Alberta commercial EBITDA on higher captured pricing. Partially offsetting these increases was a corresponding increase in depreciation driven by the noted asset additions. Further offsetting the increases in net income were higher tax expenses in the fourth quarter of 2019 primarily due to recognition of deferred income tax expense on the one-time adjustment to accelerate the recognition of deferred government grant revenue upon close of the Genesee 3 and Keephills 3 swap transaction, partially offset by the reversal of deferred income tax expense on the disposal of Keephills 3.

For the quarter ended September 30, 2019, the Company recorded net loss attributable to shareholders of $226 million compared to net income attributable to shareholders of $18 million for the quarter ended September 30, 2018. The decrease was largely due to pre-tax impairment of $401 million on Keephills 3 upon classification as an asset held for sale. Further contributing to the decrease was higher depreciation and amortization due to New Frontier Wind commencing commercial operation in the last quarter of 2018 and the acquisitions of Arlington Valley and Goreway in the last quarter of 2018 and second quarter of 2019, respectively, partly offset by depreciation for Keephills 3 ceasing following its classification as held for sale in August 2019. Higher net loss attributable to shareholders was partially offset by an increase in adjusted EBITDA, most notably due to the addition of Goreway and Arlington Valley and commencement of operations at New Frontier Wind, as well as an increase in unrealized gains on commodity derivatives and emission credits, which were $43 million higher in the third quarter of 2019 compared to the third quarter of 2018. In addition, income tax recovery for the third quarter of 2019 was $66 million compared to income tax expense of $7 million for the third quarter of 2018, primarily due to the recognition of a deferred tax recovery on the impairment of Keephills 3.

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

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

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

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

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

	Three months ended							
	Sep 30 2020	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**
Share price ($/common share)								
High	30.28	29.92	38.88	35.09	31.43	32.25	32.44	29.79
Low	26.57	23.24	20.23	30.13	29.31	29.60	26.22	25.33
Close	29.39	27.98	27.15	34.39	30.68	30.15	31.30	26.59
Volume of shares traded (millions)	21.6	29.5	31.8	21.3	18.2	19.6	18.0	25.5

Outstanding share and partnership unit data

As at October 28, 2020, the Company had 105.228 million common shares, 5 million Cumulative Rate Reset Preference Shares (Series 1), 6 million Cumulative Rate Reset Preference Shares (Series 3), 8 million Cumulative Rate Reset Preference Shares (Series 5), 8 million Cumulative Minimum Rate Reset Preference Shares (Series 7), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 9), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 11), and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares as at October 28, 2020 were 108.367 million. The outstanding special limited voting share is held by EPCOR.

As at October 28, 2020, CPLP had 24.040 million general partnership units outstanding and 89.473 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

ADDITIONAL INFORMATION

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

Condensed Interim Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(Unaudited, in millions of Canadian dollars)
Nine months ended September 30, 2020 and 2019

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Nine months ended September 30, 2020 and 2019

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2020	Three months ended September 30, 2019	Nine months ended September 30, 2020	Nine months ended September 30, 2019
Revenues	$ 421	$ 484	$ 1,322	$ 1,183
Other income	32	33	99	97
Energy purchases and fuel	(41)	(126)	(376)	(221)
Gross margin	412	391	1,045	1,059
Other raw materials and operating charges	(34)	(37)	(120)	(106)
Staff costs and employee benefits expense	(45)	(41)	(127)	(121)
Depreciation and amortization	(115)	(135)	(369)	(355)
Impairment	-	(401)	-	(401)
Other administrative expense	(24)	(27)	(77)	(84)
Foreign exchange gain (loss)	1	(1)	(5)	(5)
Operating income (loss)	195	(251)	347	(13)
Net finance expense	(47)	(42)	(140)	(115)
Income (loss) from joint venture	2	(1)	(5)	(3)
Income (loss) before tax	150	(294)	202	(131)
Income tax (expense) recovery (note 5)	(44)	66	(73)	69
Net income (loss)	$ 106	$ (228)	$ 129	$ (62)
Attributable to:				
Non-controlling interests	$ (2)	$ (2)	$ (4)	$ (5)
Shareholders of the Company	$ 108	$ (226)	$ 133	$ (57)

Earnings (loss) per share (attributable to common shareholders of the Company):

	Three months 2020	Three months 2019	Nine months 2020	Nine months 2019
Basic (note 6)	$ 0.89	$ (2.25)	$ 0.87	$ (0.90)
Diluted (note 6)	$ 0.89	$ (2.25)	$ 0.87	$ (0.90)

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2020	Three months ended September 30, 2019	Nine months ended September 30, 2020	Nine months ended September 30, 2019
Net income (loss)	$ 106	$ (228)	$ 129	$ (62)
Other comprehensive (loss) income:				
Items that will not be reclassified subsequently to net income (loss):				
Defined benefit plans:				
Actuarial gains[1]	-	-	3	-
Items that are or may be reclassified subsequently to net income (loss):				
Cash flow hedges:				
Unrealized gains (losses) on derivative instruments[2]	3	19	(5)	(53)
Reclassification of (gains) losses on derivative instruments to income (loss) for the period[3]	(11)	(6)	(20)	14
Net investment in foreign subsidiaries:				
Unrealized (losses) gains[4]	(18)	11	29	(22)
Total items that are or may be reclassified subsequently to net income (loss), net of tax	(26)	24	4	(61)
Total other comprehensive (loss) income, net of tax	(26)	24	7	(61)
Total comprehensive income (loss)	$ 80	$ (204)	$ 136	$ (123)
Attributable to:				
Non-controlling interests	$ (2)	$ (2)	$ (4)	$ (5)
Shareholders of the Company	$ 82	$ (202)	$ 140	$ (118)

[1] For the three and nine months ended September 30, 2020, net of income tax expense of nil and $1. For the three and nine months ended September 30, 2019, net of income tax expense of nil.

[2] For the three and nine months ended September 30, 2020, net of income tax expense of $2 and income tax recovery of $1, respectively. For the three and nine months ended September 30, 2019, net of income tax expense of $5 and income tax recovery of $16, respectively.

[3] For the three and nine months ended September 30, 2020, net of reclassification of income tax expense of $3 and $6, respectively. For the three and nine months ended September 30, 2019, net of reclassification of income tax expense of $2 and reclassification of income tax recovery of $4, respectively.

[4] For the three and nine months ended September 30, 2020, net of income tax expense of $1 and income tax recovery of $1, respectively. For the three and nine months ended September 30, 2019, net of income tax expense of nil.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	September 30, 2020	December 31, 2019
Assets		
Current assets:		
Cash and cash equivalents	$ 130	$ 248
Trade and other receivables	483	334
Inventories	195	203
Derivative financial instruments assets (note 7)	121	83
	929	868
Non-current assets:		
Other assets	54	53
Derivative financial instruments assets (note 7)	225	151
Government grant receivable	385	423
Deferred tax assets	22	24
Equity-accounted investment in joint venture	119	132
Right-of-use assets	130	95
Intangible assets	751	760
Property, plant and equipment	6,255	6,089
Goodwill	35	35
Total assets	$ 8,905	$ 8,630
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 434	$ 301
Derivative financial instruments liabilities (note 7)	144	180
Loans and borrowings (note 8)	682	857
Deferred revenue and other liabilities	62	60
Provisions	30	41
	1,352	1,439
Non-current liabilities:		
Derivative financial instruments liabilities (note 7)	206	118
Loans and borrowings (note 8)	2,740	2,556
Lease liabilities	141	105
Deferred revenue and other liabilities	357	383
Deferred tax liabilities	602	512
Provisions	471	416
	4,517	4,090
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 9)	3,438	3,441
Deficit	(410)	(347)
Other reserves	(23)	(30)
Deficit and other reserves	(433)	(377)
	3,005	3,064
Non-controlling interests	31	37
Total equity	3,036	3,101
Total liabilities and equity	$ 8,905	$ 8,630

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 9)	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, 2020	$ 3,441	$ (10)	$ (16)	$ (15)	$ 11	$ (347)	$ 3,064	$ 37	$ 3,101
Net income (loss)	-	-	-	-	-	133	133	(4)	129
Other comprehensive (loss) income:									
Defined benefit plan actuarial gain	-	-	-	4	-	-	4	-	4
Cash flow derivative hedge losses	-	(6)	-	-	-	-	(6)	-	(6)
Reclassification of gains to net income	-	(26)	-	-	-	-	(26)	-	(26)
Unrealized gains on foreign currency translation	-	-	28	-	-	-	28	-	28
Tax on items recognized directly in equity	-	7	1	(1)	-	-	7	-	7
Other comprehensive (loss) income	$ -	$ (25)	$ 29	$ 3	$ -	$ -	$ 7	$ -	$ 7
Total comprehensive (loss) income	-	(25)	29	3	-	133	140	(4)	136
Distributions to non-controlling interests	-	-	-	-	-	-	-	(2)	(2)
Common share dividends (note 9)	-	-	-	-	-	(155)	(155)	-	(155)
Preferred share dividends (note 9)	-	-	-	-	-	(39)	(39)	-	(39)
Tax on preferred share dividends	-	-	-	-	-	(2)	(2)	-	(2)
Common shares purchased	(10)	-	-	-	-	-	(10)	-	(10)
Share options exercised	7	-	-	-	-	-	7	-	7
Equity as at September 30, 2020	$ 3,438	$ (35)	$ 13	$ (12)	$ 11	$ (410)	$ 3,005	$ 31	$ 3,036

[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 9)	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	$ 3,200	$ 7	$ 23	$ (9)	$ 11	$ (222)	$ 3,010	$ 43	$ 3,053
Impact of IFRS 16 lessee accounting policy change	-	-	-	-	-	(8)	(8)	-	(8)
Tax impact of IFRS 16 lessee accounting policy change	-	-	-	-	-	2	2	-	2
Adjusted equity as at January 1, 2019	$ 3,200	$ 7	$ 23	$ (9)	$ 11	$ (228)	$ 3,004	$ 43	$ 3,047
Net loss	-	-	-	-	-	(57)	(57)	(5)	(62)
Other comprehensive (loss) income:									
Cash flow derivative hedge losses	-	(69)	-	-	-	-	(69)	-	(69)
Reclassification of losses to net loss	-	18	-	-	-	-	18	-	18
Unrealized losses on foreign currency translation	-	-	(22)	-	-	-	(22)	-	(22)
Tax on items recognized directly in equity	-	12	-	-	-	-	12	-	12
Other comprehensive loss	$ -	$ (39)	$ (22)	$ -	$ -	$ -	$ (61)	$ -	$ (61)
Total comprehensive loss	-	(39)	(22)	-	-	(57)	(118)	(5)	(123)
Common share dividends (note 9)	-	-	-	-	-	(145)	(145)	-	(145)
Preferred share dividends (note 9)	-	-	-	-	-	(36)	(36)	-	(36)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Issue of share capital	300	-	-	-	-	-	300	-	300
Share issue costs	(11)	-	-	-	-	-	(11)	-	(11)
Deferred taxes on share issue costs	1	-	-	-	-	-	1	-	1
Common shares purchased	(60)	-	-	-	-	-	(60)	-	(60)
Share based payments	-	-	-	-	1	-	1	-	1
Share options exercised	20	-	-	-	(1)	-	19	-	19
Equity as at September 30, 2019	$ 3,450	$ (32)	$ 1	$ (9)	$ 11	$ (467)	$ 2,954	$ 38	$ 2,992

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

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Nine months ended September 30,	
	2020	2019
Cash flows from operating activities:		
Net income (loss)	$ 129	$ (62)
Non-cash adjustments to reconcile net income (loss) to net cash flows from operating activities:		
Impairment	-	401
Depreciation and amortization	369	355
Net finance expense	140	115
Fair value changes on commodity derivative instruments and emission credits held for trading	(4)	(90)
Foreign exchange losses	5	5
Income tax expense (recovery)	73	(69)
Loss from joint venture	5	3
Recognition of government grant deferred revenue	(32)	(41)
Tax equity attributes	(63)	(45)
Other items	8	8
Change in fair value of derivative instruments reflected as cash settlement	(26)	36
Distributions received from joint venture	8	9
Interest paid	(101)	(83)
Income taxes paid	(38)	(4)
Other cash items	(33)	(45)
Change in non-cash operating working capital	12	26
Net cash flows from operating activities	452	519
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(236)	(523)
Business acquisition, net of acquired cash (note 3)	(79)	(390)
Government grant received	50	50
Other cash flows from investing activities	(1)	7
Realized gain on foreign currency derivative instruments	-	7
Change in non-cash investing working capital	(17)	111
Net cash flows used in investing activities	(283)	(738)
Cash flows (used in) from financing activities:		
Proceeds from issue of loans and borrowings	228	875
Repayment of loans and borrowings	(286)	(742)
Issue costs on loans and borrowings	(7)	(3)
Repayment of lease liabilities	(5)	(5)
Issue of share capital	-	300
Share issue costs	-	(11)
Proceeds from exercise of share options	7	19
Common shares purchased (note 9)	(10)	(60)
Dividends paid (note 9)	(190)	(175)
Capitalized interest paid	(4)	(8)
Distributions to non-controlling interests	(2)	-
Income taxes paid on preferred share dividends	(17)	(15)
Net cash flows (used in) from financing activities	(286)	175
Foreign exchange loss on cash held in foreign currency	(1)	(5)
Net decrease in cash and cash equivalents	(118)	(49)
Cash and cash equivalents at beginning of period	248	182
Cash and cash equivalents at end of period	$ 130	$ 133

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 generation facilities and manages its related electricity, natural gas and emissions 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 2019 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 and have been prepared under the historical cost basis, except for the Company's derivative instruments, emission credits held for trading, defined benefit pension assets and cash-settled share based payments, which are stated at fair value.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on October 30, 2020.

3. Buckthorn Wind acquisition:

On April 1, 2020, the Company acquired a 100% ownership interest in Buckthorn Wind, a 101 megawatt (MW) wind facility in Texas, from co-sellers John Laing Investments and Clearway Renew LLC, a subsidiary of Clearway Energy Group LLC. The purchase price consisted of (i) $84 million (US$60 million) in total cash consideration, including working capital and other closing adjustments, (ii) the assumption of tax equity financing of $103 million (US$73 million) and (iii) contingent consideration valued at nil. Contingent consideration, to a maximum of US$8 million, would become payable in the future if certain market outcomes lead to Buckthorn Wind exceeding agreed upon thresholds. The Company considers the likelihood of contingent consideration payment to be low, resulting in no value being ascribed to the contingent consideration in the purchase price allocation. The acquisition has been accounted for as a business combination.

This acquisition supports the Company's growth strategy with long-term contracts strengthening the Company's contracted cash flow profile, while also expanding its renewables portfolio.

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

3. Buckthorn Wind acquisition, continued:

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

	April 1, 2020
Cash and cash equivalents	$ 5
Trade and other receivables	1
Derivative financial instrument assets[1]	48
Right-of-use assets	7
Property, plant and equipment	178
Trade and other payables	(2)
Loans and borrowings[1]	(103)
Lease liabilities[1]	(7)
Provisions	(6)
Deferred revenue and other liabilities[1]	(3)
Deferred tax liabilities	(34)
Fair value of net assets acquired	$ 84

[1] Includes current portion.

The purchase price allocation is preliminary, subject to the finalization of certain closing adjustments which are expected to be finalized in late 2020 or early 2021.

Buckthorn Wind has the following revenue swap arrangements (see note 10 for details on the fair value of these derivative financial instruments):

- Offtake swap: The offtake swap is a 20-year contract with an investment grade counterparty which covers 55% of the facility's output. Under this contract the Company will swap the market revenue and environmental attributes associated with the contract quantity for a fixed price per megawatt hour (MWh). There are 18 years remaining on this contract as of the acquisition date.
- Commodity swap: The commodity swap is a 13-year contract with an investment grade counterparty, with a fixed notional quantity equal to 45% of the long-term average forecasted annual production. Under this contract, the Company will swap the market revenue associated with the fixed notional quantity for a fixed price per MWh. There are 11 years remaining on this contract as of the acquisition date.

The tax-equity financing related to Buckthorn Wind represents the initial equity investment made by the project investor, adjusted for earnings, tax benefits and cash distributions paid to date. The maturity date of this obligation is subject to change and is driven by the dates on which the project investor reaches the agreed upon target rate of return.

The results of operations of Buckthorn Wind are included in the Company's consolidated statements of income (loss) and statements of changes in equity from the date of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statements of financial position. Since the acquisition date, the following revenues (net of mark to market fluctuations on derivative financial instruments), other income and net loss are included in the consolidated statements of income (loss) for the three and nine months ended September 30, 2020:

	Three months ended September 30, 2020	Nine months ended September 30, 2020
Revenues	$ 3	$ (7)
Other income	2	6
Net loss	(1)	(11)

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

3. Buckthorn Wind acquisition, continued:

The consolidated revenues and net income of the Company including Buckthorn Wind, had the acquisition occurred at January 1, 2020, would have been as follows:

	Three months ended September 30, 2020	Nine months ended September 30, 2020
Revenues	$ 421	$ 1,315
Other income	32	104
Net income	106	123

In conjunction with the acquisition of Buckthorn Wind, for the nine months ended September 30, 2020, the Company incurred $1 million in acquisition costs which have been recorded on the Company's consolidated statements of income (loss) as other administrative expenses.

4. Discontinuation of the Genesee 4 and 5 project:

During the first quarter of 2020, the Company and its partner on the Genesee 4 and 5 project determined that they would no longer be pursuing the project. Arbitration has commenced between the Company and its partner around the costs of exiting the series of agreements previously entered into. As a result of the decision to no longer pursue the project, the Company has determined that $13 million of capital expenditures incurred by the Company were purely related to the development of Genesee 4 and 5. The Company therefore recorded a write-off of these capital costs within depreciation and amortization during the first quarter of 2020.

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 September 30,		Nine months ended September 30,	
	2020	2019	2020	2019
Income (loss) before tax	$ 150	$ (294)	$ 202	$ (131)
Income tax at the statutory rate of 25%[1] (2019 – 26.5%)	38	(78)	51	(35)
(Decrease) increase resulting from:				
Non-deductible (taxable) amounts	-	(1)	2	(4)
Amounts attributable to non-controlling interests and tax-equity interests	6	5	16	14
Change in unrecognized tax benefits	(2)	-	-	1
Statutory and other rate differences[1]	-	8	1	(45)
Other	2	-	3	-
Income tax expense (recovery)	$ 44	$ (66)	$ 73	$ (69)

[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 was 26.5%, the 2020 statutory tax rate is 25%, and the statutory tax rate will decrease further to 24% for the 2021 year, and to 23% for the 2022 year.

On June 29, 2020, the Alberta Government announced, as part of Alberta's Recovery Plan, the Job Creation Tax Act will be accelerated to reduce the Alberta corporate income tax rate from 10% to 8% effective July 1, 2020. Given that this tax rate reduction to 23% has not been substantively enacted as at September 30, 2020, the above 2020 statutory tax rate has not yet been updated to 23%. On October 20, 2020, Bill 35 passed first reading in the Legislative Assembly of Alberta. Accordingly, the Alberta corporate tax rate reduction to 23% is considered substantively enacted as at October 20, 2020.

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

6. Earnings (loss) per share:

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

	Three months ended September 30,		Nine months ended September 30,	
	2020	2019	2020	2019
Income (loss) for the period attributable to shareholders	$ 108	$ (226)	$ 133	$ (57)
Preferred share dividends[1]	(14)	(14)	(41)	(37)
Earnings (loss) available to common shareholders	$ 94	$ (240)	$ 92	$ (94)
Weighted average number of common shares	105,078,412	106,465,965	105,181,400	103,975,042
Basic earnings (loss) per share	$ 0.89	$ (2.25)	$ 0.87	$ (0.90)
Weighted average number of common shares	105,078,412	106,465,965	105,181,400	103,975,042
Effect of dilutive share purchase options	448,173	-	516,786	-
Diluted weighted average number of common shares	105,526,585	106,465,965	105,698,186	103,975,042
Diluted earnings (loss) per share	$ 0.89	$ (2.25)	$ 0.87	$ (0.90)

[1] Includes preferred share dividends declared and related taxes.

(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:

	September 30, 2020					
	Energy and emission allowances		Interest rate	Foreign exchange		
	cash flow hedges	non-hedges	cash flow hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:						
Current	$ 2	$ 119	$ -	$ -	$ -	$ 121
Non-current	2	222	1	-	-	225
Derivative instruments liabilities:						
Current	(6)	(99)	(31)	(7)	(1)	(144)
Non-current	(5)	(116)	(83)	(2)	-	(206)
Net fair value	$ (7)	$ 126	$ (113)	$ (9)	$ (1)	$ (4)
Net notional buys (sells) (millions):						
Megawatt hours of electricity	(6)	(19)				
Gigajoules of natural gas purchased[1]		190				
Gigajoules of natural gas basis swaps[1]		189				
Number of renewable energy credits		(4)				
Interest rate swaps			$ 1,386			
Interest rate swaps (U.S. dollars)			$ 180			
Forward currency buys (sells) (U.S. dollars)				$ 94	$ (52)	
Range of remaining contract terms in years	0.1 to 4.3	0.1 to 17.3	0.2 to 6.3	0.5 to 1.2	0.1	

[1] The Company's natural gas trading strategy employs future purchase derivative instruments as well as basis swaps pertaining to certain of the future purchase derivative instruments, to manage its exposure to commodity price risk.

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

7. Derivative financial instruments and hedge accounting, continued:

	December 31, 2019				
	Energy and emission allowances		Interest rate		
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ -	$ 81	$ -	$ 2	$ 83
Non-current	-	151	-	-	151
Derivative instruments liabilities:					
Current	(12)	(85)	(83)	-	(180)
Non-current	(11)	(107)	-	-	(118)
Net fair value	$ (23)	$ 40	$ (83)	$ 2	$ (64)
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(7)	(14)			
Gigajoules of natural gas purchased[2]		181			
Gigajoules of natural gas basis swaps[2]		179			
Metric tons of emission allowances		4			
Number of renewable energy credits		(1)			
Interest rate swaps			$ 763	$ 100	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 13.0	0.8 to 0.9	0.9	

[2] The Company's natural gas trading strategy employs future purchase derivative instruments as well as basis swaps pertaining to certain of the future purchase derivative instruments, to manage its exposure to commodity price risk.

Fair values of derivative instruments are determined using valuation techniques, inputs, and assumptions as described in the Company's 2019 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 (loss) are:

	Three months ended September 30, 2020		Three months ended September 30, 2019	
	Unrealized (losses) gains	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (10)	$ 14	$ 14	$ 8
Energy and emission allowances non-hedges	32	18	4	22
Interest rate cash flow hedges	3	(2)	2	(1)
Foreign exchange cash flow hedges	(2)	-	-	-
Foreign exchange non-hedges	2	-	(2)	1

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

7. Derivative financial instruments and hedge accounting, continued:

	Nine months ended September 30, 2020		Nine months ended September 30, 2019	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized (losses) gains	Realized (losses) gains
Energy cash flow hedges	$ 20	$ 26	$ (41)	$ (18)
Energy and emission allowances non-hedges	9	39	92	37
Interest rate cash flow hedges[3]	(43)	(4)	(10)	(2)
Interest rate non-hedges	(2)	1	-	-
Foreign exchange cash flow hedges	(9)	-	-	-
Foreign exchange non-hedges	(1)	(2)	(11)	7

[3] Interest rate cash flow hedges of $450 million were settled in the nine months ended September 30, 2019 for a total loss of $18 million which includes $17 million deferred within accumulated other comprehensive (loss) income to be reclassified to net income (loss) 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 and losses are included in the Company's consolidated statements of income (loss) for the three and nine months ended September 30, 2020 and 2019:

	Three months ended September 30,		Nine months ended September 30,	
	2020	2019	2020	2019
Revenues	$ (30)	$ 64	$ 11	$ (12)
Energy purchases and fuel	94	(30)	63	123
Foreign exchange gain (loss)	2	(1)	(3)	(4)
Net finance expense	(2)	(1)	(5)	(2)

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices, interest rate risk relating to future borrowings and foreign exchange risk relating to future capital investment in U.S. dollars. For the three and nine months ended September 30, 2020, the ineffective portion of hedging derivatives required to be recognized in the statement of income (loss) were nil. For the three and nine months ended September 30, 2019, nil and $1 million of losses, respectively, were realized within net finance expense pertaining to the ineffective portion of hedging derivatives.

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

	September 30, 2020
Within one year	$ (13)
Between one and five years	(20)
After five years	(5)
	$ (38)

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

8. Loans and borrowings:

Medium-term note offering and early redemption of medium-term notes

On October 1, 2020 the Company closed a public offering of unsecured medium-term notes in the aggregate principal amount of $350 million (the Offering). The notes have a coupon rate of 3.147% and mature on October 1, 2032. The net proceeds of the Offering have been and will be used to repay, redeem or refinance existing indebtedness, including indebtedness under outstanding debt securities or credit facilities, or for general corporate purposes. Included in such repayments is the redemption, on October 9, 2020, of all of the Company's outstanding 5.276% medium-term notes, due November 16, 2020, in the aggregate principal amount of $251 million. The redemption price was an aggregate amount of $258 million, including applicable early redemption premiums, as well as accrued and unpaid interest to and including the day immediately preceding the redemption date.

Tax-equity financing

On March 16, 2020, Capital Power's Cardinal Point Wind project began commercial operations. Subsequently, the Company received approximately $221 million (US$157 million) in tax equity financing on March 26, 2020, net of issue costs of $3 million (US$2 million) associated with the financing, from two U.S. financial institutions in exchange for Class A interests of a subsidiary of the Company.

Tax equity financing represents the initial equity investments made by the project investors, adjusted for earnings, tax benefits and cash distributions realized/paid over time. The maturity dates of these obligations are subject to change and are driven by the dates on which the project investors reach the agreed upon target rate of return.

9. Share capital:

	Dividends declared							
	For the three months ended September 30,				For the nine months ended September 30,			
	2020		2019		2020		2019	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[1]	$ 0.5125	$ 54	$ 0.4800	$ 51	$ 1.4725	$ 155	$ 1.3750	$145
Preference								
Series 1	0.1913	1	0.1913	1	0.5738	3	0.5738	3
Series 3	0.3408	2	0.3408	2	1.0224	6	1.0224	6
Series 5	0.3274	3	0.3274	3	0.9821	9	0.9821	9
Series 7	0.3750	3	0.3750	3	1.1250	9	1.1250	9
Series 9	0.3594	2	0.3594	2	1.0781	6	1.0781	6
Series 11	0.3594	2	0.3594	2	1.0781	6	0.5366	3

[1] On July 29, 2020, the Company's Board of Directors approved an increase of 6.8% to $2.05 in the annual dividend per common share effective for the third quarter of 2020.

	Dividends paid[2]							
	For the three months ended September 30,				For the nine months ended September 30,			
	2020		2019		2020		2019	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[3]	$ 0.4800	$ 50	$ 0.4475	$ 48	$ 1.4400	$ 151	$ 1.3425	$139

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

[3] Effective for the September 30, 2020 dividend, Capital Power reinstated its dividend reinvestment plan for its common shares. The dividend reinvestment plan was previously suspended on June 30, 2015.

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

9. Share capital, continued:

During the three months ended September 30, 2020, the Company did not purchase and cancel any of its outstanding common shares under its Toronto Stock Exchange approved normal course issuer bid. During the nine months ended September 30, 2020, the Company purchased and cancelled 461,832 of its outstanding common shares at an average exercise price of $22.67 per share for $10 million (three and nine months ended September 30, 2019 – 1,635,538 and 2,018,950 common shares at an average exercise price of $30.40 and $29.66 per share for $50 million and $60 million, respectively).

10. 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 2019 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 2019 annual consolidated financial statements. The carrying amount and fair value of the Company's other financial instruments, which are all classified and subsequently measured at amortized cost, are summarized as follows:

		September 30, 2020		December 31, 2019	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets[1]					
Government grant receivable	Level 2	438	447	476	435
Financial liabilities[1]					
Loans and borrowings	Level 2	3,422	3,663	3,413	3,505

[1] Includes current portion.

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, 2019.

The fair value measurement of a financial instrument is included in only one of the three levels described in the Company's 2019 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 or change in circumstances that caused the transfer. The transfers between levels in the fair value hierarchy for the three and nine months ended September 30, 2020 and the year ended December 31, 2019 are disclosed below within the continuity of Level 3 balances.

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

10. Financial instruments, continued

Fair value hierarchy, continued

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 2019 annual consolidated financial statements.

	September 30, 2020			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 282	$ 64	$ 346
Derivative financial instruments liabilities	-	(330)	(20)	(350)

	December 31, 2019			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 193	$ 41	$ 234
Derivative financial instruments liabilities	-	(298)	-	(298)

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.

The Company has a fixed price contract to swap the market revenue of its Bloom Wind generation for a fixed annual payment for a 10-year term that expires in 2027. Commencing in 2019, forward market prices are available for the remaining period of this contract, however anticipated generation continues to be forecasted based on internal modelling. Accordingly, this financial instrument is classified as Level 3.

The Company has a 20-year revenue offtake swap agreement for Buckthorn Wind (see note 3), expiring in 2038, where the market price is swapped for a fixed price per unit of actual generation. The notional quantities are not set forth in the contract and observable forward market pricing is only available for the next 12 years. As such, the Company has developed a generation forecast for the remainder of the contract and a price forecast for the 6 years for which forward market prices are not available. These are both significant inputs to the determination of fair value, therefore this financial instrument is classified as Level 3.

In addition, as at September 30, 2020 and December 31, 2019, the Company holds contracts for the sale of renewable energy credits (RECs) for which pricing beyond two years is not readily observable and the contracts are therefore classified in Level 3 of the hierarchy.

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

	September 30, 2020	December 31, 2019
REC pricing (per certificate) – thermal	N/A	$1.05
REC pricing (per certificate) – solar	$216.40 to $422.41	$210.94 to $405.33
Power pricing (per MWh) – wind	$17.78 to $90.36	$16.88 to $49.14
Monthly generation (MWh) – Bloom Wind	54,426 to 72,000	54,426 to 72,000
Monthly generation (MWh) – Buckthorn Wind	11,365 to 21,736	N/A

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

10. Financial instruments, continued:

Fair value hierarchy, continued

Valuation process applied to Level 3

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

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

	September 30, 2020	December 31, 2019
REC pricing – thermal[2]	$ -	$ -
REC pricing – solar[2]	-	-
Power pricing – wind[2]	17	10
Generation – wind[3]	9	11

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

[3] Reflects the increase or decrease to fair value calculated using a 10% 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:

	September 30, 2020	December 31, 2019
As at January 1[4]	$ 41	$ (28)
Acquired from Buckthorn Wind (note 3)	44	-
Unrealized and realized (losses) gains included in net income (loss)[5]	(37)	69
Settlements[6]	(3)	-
Transfers[7]	(1)	-
As at end of period	$ 44	$ 41
Total unrealized and realized (losses) gains for the period included in net income (loss)[5]	$ (37)	$ 69

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

[5] Recorded in revenues.

[6] Relates to settlement of financial derivative instruments.

[7] Relates to transfers 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.

11. Risk management:

Risk management overview

During the first nine months of 2020, the COVID-19 pandemic has created a dynamic and challenging environment to navigate. Combined with a sharp decline in oil prices, the result has been notable market volatility, including fluctuations in interest rates, foreign currency rates and the Company's share price. The key implications of these developments on the Company's financial risk exposures and key strategies for mitigating those risks are addressed below.

The Company's risk management process, oversight and techniques are the same as those described in the Company's 2019 annual consolidated financial statements.

Market risk

Power price risk

Responses to the COVID-19 pandemic throughout North America have driven a reduction in demand for electricity as municipal, provincial and state authorities implemented social distancing policies, and stay-at-home and/or "shelter in place" directives. In turn, this put downward pressure on forward electricity prices for the balance of 2020 and for 2021. There is currently no certainty as to when the pandemic will be brought fully under control, but public expectations generally indicate that these impacts could continue to be felt into 2021. While it is possible that these impacts could extend further into 2021, a recovery in demand is already underway in Canada with both Alberta and Ontario progressing with opening up their economies. Both Alberta and Ontario continue to be supportive of keeping their economies open while addressing the recent increases in new cases.

Approximately half of Capital Power's net cash flows from operating activities come from facilities located outside of Alberta. These facilities are under long-term contractual arrangements with investment grade counterparties. As a result, these facilities have little exposure to the downward pressure on electricity prices as a result of lower electricity demand. The Company's thermal facility contracts typically are tolling arrangements in which most of the revenue is in the form of capacity payments that are paid regardless of the degree the plant is run. The Company's wind facilities receive fixed pricing for the power produced. In Ontario, where the lower electricity demand could result in some additional physical curtailment of wind facilities, Capital Power is held whole under the contractual arrangements even in the event of physical curtailment.

The balance of the Company's net cash flows from operating activities come from Alberta generation facilities. In 2020, approximately 60% of the Company's net cash flows from operating activities from Alberta facilities are under long-term contract with investment grade counterparties, including the tolling arrangement on the Shepard Energy Centre and the power purchase arrangements for Genesee 1 and 2 through the end of 2020. The balance of the output from the Company's Alberta facilities is sold into the Alberta merchant market, however, the Company continues to manage this exposure by entering into various purchase and sale arrangements for periods of varying duration. As at September 30, 2020, the Company's Alberta commercial baseload generation was substantially all sold forward for the remainder of 2020 which limits Capital Power's exposure to the recent drop in electricity demand.

Given that most of the Company's output is hedged in 2020, coupled with maintaining high facility availability, the Company has thus far not experienced significant impacts on its generation of net cash flows from operating activities related to recent developments.

11. Risk management, continued:

Market risk, continued

Power price risk, continued

For 2021, the portion of net cash flows from operating activities from Alberta facilities under long-term contracts is approximately 20%, and as at September 30, 2020, the balance of the Company's Alberta commercial baseload generation not under long-term contract was 13% sold forward for 2021. The relatively lower percentage sold forward for 2021 is driven by lower than normal liquidity and the gap between forward pricing and management's pricing expectations for 2021. The lower than normal liquidity and gap in price expectations are likely driven by uncertainty due to a number of factors including (i) impacts of the expiry of power purchase arrangements shifting more market share offer control from the Alberta Balancing Pool to commercial entities, (ii) continued impacts of COVID-19 and oil price reduction on demand, and (iii) carbon pricing. Despite the lower than typical percentage sold forward for the upcoming year, the Company continues to follow the same risk mitigation strategies as described in the Company's 2019 Management's Discussion and Analysis. In line with these risk mitigation strategies, the Company will be balancing the risks associated with being exposed to a higher volume of fluctuations in power prices with the risk of missing opportunities to sell power at higher expected prices in future periods.

During the second quarter of 2020, the Company updated its long-range forecasting and, given the prolonged nature of COVID-19 and oil pricing impacts, deemed the combined impact of the noted factors to be a triggering event to assess the Alberta cash-generating unit (CGU) for potential asset impairment. Impairment testing on the Alberta CGU was completed in the second quarter of 2020 with no impairment required.

Fuel supply and price risk

The reduction in oil prices in 2020 has driven a reduction in oil production which also impacts natural gas production tied to oil drilling. These reductions in natural gas supply have put upward pressure on natural gas prices for the balance of 2020 and beyond.

The Company's portfolio of generation comes from a variety of fuel types which minimizes exposure to any one fuel type. For natural gas, the Company uses long-term supply agreements including natural gas contracts as well as fixed transportation agreements to manage its exposure to increases in natural gas prices. As at September 30, 2020, the Company has economically hedged substantially all of its expected natural gas burn for the remainder of 2020 and 2021, and as a result does not anticipate significant fuel price risk in 2020 and 2021.

The fair value of the Company's energy related derivatives as at September 30, 2020, that are required to be measured at fair value with the respective changes in fair value recognized in net income (loss) are disclosed in note 7.

Foreign exchange risk

As a result of the current economic uncertainty created by the pandemic and the reduction in the price of oil, the Canadian dollar has weakened notably as compared to the U.S. dollar in the first quarter followed by a partial recovery during the second and third quarters of 2020. These fluctuations affect the Company's capital and operating costs, revenues and cash flows. and unfavourable fluctuations can adversely impact the Company's financial performance.

For the Company's facilities that have a U.S. functional currency, foreign exchange movements are largely matched within its U.S. operations and hence foreign exchange exposure is mitigated. The largest exposure the Company currently has to foreign exchange movements is related to capital costs for the Whitla Wind 2 and 3 project. The Company has entered into economic hedges on those capital costs during 2020 and 2021 to mitigate that exposure. At September 30, 2020, the Company held foreign exchange derivatives as disclosed in note 7.

11. Risk management, continued:

Credit risk

As a result of the economic impacts of both COVID-19 and the reduction in the price of oil, the risk that certain of the Company's counterparties will be unable to satisfy their contractual obligations has increased. Increased exposures include trade and other receivables on certain commercial and industrial customers as well as derivative financial instruments assets related to emissions portfolio trading.

The Company continues to actively monitor its exposure to counterparty credit risk and as at September 30, 2020, has recorded an allowance of less than $1 million for expected credit losses on trade and other receivables. Additionally, the Company has reflected increases in counterparty credit risk exposure within its fair value measurements of derivative financial instruments.

The Company continues to mitigate credit risk utilizing the risk mitigation practices described in the Company's 2019 annual consolidated financial statements including dealing largely with creditworthy counterparties. To further mitigate counterparty credit risk, the Company utilizes credit enhancements such as cash deposits, prepayments, parent company guarantees, bank letters of credit, master netting agreements, margin accounts and credit derivatives.

Liquidity risk

The potential for ongoing volatility in financial markets may create additional uncertainty when accessing capital. The Company's current liquidity remains strong and the Company was able to complete an offering of medium-term notes which closed on October 1, 2020 and covered the refinancing of medium-term notes that were to mature later in the year (see note 8). Additionally, the Company also continues to have available committed credit facilities to draw upon as described in the Company's Management's Discussion and Analysis for the nine months ended September 30, 2020. To date in 2020, the Company has not experienced and does not anticipate significant unfavourable impacts to liquidity driven by recent market developments.

12. Commitments:

Wind facility long-term service agreement extensions and Whitla Wind 2 and 3 turbine supply

In late April 2020, the Company signed agreements with Vestas setting the terms for 10-year long-term service agreement (LTSA) extensions for the maintenance of nine of the Company's wind facilities and the supply of turbines for the 97 MW of capacity of Whitla Wind 2 with commercial operations expected in 2021. The agreement for the supply of turbines for Whitla Wind 2 contained an option to supply turbines for Whitla Wind 3, which the Company exercised in the second quarter of 2020. The new LTSAs were executed in October 2020 and will take effect between 2021 and 2023.

Strathmore Solar project proceeding

On July 30, 2020, the Company announced that, subject to successful permitting and regulatory approvals, it is moving forward with the Strathmore Solar project, in Strathmore, Alberta, which will add 40.5 MW in early 2022. This will be the Company's first solar project in Canada and will have an expected capital cost in the range of $50 million to $55 million.

Whitla Wind 3 project proceeding

In June 2020, the Company announced that, subject to successful permitting and receipt of regulatory approvals, it is moving forward with the third phase of the Whitla Wind facility which will add 54 MW in late 2021. Capital Power will leverage its construction experience from Whitla Wind 1, to deliver Whitla Wind 3 with an expected capital cost of $92 million.

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

13. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation facilities within Canada (Alberta, British Columbia and Ontario) and in the U.S. (North Carolina, New Mexico, Kansas, Alabama, Arizona, North Dakota, Illinois and Texas), 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. and Canada.

The Company's results from operations and certain asset balances within each geographic area are:

	Three months ended September 30, 2020				Three months ended September 30, 2019			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues – external	$ 360	$ 61	$ -	$ 421	$ 350	$ 134	$ -	$ 484
Revenues – inter-area	(28)	(6)	34	-	-	4	(4)	-
Other income	12	20	-	32	19	14	-	33
Total revenues and other income	$ 344	$ 75	$ 34	$ 453	$ 369	$ 152	$ (4)	$ 517

	Nine months ended September 30, 2020				Nine months ended September 30, 2019			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues – external	$ 1,109	$ 213	$ -	$1,322	$ 819	$ 364	$ -	$1,183
Revenues – inter-area	(21)	(9)	30	-	20	10	(30)	-
Other income	37	62	-	99	52	45	-	97
Total revenues and other income	$ 1,125	$ 266	$ 30	$1,421	$ 891	$ 419	$ (30)	$1,280

	As at September 30, 2020			As at December 31, 2019		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 4,487	$ 1,768	$ 6,255	$ 4,555	$ 1,534	$ 6,089
Right-of-use assets	58	72	130	61	34	95
Intangible assets	605	146	751	615	145	760
Goodwill	35	-	35	35	-	35
Other assets	54	-	54	53	-	53
	$ 5,239	$ 1,986	$ 7,225	$ 5,319	$ 1,713	$ 7,032

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

	Three months ended September 30, 2020						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 133	$ 10	$ 81	$ 33	$ 257	$ 156	$ 413
Emission credit revenues	6	-	-	3	9	(1)	8
Total revenues[1]	$ 139	$ 10	$ 81	$ 36	$ 266	$ 155	$ 421

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

13. Segment information, continued:

	Nine months ended September 30, 2020						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 426	$ 30	$ 247	$ 140	$ 843	$ 458	$ 1,301
Emission credit revenues	20	-	-	7	27	(6)	21
Total revenues[1]	$ 446	$ 30	$ 247	$ 147	$ 870	$ 452	$ 1,322

[1] Included within trade and other receivables, as at September 30, 2020, were amounts related to contracts with customers of $112 million.

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

	Nine months ended September 30, 2019						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 461	$ 5	$ 162	$ 119	$ 747	$ 396	$ 1,143
Emission credit revenues	17	-	-	6	23	17	40
Total revenues[2]	$ 478	$ 5	$ 162	$ 125	$ 770	$ 413	$ 1,183

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

14. Subsequent event:

20-year contracts for three new solar development projects in North Carolina

In October 2020, the Company executed 20-year power purchase agreements with Duke Energy Carolinas for three solar development projects located in North Carolina totaling 160 MW. The solar projects consist of Hornet Solar (75 MW), Hunter's Cove Solar (50 MW), and Bear Branch Solar (35 MW) (collectively, the "solar projects"). Construction of the solar projects is expected to begin in late 2021 or early 2022 with commercial operations expected in the fourth quarter of 2022 and with expected capital costs of $118 million (US$90 million), $82 million (US$62 million) and $60 million (US$46 million) for the three projects, respectively.