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Capital Power
RESPONSIBLE ENERGY FOR TOMORROW

For immediate release | July 30, 2021

Capital Power reports strong second quarter results, increases its 2021 financial guidance, and announces a 6.8% common share dividend increase

EDMONTON, Alberta – July 30, 2021 – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended June 30, 2021.

Highlights

- Generated net cash flows from operating activities of $129 million and adjusted funds from operations (AFFO) of $91 million in the second quarter of 2021
- Generated net income of $17 million and adjusted EBITDA of $241 million in the second quarter of 2021
- Increased 2021 financial guidance for adjusted EBITDA to $1,090 million to $1,140 million (2021 target and original guidance of $975 million to $1,025 million) and AFFO to $570 million to $620 million (2021 target and original guidance of $500 million to $550 million)
- Completed successful offering of common shares for total gross proceeds of $288 million
- Executed a US$150 million private placement of 12-year senior notes
- Extended, amended and transitioned existing credit facilities into an inaugural $1 billion of Sustainability-linked credit facilities
- Increased the common share dividend by 6.8% to $2.19 per year representing the eighth consecutive annual increase

"Capital Power's financial results in the second quarter of 2021 exceeded management's expectations," said Brian Vaasjo, President and CEO of Capital Power. "Financial results benefitted from higher Alberta power prices where our trading desk captured an average realized power price of $75 per megawatt hour in the second quarter. This was partially offset by major outages at the Arlington Valley and Decatur Energy facilities, a stronger Canadian dollar relative to the U.S. dollar and lower wind resource availability at most of our wind facilities. Based on the strong forecast for the remainder of the year driven by a positive outlook for Alberta power prices, we have increased our 2021 financial guidance with revised guidance ranges now exceeding the top end of our original targets."

"I am pleased to announce that the Board of Directors has approved a 6.8% per common share dividend increase effective for the third quarter 2021 dividend payment, which is consistent with our 7% annual dividend growth guidance for 2021 and 5% for 2022," stated Mr. Vaasjo. "The annualized dividend of $2.19 per year is forecasted to be below our long-term AFFO payout ratio target of 45% to 55% in 2021."

"Debt and equity financing activities completed to date in 2021 were significant in reducing financing risk related to our growth initiatives, including 985 megawatts in advanced stages of development," said Sandra Haskins, SVP Finance and CFO of Capital Power. "With the completion of the $288 million common share offering we do not expect additional equity offerings will be required to fund our current growth projects. The successful financings and confidence in our long-term outlook are supported by the recent affirmations of our investment grade credit ratings and stable outlook by our credit rating agencies, S&P and DBRS."

Operational and Financial Highlights [1] (unaudited)	**Three months ended June 30**		**Six months ended June 30**	
(millions of dollars except per share and operational amounts)	**2021**	**2020**	**2021**	**2020**
Electricity generation (Gigawatt hours)	4,975	5,472	10,605	11,034
Generation facility availability	84%	92%	90%	92%
Revenues and other income [3]	$ 387	$ 435	$ 941	$ 968
Adjusted EBITDA [2, 3]	$ 241	$ 217	$ 544	$ 451
Net income [3]	$ 17	$ 23	$ 118	$ 23
Net income attributable to shareholders of the Company [3]	$ 20	$ 23	$ 123	$ 25
Basic earnings (loss) per share [3]	$ 0.05	$ 0.10	$ 0.88	$ (0.02)
Diluted earnings (loss) per share [3]	$ 0.05	$ 0.09	$ 0.87	$ (0.02)
Normalized earnings attributable to common shareholders [2,3]	$ 35	$ 18	$ 103	$ 46
Normalized earnings per share [2, 3]	$ 0.32	$ 0.17	$ 0.95	$ 0.44
Net cash flows from operating activities	$ 129	$ 91	$ 335	$ 194
Adjusted funds from operations [2]	$ 91	$ 97	$ 250	$ 215
Adjusted funds from operations per share [2]	$ 0.83	$ 0.92	$ 2.31	$ 2.04
Purchase of property, plant and equipment and other assets	$ 188	$ 87	$ 313	$ 186
Dividends per common share, declared	$ 0.5125	$ 0.4800	$ 1.0250	$ 0.9600

1 The operational and financial highlights in this press release should be read in conjunction with the Management's Discussion and Analysis and the unaudited condensed interim financial statements for the six months ended June 30, 2021.

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 June 30, 2021 and 2020 of $135 million and $121 million, respectively, and for the six months ended June 30, 2021 and 2020 of $270 million and $241 million (including $3 million related to the termination of East Windsor steam contract), respectively. Forecasted depreciation and amortization for the remainder of 2021 is $129 million for each of the third and fourth quarters, respectively.

Significant Events

Common share offering

In June of 2021 the Company completed a public offering of 7,480,750 common shares (inclusive of the full exercise of a 975,750 common shares over-allotment option), at an issue price of $38.45 per common share for total gross proceeds of $288 million (the Offering) less issue costs of $12 million. The Company intends to use the net proceeds from the Offering to fund growth initiatives (including projects in advanced stages of development) and for general corporate purposes.

Executive appointments

On April 30, 2021, Capital Power and the Board of Directors announced the following executive position appointments effective June 1, 2021:

- Bryan DeNeve, Senior Vice President Operations,
- Chris Kopecky, Senior Vice President and Chief Legal, Development and Commercial Officer, and
- Steve Owens, Senior Vice President Construction and Engineering.

Kate Chisholm, Sandra Haskins and Jacquie Pylypiuk will continue to serve in their current roles. Darcy Trufyn, Senior Vice President, Operations, Engineering and Construction retired from his role effective June 30, 2021. Darcy was an integral part of the executive team with outstanding service and valuable contributions over the past twelve years.

Executed 15-year contract for Enchant Solar project

On April 19, 2021, the Company announced that it executed a 15-year renewable energy agreement to sell 51% of the electricity generated from the 75 megawatt Enchant Solar project (Enchant Solar) in Alberta to Labatt Brewing Company Ltd. of Canada, along with bundled renewable energy certificates (RECs). Of the contracted capacity under this agreement, approximately one-quarter will be bundled with project-generated RECs directly from Enchant Solar and three-quarters will be packaged with RECs sourced from Eastern Canada. The terms of this agreement are consistent with the previously disclosed financial expectations for Enchant Solar.

Construction of Enchant Solar is set to commence in the second quarter of 2022 with commercial operations expected in the fourth quarter of 2022.

United States power operations relating to extreme weather event

During the February 9 to 20, 2021 period, extreme winter weather caused some disruptions to our wind facilities, most notably in Texas (Buckthorn Wind) with no significant impact on the balance of Capital Power's U.S. operations. Buckthorn Wind experienced no significant physical damage, but some turbines were forced offline. As of February 22, 2021, the operations were back to normal. The net impact of the U.S. storm on Buckthorn Wind resulted in increases of $8 million (US$6 million) to adjusted EBITDA and AFFO. In addition, during the peak days of the weather event, the Company was able to leverage its commodity management expertise to physically flow power around North America to contribute a further positive financial impact.

The favourable impacts of the weather event were largely driven by the settlement of the offtake and commodity swaps for Buckthorn Wind for the noted period of extreme weather. However, Buckthorn Wind's counterparty is contesting the settlement, arguing that settlement should have been based upon a different reference price. Historically these two prices have been similar, but as a result of the recent extreme weather, the Company became aware of a divergence in these prices during scarcity events. Both parties invoked dispute-resolution procedures during the first quarter of 2021 and the Company subsequently initiated litigation. Based on the contract terms of the offtake and commodity swaps, the Company considers the probability of ultimate settlement using the reference price advocated by the counterparty as being unlikely. In the event that the dispute is resolved unfavourably to the Company, the net exposure to the Company's revenues would be a reduction of up to approximately $18 million (US$15 million).

Approval of normal course issuer bid

During the first quarter of 2021, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 10.7 million of its outstanding common shares during the one-year period from February 26, 2021 to February 25, 2022.

<u>Subsequent Events</u>

Dividend increase

On July 29, 2021, the Company's Board of Directors approved an increase of 6.8% in the annual dividend for holders of its common shares, from $2.05 per common share to $2.19 per common share. This increased common share dividend will commence with the third quarter 2021 quarterly dividend payment on October 29, 2021 to shareholders of record at the close of business on September 30, 2021.

US$150 million private placement of senior notes

On July 20, 2021, the Company executed a US$150 million private placement of senior notes. The 12-year senior notes will bear a coupon rate of 3.24% and mature on October 28, 2033. Subject to satisfying closing conditions, the transaction is expected to fund on October 28, 2021. The net proceeds from the transaction will be used to fund growth initiatives including 985 megawatts (MW) in advanced stages of development and for general corporate purposes.

Sustainability-linked credit facilities

On July 14, 2021, the Company announced the extension, amendment and transition of its existing committed credit facilities to sustainability-linked credit facilities (SLCs). The 5-year commitment to SLCs extends the Company's existing $1 billion of unsecured credit facilities, which include a $700 million syndicated credit facility and an unsecured club credit facility of $300 million, to July 2026. The SLCs are structured with one key performance indicator with annual sustainability performance targets aligned to one of Capital Power's publicly stated sustainability targets: to reduce Scope 1 CO_2 emission intensity by 65% by 2030 from 2005 levels. The SLCs include terms that reduce or increase borrowing costs as the annual targets are met or missed.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on July 30, 2021 at 9:00 am (MT) to discuss the second quarter financial results. The conference call dial-in number is:

(800) 319-4610 (toll-free from Canada and USA)

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

Non-GAAP Financial Measures

The Company uses (i) 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							
	Jun 30 2021	**Mar 31 2021**	**Dec 30 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Revenues and other income	387	554	516	453	435	533	683	517
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(176)	(264)	(321)	(144)	(233)	(323)	(309)	(231)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	24	7	19	(31)	9	18	(28)	(8)
Adjusted EBITDA from joint venture [1]	6	6	6	6	6	6	6	6
Adjusted EBITDA	**241**	**303**	**220**	**284**	**217**	**234**	**352**	**284**
Depreciation and amortization	(135)	(135)	(122)	(115)	(121)	(120)	(118)	(135)
Unrealized changes in fair value of commodity derivatives and emission credits	(24)	(7)	(19)	31	(9)	(18)	28	8
Impairment reversal (losses)	2	-	(13)	-	-	(13)	-	(401)
Gains on acquisition and disposal transactions	-	-	-	-	-	-	24	-
Foreign exchange (loss) gain	(2)	1	5	1	3	(9)	-	(1)
Net finance expense	(46)	(41)	(57)	(47)	(49)	(44)	(41)	(42)
Finance expense and depreciation expense from joint venture [1]	(5)	-	(4)	(4)	(6)	(13)	(1)	(7)
Income tax (expense) recovery	(14)	(20)	(9)	(44)	(12)	(17)	(63)	66
Net income (loss)	**17**	**101**	**1**	**106**	**23**	**-**	**181**	**(228)**
Net income (loss) attributable to:								
Non-controlling interests	(3)	(2)	(2)	(2)	-	(2)	(1)	(2)
Shareholders of the Company	20	103	3	108	23	2	182	(226)
Net income (loss)	**17**	**101**	**1**	**106**	**23**	**-**	**181**	**(228)**

[1] Total income from joint venture as per the Company's consolidated statements of income.

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,

- 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, and
- include net expected cash outflows for the Company’s share of Line Loss Rule (LLR) Proceeding invoices in the period each tranche is paid by the Company.

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 June 30		Six months ended June 30	
	2021	**2020**	**2021**	**2020**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**129**	**91**	**335**	**194**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	20	34	61	62
Realized gains on settlement of interest rate derivatives	(12)	-	(12)	(1)
Change in fair value of derivatives reflected as cash settlement	7	8	11	18
Distributions received from joint venture	(2)	(3)	(5)	(5)
Miscellaneous financing charges paid [1]	2	1	3	3
Income taxes paid	-	7	5	33
Change in non-cash operating working capital	35	35	15	53
	50	82	78	163
Net finance expense [2]	(29)	(37)	(64)	(71)
Current income tax expense [3]	(13)	(10)	(16)	(16)
Sustaining capital expenditures [4]	(29)	(18)	(47)	(34)
Preferred share dividends paid	(13)	(13)	(26)	(26)
Remove tax equity interests’ respective shares of adjusted funds from operations	(2)	(2)	(6)	(4)
Adjusted funds from operations from joint venture	5	4	9	9
Line Loss Rule Proceeding [5]	(7)	-	(13)	-
Adjusted funds from operations	**91**	**97**	**250**	**215**
Weighted average number of common shares outstanding (millions)	**109.7**	**105.1**	**108.3**	**105.2**
Adjusted funds from operations per share ($)	**0.83**	**0.92**	**2.31**	**2.04**

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 For the three and six months ended June 30, 2021, excludes current income tax expenses of $8 million related to the Genesee 3 and Keephills 3 swap transaction, as these amounts are considered investing activities (three and six months ended June 30, 2020 excludes current income tax recoveries of nil and $20 million, respectively).

4 Includes sustaining capital expenditures net of partner contributions of $2 million and $7 million for the three and six months ended June 30, 2021, respectively, compared with $2 million and $3 million for the three and six months ended June 30, 2020, respectively.

5 The LLR Proceeding invoicing process has resulted in gross billings to Capital Power of which amounts not attributable to Capital Power have been partly recovered from the appropriate parties for their respective shares. For the three and six months ended June 30, 2021, actual net cash outflows of $22 million and $35 million, respectively, for the LLR Proceeding amounts are reflected in net cash flows from operating activities through the change in non-cash operating working capital, which is removed in the calculation of AFFO. AFFO for the three and six months ended June 30, 2021, is impacted only by the Company’s obligation related to the 2006-2009 and 2010-2013 invoice tranches ($7 million and $13 million for the three and six months ended June 30, 2021, respectively) consistent with the Company’s definition of AFFO described above. The AFFO impacts differ from the actual cash outflows by the amounts paid by the Company but expected to be recovered from other parties (see Contingent Liabilities and Provisions).

Normalized earnings attributable to common shareholders and normalized earnings per share

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

(unaudited, $ millions except per share amounts and number of common shares)	Three months ended							
	Jun 30 2021	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Basic earnings (loss) per share ($)	**0.05**	**0.83**	**(0.09)**	**0.89**	**0.10**	**(0.11)**	**1.61**	**(2.25)**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)	**20**	**103**	**3**	**108**	**23**	**2**	**182**	**(226)**
Preferred share dividends including Part VI.1 tax	(14)	(14)	(13)	(14)	(13)	(14)	(12)	(14)
Earnings (loss) attributable to common shareholders	6	89	(10)	94	10	(12)	170	(240)
Unrealized changes in fair value of derivatives [1]	25	(10)	12	(28)	3	30	(28)	(3)
Provision for contingency	6	-	-	-	-	-	-	-
Impairment (reversal) losses	(2)	-	10	-	-	10	-	-
Reduction in applicable jurisdictional tax rates	-	(10)	-	-	-	-	-	-
Provision for Line Loss Rule Proceeding [2]	-	(1)	1	-	3	-	4	-
Restructuring charges	-	-	-	2	-	-	-	-
Other tax adjustment	-	-	-	1	-	-	-	-
Termination of East Windsor steam contract	-	-	-	-	2	-	-	-
Net (gain) loss on swap transaction	-	-	-	-	-	-	(115)	307
Alberta tax rate change	-	-	-	-	-	-	-	-
Normalized earnings attributable to common shareholders	**35**	**68**	**13**	**69**	**18**	**28**	**31**	**64**
Weighted average number of common shares outstanding (millions)	109.7	106.8	105.7	105.1	105.1	105.4	105.3	106.5
Normalized earnings per share ($)	**0.32**	**0.64**	**0.12**	**0.66**	**0.17**	**0.27**	**0.29**	**0.60**

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

2 See Contingent Liabilities and Provisions.

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, and updates to, the Company's 2021 AFFO and adjusted EBITDA guidance, (ii) forecasted depreciation for the remainder of 2021, (iii) the intended use of proceeds from the common share offering (see Significant Events), (iv) expectations pertaining to the financial guidance, timing of construction and timing of commercial operations commencement of Enchant Solar (see Significant Events), (v) expectations around the resolution of the pricing dispute on the Buckthorn Wind offtake and commodity swaps (see Significant Events), (vi) the intended use of proceeds and expected closing date of the U.S. private placement of senior notes (see Subsequent Events) and (vii) matters relating to the LLR Proceeding, including the recovery from appropriate parties.

These statements are based on certain assumptions and analyses made by the Company considering 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) performance, (iii) business prospects (including the need for and potential re-contracting of facilities) and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates, and (vi) matters relating to the LLR Proceeding, including the recovery and timing thereof from appropriate parties.

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, natural gas and carbon prices in markets in which the Company operates and the use of derivatives, (ii) regulatory and political environments including changes to environmental, climate, financial reporting, market structure and tax legislation, (iii) generation facility availability, wind capacity factor and performance including maintenance expenditures, (iv) ability to fund current and future capital and working capital needs, (v) acquisitions and developments including timing and costs of regulatory approvals and construction, (vi) changes in the availability of fuel, (vii) ability to realize the anticipated benefits of acquisitions, (viii) limitations inherent in the Company's review of acquired assets, (ix) changes in general economic and competitive conditions and (x) changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs. See Risks and Risk Management in the Company's Management's Discussion and Analysis for both the six months ended June 30, 2021, prepared as of July 29, 2021 and the Company's Integrated Annual Report for the year ended December 31, 2020, prepared as of February 18, 2021, 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 wholesale power producer with a strategic focus on sustainable energy headquartered in Edmonton, Alberta. We build, own, and operate high-quality, utility-scale generation facilities that include renewables and thermal. We have also made significant investments in carbon capture and utilization to reduce carbon impacts and are committed to be off coal in 2023. Capital Power owns over 6,400 MW of power generation capacity at 26 facilities across North America. Projects in advanced development include 425 MW of owned renewable generation capacity in North Carolina and Alberta and 560 MW of incremental natural gas combined cycle capacity from the repowering of Genesee 1 and 2 in Alberta.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A), prepared as of July 29, 2021, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the six months ended June 30, 2021, the audited consolidated financial statements and Company Overview, Our Strategy and Business Report sections of the Integrated Annual Report of Capital Power Corporation for the year ended December 31, 2020 (the 2020 Integrated Annual Report), the Annual Information Form of Capital Power Corporation dated February 23, 2021, and the cautionary statements regarding forward-looking information which begin on page 10.

In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation together with its subsidiaries.

In this MD&A, financial information for the six months ended June 30, 2021 and the six months ended June 30, 2020 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods which were prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors approved this MD&A as of July 29, 2021.

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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:

- our 2021 performance targets and current period updates to our expectations, including for facility availability, sustaining capital expenditures, adjusted funds from operations (AFFO) and adjusted EBITDA;
- our company-wide targets specific to climate-related performance, including reduction of emissions and emissions intensity, repowering of Genesee 1 and Genesee 2, completion of the Genesee Carbon Conversion Centre, commercial application of carbon conversion technologies and plans to be off coal in 2023;
- future revenues, expenses, earnings, adjusted EBITDA and AFFO;
- 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 and dividends;
- the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings;
- the timing and costs for development projects (including the repowering of Genesee 1 and 2, phases 2 and 3 of Whitla Wind, Strathmore Solar, Bear Branch Solar, Hornet Solar, Hunter's Cove Solar and Enchant Solar);
- facility availability and planned outages;
- capital expenditures for facility maintenance and other (sustaining capital, future growth projects, commercial initiatives);
- the impact of market designs on the Company's core markets;
- matters related to the LLR Proceeding including recovery from appropriate parties and potential impacts to the Company arising from the foregoing;
- the costs of exiting the series of agreements previously entered into pertaining to the Genesee 4 and 5 project;
- the resolution of the pricing dispute on the Buckthorn Wind offtake and commodity swaps (see Significant Events);
- the intended use of proceeds of the common share offering (see Significant Events);
- the intended use of proceeds and expected closing date of the U.S. private placement of senior notes (see Subsequent Events); and
- the impact of the COVID-19 pandemic.

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, other energy, and carbon prices;
- performance;
- business prospects (including the need for and 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;
- the development and performance of technology;
- foreign exchange rates;
- matters relating to the LLR Proceeding, including the recovery and timing thereof 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, natural gas and carbon prices in markets in which the Company operates and the use of derivatives;
- regulatory and political environments including changes to environmental, climate, financial reporting, market structure 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 the availability of fuel;
- ability to realize the anticipated benefits of acquisitions;
- limitations inherent in the Company's review of acquired assets;
- changes in general economic and competitive conditions;
- changes in the performance and cost of technologies and the development of new technologies, new energy efficient products, services and programs; and
- risks and uncertainties discussed under the Risks and Risk Management section.

See Risks and Risk Management in the Company's 2020 Integrated Annual Report 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 date made. 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 wholesale power producer with a strategic focus on sustainable energy headquartered in Edmonton, Alberta. We build, own, and operate high-quality, utility-scale generation facilities that include renewables and thermal. We have also made significant investments in carbon capture and utilization to reduce carbon impacts and are committed to be off coal in 2023. Capital Power owns over 6,400 megawatts (MW) of power generation capacity at 26 facilities across North America. Projects in advanced development include 425 MW of owned renewable generation capacity in North Carolina and Alberta and 560 MW of incremental natural gas combined cycle capacity from the repowering of Genesee 1 and 2 in Alberta.

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 2020 Integrated Annual Report.

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	2021 target	Actual results for the six months ended June 30, 2021
Facility availability average	93% or greater	90%
Sustaining capital expenditures	$80 to $90 million	$47 million [1]

[1] Includes sustaining capital expenditures net of joint venture contributions of $7 million.

The Company's facility availability averaged 90% which reflected planned outages at Arlington Valley, Shepard, Goreway and Decatur Energy. Unplanned outages also occurred at Island Generation and Genesee.

Sustaining capital expenditures for the six months ended June 30, 2021 were lower than target for the year to date primarily due to various budgeted sustaining capital projects for which spending will occur later in the year. Full year sustaining capital expenditures are expected to be consistent with the target range.

Disciplined growth

Performance measure	2021 target	Status as at June 30, 2021
Repowering of Genesee 1 and 2	Pending regulatory approval, expect construction to begin in the third quarter of 2021, with an anticipated in-service date in late 2023 for the repowered Genesee 1 and 2024 for Genesee 2.	All regulatory approvals have been received and construction is expected to begin in the third quarter of 2021. The anticipated in-service dates remain consistent with target.
Renewable projects:	Target completion dates on time and on budget for 2021 projects and progress on the development of 2022 projects to be on track with budget and completion dates.	The renewable projects below remain on budget and are on track with their targeted in-service dates.
Whitla Wind 2 (Alberta)	Fourth quarter of 2021	
Whitla Wind 3 (Alberta)	Fourth quarter of 2021	
Strathmore Solar (Alberta)	Early 2022	
Enchant Solar (Alberta)	Fourth quarter of 2022	
Hornet Solar (North Carolina)	Fourth quarter of 2022	
Hunter's Cove Solar (North Carolina)	Fourth quarter of 2022	
Bear Branch Solar (North Carolina)	Fourth quarter of 2022	
Other growth	$500 million of committed capital	The Company continues to explore growth opportunities and expects to be able to achieve this target during the year.

Financial stability and strength

Performance measure	2021 target	2021 updated guidance [3]	Actual results to June 30, 2021
Adjusted funds from operations [1]	$500 million to $550 million [2]	$570 million to $620 million	$250 million
Adjusted EBITDA [1]	$975 million to $1,025 million	$1,090 million to $1,140 million	$544 million

1 AFFO and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures.

2 Target excludes impact from the Line Loss Rule (LLR) Proceeding. Actual results for the six months ended June 30, 2021, as well as the 2021 updated guidance, reflect a cash outflow of $13 million related to the LLR Proceeding.

3 Based on the Company's year-to-date results and expectations for the remainder of the year, the Company has provided updated guidance for 2021 (see Outlook).

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 2020, the Company provided financial guidance for 2021 AFFO in the range of $500 million to $550 million and 2021 adjusted EBITDA in the range of $975 million to $1,025 million (see Non-GAAP Financial Measures). Based on the actual results for the first half of 2021 and the Company's forecast for the back half of the year, the Company now expects AFFO and adjusted EBITDA for 2021 to be in the range of $570 million to $620 million for AFFO and $1,090 million to $1,140 million for adjusted EBITDA. The increased guidance ranges are driven most notably by the strength of the Alberta power market, inclusive of actual performance in the first half of 2021 and expectations for the back half of 2021. The updated guidance ranges consider the Company's existing Alberta portfolio position for the remainder of the year as well as strong forward pricing for our remaining Alberta generation. Additionally, the estimated impacts of the Genesee 2 outage that occurred subsequent to the close of the second quarter are included in the updated guidance ranges.

Priorities for the Company in 2021 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 advancement of the repowering of Genesee 1 and 2 and ongoing development of our wind and solar projects.

In 2021, Capital Power's availability target of 93% reflects major scheduled maintenance outages for Genesee 2, Decatur Energy and Shepard compared to those scheduled for Genesee 2 (subsequently deferred to 2021), Arlington Valley, Decatur Energy and Southport in 2020.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2022, 2023 and 2024 (all as at June 30, 2021) were:

Alberta commercial portfolio positions and power prices	Full year 2022	Full year 2023	Full year 2024
Percentage of baseload generation sold forward [1]	42%	30%	15%
Contracted price [2]	High-$50	Mid-$50	Mid-$50
Forward Alberta pool prices	$68	$57	$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 2021 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 2020, the Company confirmed its annual dividend growth guidance for 2021 and 2022 at 7% and 5%, respectively. 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. The Company significantly reduced financing risk for its current growth initiatives, including 985 MW in advanced stages of development, with the financing activities completed to date in 2021 (see Significant Events and Subsequent Events). Outside of new growth opportunities the Company does not expect additional equity offerings will be required to fund growth.

NON-GAAP FINANCIAL MEASURES

The Company uses (i) earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from its joint venture interests, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emission credits (adjusted EBITDA), (ii) 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							
	Jun 30 2021	**Mar 31 2021**	**Dec 30 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Revenues and other income	387	554	516	453	435	533	683	517
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(176)	(264)	(321)	(144)	(233)	(323)	(309)	(231)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	24	7	19	(31)	9	18	(28)	(8)
Adjusted EBITDA from joint venture [1]	6	6	6	6	6	6	6	6
Adjusted EBITDA	**241**	**303**	**220**	**284**	**217**	**234**	**352**	**284**
Depreciation and amortization	(135)	(135)	(122)	(115)	(121)	(120)	(118)	(135)
Unrealized changes in fair value of commodity derivatives and emission credits	(24)	(7)	(19)	31	(9)	(18)	28	8
Impairment reversal (losses)	2	-	(13)	-	-	(13)	-	(401)
Gains on acquisition and disposal transactions	-	-	-	-	-	-	24	-
Foreign exchange (loss) gain	(2)	1	5	1	3	(9)	-	(1)
Net finance expense	(46)	(41)	(57)	(47)	(49)	(44)	(41)	(42)
Finance expense and depreciation expense from joint venture [1]	(5)	-	(4)	(4)	(6)	(13)	(1)	(7)
Income tax (expense) recovery	(14)	(20)	(9)	(44)	(12)	(17)	(63)	66
Net income (loss)	**17**	**101**	**1**	**106**	**23**	**-**	**181**	**(228)**
Net income (loss) attributable to:								
Non-controlling interests	(3)	(2)	(2)	(2)	-	(2)	(1)	(2)
Shareholders of the Company	20	103	3	108	23	2	182	(226)
Net income (loss)	**17**	**101**	**1**	**106**	**23**	**-**	**181**	**(228)**

[1] Total income from joint venture as per the Company's consolidated statements of income.

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,
- 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, and
- include net expected cash outflows for the Company's share of Line Loss Rule (LLR) Proceeding invoices in the period each tranche is paid by the Company.

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 June 30**		**Six months ended June 30**	
	2021	**2020**	**2021**	**2020**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**129**	**91**	**335**	**194**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	20	34	61	62
Realized gains on settlement of interest rate derivatives	(12)	-	(12)	(1)
Change in fair value of derivatives reflected as cash settlement	7	8	11	18
Distributions received from joint venture	(2)	(3)	(5)	(5)
Miscellaneous financing charges paid [1]	2	1	3	3
Income taxes paid	-	7	5	33
Change in non-cash operating working capital	35	35	15	53
	50	82	78	163
Net finance expense [2]	(29)	(37)	(64)	(71)
Current income tax expense [3]	(13)	(10)	(16)	(16)
Sustaining capital expenditures [4]	(29)	(18)	(47)	(34)
Preferred share dividends paid	(13)	(13)	(26)	(26)
Remove tax equity interests' respective shares of adjusted funds from operations	(2)	(2)	(6)	(4)
Adjusted funds from operations from joint venture	5	4	9	9
Line Loss Rule Proceeding [5]	(7)	-	(13)	-
Adjusted funds from operations	**91**	**97**	**250**	**215**
Weighted average number of common shares outstanding (millions)	**109.7**	**105.1**	**108.3**	**105.2**
Adjusted funds from operations per share ($)	**0.83**	**0.92**	**2.31**	**2.04**

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 For the three and six months ended June 30, 2021, excludes current income tax expenses of $8 million related to the Genesee 3 and Keephills 3 swap transaction as these amounts are considered investing activities (three and six months ended June 30, 2020 excludes current income tax recoveries of nil and $20 million, respectively).

4 Includes sustaining capital expenditures net of partner contributions of $2 million and $7 million for the three and six months ended June 30, 2021, respectively, compared with $2 million and $3 million for the three and six months ended June 30, 2020, respectively.

5 The LLR Proceeding invoicing process has resulted in gross billings to Capital Power of which amounts not attributable to Capital Power have been partly recovered from the appropriate parties for their respective shares. For the three and six months ended June 30, 2021, actual net cash outflows of $22 million and $35 million, respectively, for the LLR Proceeding amounts are reflected in net cash flows from operating activities through the change in non-cash operating working capital, which is removed in the calculation of AFFO. AFFO for the three and six months ended June 30, 2021, is impacted only by the Company's obligation related to the 2006-2009 and 2010-2013 invoice tranches ($7 million and $13 million for the three and six months ended June 30, 2021, respectively) consistent with the Company's definition of AFFO described above. The AFFO impacts differ from the actual cash outflows by the amounts paid by the Company but expected to be recovered from other parties (see Contingent Liabilities and Provisions).

Normalized earnings attributable to common shareholders and normalized earnings per share

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

(unaudited, $ millions except per share amounts and number of common shares)	Three months ended							
	Jun 30 2021	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Basic earnings (loss) per share ($)	**0.05**	**0.83**	**(0.09)**	**0.89**	**0.10**	**(0.11)**	**1.61**	**(2.25)**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)	**20**	**103**	**3**	**108**	**23**	**2**	**182**	**(226)**
Preferred share dividends including Part VI.1 tax	(14)	(14)	(13)	(14)	(13)	(14)	(12)	(14)
Earnings (loss) attributable to common shareholders	6	89	(10)	94	10	(12)	170	(240)
Unrealized changes in fair value of derivatives [1]	25	(10)	12	(28)	3	30	(28)	(3)
Provision for contingency	6	-	-	-	-	-	-	-
Impairment (reversal) losses	(2)	-	10	-	-	10	-	-
Reduction in applicable jurisdictional tax rates	-	(10)	-	-	-	-	-	-
Provision for Line Loss Rule Proceeding [2]	-	(1)	1	-	3	-	4	-
Restructuring charges	-	-	-	2	-	-	-	-
Other tax adjustment	-	-	-	1	-	-	-	-
Termination of East Windsor steam contract	-	-	-	-	2	-	-	-
Net (gain) loss on swap transaction	-	-	-	-	-	-	(115)	307
Alberta tax rate change	-	-	-	-	-	-	-	-
Normalized earnings attributable to common shareholders	**35**	**68**	**13**	**69**	**18**	**28**	**31**	**64**
Weighted average number of common shares outstanding (millions)	109.7	106.8	105.7	105.1	105.1	105.4	105.3	106.5
Normalized earnings per share ($)	**0.32**	**0.64**	**0.12**	**0.66**	**0.17**	**0.27**	**0.29**	**0.60**

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

2 See Contingent Liabilities and Provisions.

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Three months ended June 30		Six months ended June 30	
	2021	**2020**	**2021**	**2020**
Revenues and other income	387	435	941	968
Adjusted EBITDA [1]	241	217	544	451
Net income	17	23	118	23
Net income attributable to shareholders of the Company	20	23	123	25
Normalized earnings attributable to common shareholders [1]	35	18	103	46
Basic earnings (loss) per share ($)	0.05	0.10	0.88	(0.02)
Diluted earnings (loss) per share ($) [2]	0.05	0.09	0.87	(0.02)
Normalized earnings per share ($) [1]	0.32	0.17	0.95	0.44
Net cash flows from operating activities	129	91	335	194
Adjusted funds from operations [1]	91	97	250	215
Adjusted funds from operations per share ($) [1]	0.83	0.92	2.31	2.04
Purchase of property, plant and equipment and other assets	188	87	313	186
Dividends per common share, declared ($)	0.5125	0.4800	1.0250	0.9600
Dividends per Series 1 preferred share, declared ($)	0.1638	0.1913	0.3276	0.3825
Dividends per Series 3 preferred share, declared ($)	0.3408	0.3408	0.6816	0.6816
Dividends per Series 5 preferred share, declared ($)	0.3274	0.3274	0.6548	0.6548
Dividends per Series 7 preferred share, declared ($)	0.3750	0.3750	0.7500	0.7500
Dividends per Series 9 preferred share, declared ($)	0.3594	0.3594	0.7188	0.7188
Dividends per Series 11 preferred share, declared ($)	0.3594	0.3594	0.7188	0.7188

	As at	
	June 30, 2021	**December 31, 2020**
Loans and borrowings including current portion	2,983	3,552
Total assets	8,608	8,911

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

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

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 income (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 June 30, 2021 was lower than the corresponding period in 2020 mainly due to lower AFFO from our U.S. and Ontario contracted facilities driven by the factors described in Consolidated Net Income and Results of Operations, higher sustaining capital expenditures, the AFFO impact of the third tranche of LLR Proceeding invoices paid during the quarter and higher current income tax expenses impacting AFFO. These factors were partially offset by higher AFFO from our Alberta Commercial facilities mainly due to higher realized power pricing and lower net finance expense in 2021. AFFO for the six months ended June 30, 2021 was higher than the corresponding period in 2020 primarily due to higher AFFO from our Alberta Commercial facilities, mainly due to higher realized power pricing, and lower net finance expense in 2021. These increases were partially offset by lower AFFO from our U.S. and Ontario contracted facilities driven by the factors described in Consolidated Net Income and Results of Operations, the AFFO impact of the second and third tranches of LLR Proceeding invoices paid during the period and higher sustaining capital expenditures in 2021.

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

SIGNIFICANT EVENTS

Common share offering

In June of 2021 the Company completed a public offering of 7,480,750 common shares (inclusive of the full exercise of a 975,750 common shares over-allotment option), at an issue price of $38.45 per common share for total gross proceeds of approximately $288 million (the Offering) less issue costs of $12 million. The Company intends to use the net proceeds from the Offering to fund growth initiatives (including projects in advanced stages of development) and for general corporate purposes.

Executive appointments

On April 30, 2021, Capital Power and the Board of Directors announced the following executive position appointments effective June 1, 2021:

- Bryan DeNeve, Senior Vice President Operations,
- Chris Kopecky, Senior Vice President and Chief Legal, Development and Commercial Officer, and
- Steve Owens, Senior Vice President Construction and Engineering.

Kate Chisholm, Sandra Haskins and Jacquie Pylypiuk will continue to serve in their current roles. Darcy Trufyn, Senior Vice President, Operations, Engineering and Construction retired from his role effective June 30, 2021. Darcy was an integral part of the executive team with outstanding service and valuable contributions over the past twelve years.

Executed 15-year contract for Enchant Solar project

On April 19, 2021, the Company announced that it executed a 15-year renewable energy agreement to sell 51% of the electricity generated from the 75 megawatt Enchant Solar project (Enchant Solar) in Alberta to Labatt Brewing Company Ltd. of Canada, along with bundled renewable energy certificates (RECs). Of the contracted capacity under this agreement, approximately one-quarter will be bundled with project-generated RECs directly from Enchant Solar and three-quarters will be packaged with RECs sourced from Eastern Canada. The terms of this agreement are consistent with the previously disclosed financial expectations for Enchant Solar.

Construction of Enchant Solar is set to commence in the second quarter of 2022 with commercial operations expected in the fourth quarter of 2022.

United States power operations relating to extreme weather event

During the February 9 to 20, 2021 period, extreme winter weather caused some disruptions to our wind facilities, most notably in Texas (Buckthorn Wind) with no significant impact on the balance of Capital Power's U.S. operations. Buckthorn Wind experienced no significant physical damage, but some turbines were forced offline. As of February 22, 2021, the operations were back to normal. The net impact of the U.S. storm on Buckthorn Wind resulted in increases of $8 million (US$6 million) to adjusted EBITDA and AFFO. In addition, during the peak days of the weather event, the Company was able to leverage its commodity management expertise to physically flow power around North America to contribute a further positive financial impact.

The favourable impacts of the weather event were largely driven by the settlement of the offtake and commodity swaps for Buckthorn Wind for the noted period of extreme weather. However, Buckthorn Wind's counterparty is contesting the settlement, arguing that settlement should have been based upon a different reference price. Historically these two prices have been similar, but as a result of the recent extreme weather, the Company became aware of a divergence in these prices during scarcity events. Both parties invoked dispute-resolution procedures during the first quarter of 2021 and the Company subsequently initiated litigation. Based on the contract terms of the offtake and commodity swaps, the Company considers the probability of ultimate settlement using the reference price advocated by the counterparty as being unlikely. In the event that the dispute is resolved unfavourably to the Company, the net exposure to the Company's revenues would be a reduction of up to approximately $18 million (US$15 million).

Approval of normal course issuer bid

During the first quarter of 2021, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 10.7 million of its outstanding common shares during the one-year period from February 26, 2021 to February 25, 2022.

SUBSEQUENT EVENTS

Dividend increase

On July 29, 2021, the Company's Board of Directors approved an increase of 6.8% in the annual dividend for holders of its common shares, from $2.05 per common share to $2.19 per common share. This increased common share dividend will commence with the third quarter 2021 quarterly dividend payment on October 29, 2021 to shareholders of record at the close of business on September 30, 2021.

US$150 million private placement of senior notes

On July 20, 2021, the Company executed a US$150 million private placement of senior notes. The 12-year senior notes will bear a coupon rate of 3.24% and mature on October 28, 2033. Subject to satisfying closing conditions, the transaction is expected to fund on October 28, 2021. The net proceeds from the transaction will be used to fund growth initiatives including 985 MW in advanced stages of development and for general corporate purposes.

Sustainability-linked credit facilities

On July 14, 2021, the Company announced the extension, amendment and transition of its existing committed credit facilities to sustainability-linked credit facilities (SLCs). The 5-year commitment to SLCs extends the Company's existing $1 billion of unsecured credit facilities, which include a $700 million syndicated credit facility and an unsecured club credit facility of $300 million, to July 2026. The SLCs are structured with one key performance indicator with annual sustainability performance targets aligned to one of Capital Power's publicly stated sustainability targets: to reduce Scope 1 CO_2 emission intensity by 65% by 2030 from 2005 levels. The SLCs include terms that reduce or increase borrowing costs as the annual targets are met or missed.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for the three and six months ended June 30, 2021 compared with 2020 are presented below followed by further discussion of these items.

(unaudited, $ millions)	Three months		Six months	
Consolidated net income for the periods ended June 30, 2020		**23**		**23**
Increase (decrease) in adjusted EBITDA:				
Alberta commercial facilities and portfolio optimization	30		63	
Western Canada contracted facilities	(3)		(4)	
Ontario contracted facilities	(7)		(8)	
U.S. contracted facilities	(21)		3	
Corporate	25	24	39	93
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		(15)		(4)
Increase in depreciation and amortization expense		(14)		(29)
Decrease in impairments		2		15
Change in foreign exchange gain (loss)		(5)		5
Decrease in finance expense and depreciation expense from joint venture		1		14
Decrease in net finance expense		3		6
Increase (decrease) in income before tax		(4)		100
Increase in income tax expense		(2)		(5)
Increase (decrease) in net income		**(6)**		**95**
Consolidated net income for the periods ended June 30, 2021		**17**		**118**

Results by facility category and other

	Three months ended June 30							
	2021	2020	2021	2020	2021	2020	2021	2020
	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	4,975	5,472	84	92	528	353		
Alberta commercial facilities [4]								
Genesee 1	708	689	92	100	78	32		
Genesee 2	701	618	100	97	80	29		
Genesee 3	951	926	95	95	100	28		
Clover Bar Energy Centre 1, 2 and 3	67	79	94	90	14	3		
Joffre	180	132	95	100	27	10		
Shepard	379	770	50	99	38	27		
Halkirk Wind	111	121	98	99	14	10		
Clover Bar Landfill Gas	-	1	-	48	-	-		
Alberta commercial facilities	3,097	3,336	87	97	351	139		
Portfolio optimization	N/A	N/A	N/A	N/A	(37)	102		
	3,097	3,336	87	97	314	241	136	106
Western Canada contracted facilities [4,5]								
Island Generation	114	-	89	100	8	9		
Quality Wind	83	99	98	98	9	9		
EnPower	7	3	93	74	-	-		
Whitla Wind 1	178	192	98	97	8	9		
	382	294	94	98	25	27	18	21
Ontario contracted facilities [5]								
York Energy [6]	5	3	100	100	N/A	N/A		
East Windsor	4	2	100	96	7	8		
Goreway	159	217	89	96	47	51		
Kingsbridge 1	20	21	98	98	2	1		
Port Dover and Nanticoke Wind	66	70	99	99	10	10		
	254	313	93	97	66	70	49	56
U.S. contracted facilities								
Roxboro, North Carolina [7]	N/A	84	N/A	99	N/A	10		
Southport, North Carolina [7]	N/A	114	N/A	100	N/A	18		
Decatur Energy, Alabama	240	327	51	73	12	15		
Arlington Valley, Arizona	461	404	78	77	35	28		
Beaufort Solar, North Carolina	8	8	97	100	1	1		
Bloom Wind, Kansas	177	212	98	98	9	12		
Macho Springs Wind, New Mexico	41	43	98	98	5	5		
New Frontier Wind, North Dakota	93	102	97	98	5	9		
Cardinal Point Wind, Illinois [8]	141	138	97	95	14	12		
Buckthorn Wind, Texas [9]	81	97	94	95	5	7		
	1,242	1,529	72	82	86	117	35	56
Corporate [10]					32	12	3	(22)
Unrealized changes in fair value of commodity derivatives and emission credits					(136)	(32)		
Consolidated revenues and other income and adjusted EBITDA					**387**	**435**	**241**	**217**

	Six months ended June 30							
	2021	2020	2021	2020	2021	2020	2021	2020
	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	10,605	11,034	90	92	1,081	796		
Alberta commercial facilities [4]								
Genesee 1	1,324	1,481	92	98	141	68		
Genesee 2	1,282	1,391	100	97	141	62		
Genesee 3	1,855	1,839	95	93	188	91		
Clover Bar Energy Centre 1, 2 and 3	90	275	97	93	22	25		
Joffre	383	318	98	96	53	29		
Shepard	1,182	1,637	75	100	91	72		
Halkirk Wind	262	269	98	99	33	24		
Clover Bar Landfill Gas	-	2	-	50	-	-		
Alberta commercial facilities	6,378	7,212	92	97	669	371		
Portfolio optimization	N/A	N/A	N/A	N/A	(12)	146		
	6,378	7,212	92	97	657	517	301	238
Western Canada contracted facilities [4,5]								
Island Generation	142	7	94	100	18	19		
Quality Wind	210	221	98	97	25	25		
EnPower	18	13	91	80	1	1		
Whitla Wind 1	413	430	98	97	18	19		
	783	671	96	98	62	64	47	51
Ontario contracted facilities [5]								
York Energy [6]	9	7	100	100	N/A	N/A		
East Windsor	4	3	99	98	15	16		
Goreway	393	360	94	92	105	100		
Kingsbridge 1	50	53	99	99	4	4		
Port Dover and Nanticoke Wind	147	160	99	99	22	23		
	603	583	96	94	146	143	106	114
U.S. contracted facilities								
Roxboro, North Carolina [7]	57	165	100	95	7	20		
Southport, North Carolina [7]	60	219	100	93	11	34		
Decatur Energy, Alabama	596	451	65	80	36	36		
Arlington Valley, Arizona	1,006	781	89	71	59	54		
Beaufort Solar, North Carolina	14	14	98	100	1	1		
Bloom Wind, Kansas	342	395	96	98	18	23		
Macho Springs Wind, New Mexico	79	78	98	98	9	9		
New Frontier Wind, North Dakota	196	212	95	98	11	17		
Cardinal Point Wind, Illinois [8]	311	156	98	94	30	17		
Buckthorn Wind, Texas [9]	180	97	94	95	22	7		
	2,841	2,568	81	82	204	218	90	87
Corporate [10]					62	23	-	(39)
Unrealized changes in fair value of commodity derivatives and emission credits					(190)	3		
Consolidated revenues and other income and adjusted EBITDA					**941**	**968**	**544**	**451**

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 The Genesee 1 and 2 Power Purchase Arrangement (PPA) expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative period reflect energy sold on a contracted basis for Genesee 1 and 2 within the Alberta commercial grouping.

5 During the first quarter of 2021, management reviewed its facility groupings as a result of the change in classification of Genesee 1 and 2 as well as recent internal organizational changes. To best reflect how the Company operates, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be reported together as Western Canada contracted facilities with the Ontario contracted facilities in a separate grouping. Comparative figures have been reclassified to conform to the current period's presentation.

6 York Energy is accounted for under the equity method. Capital Power's share of the facility's net income is included in income from joint venture on the Company's condensed interim consolidated statements of income. Capital Power's share of the facility's adjusted EBITDA is included in adjusted EBITDA above. The equivalent of Capital Power's share of the facility's revenue was $7 million and $15 million for three and six months ended June 30, 2021, respectively, compared with $7 million and $15 million for the three and six months ended June 30, 2020. The facility's revenues are not included in the above results.

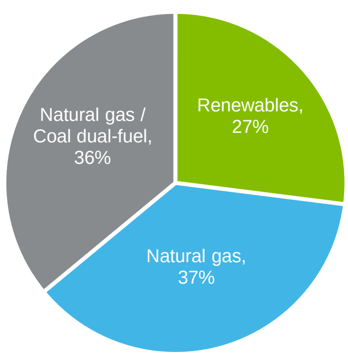
7 The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations. Decommissioning of the facilities commenced in the second quarter of 2021 and decommissioning costs are expected to be within the Company's established decommissioning provision.

8 Cardinal Point Wind was commissioned on March 16, 2020.

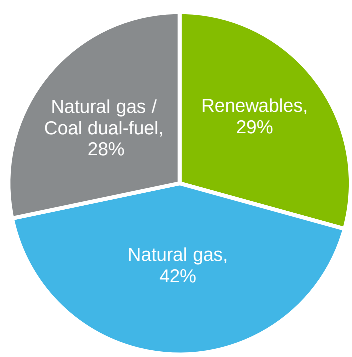
9 Buckthorn Wind was acquired on April 1, 2020.

10 Corporate revenues were offset by interplant category eliminations.

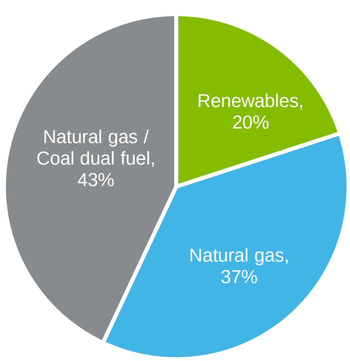
Adjusted EBITDA and revenues and other income by fuel type[1] for the six months ended June 30



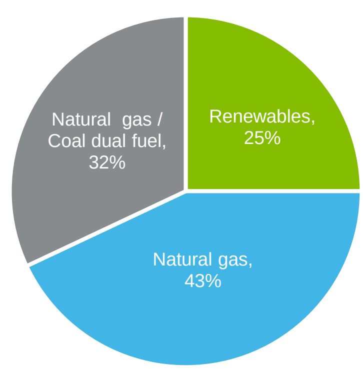
2021 Adjusted EBITDA by fuel type[1]



2020 Adjusted EBITDA by fuel type[1]



2021 Revenues and other income by fuel type[1]



2020 Revenues and other income by fuel type[1]

1 Alberta commercial EBITDA and revenues and other income is allocated to fuel source based on generation. The period-over-period increases in percentages from natural gas / coal dual-fuel are largely driven by significantly higher Alberta power prices in 2021 as compared to 2020.

Energy prices and hedged positions

		Three months ended June 30		Six months ended June 30		Year ended
Alberta	**Unit**	**2021**	**2020**	**2021**	**2020**	**December 31, 2020**
Hedged position [1]	Percentage sold forward at beginning of period (%)	51	100	38	77	72
Spot power price average	$ per megawatt hour (MWh)	105	30	100	48	47
Realized power price [2]	$ per MWh	75	53	76	58	58
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	3.03	1.90	3.05	1.95	2.16

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 TC Energy.

Alberta commercial facilities and portfolio optimization

The Alberta spot price averaged $105 per MWh and $100 per MWh for the three and six months ended June 30, 2021, respectively, which were significantly higher than the corresponding periods in 2020. The first and second quarters of 2021 each included one month of higher pricing as a result of cold and hot temperatures, respectively, and baseload facility outages. The remaining months settled at moderate pricing with stable baseload supply, but with higher monthly pricing in the 2021 months compared with 2020.

For the three and six months ended June 30, 2021, generation and availability were lower than the comparable periods in 2020, primarily due to a planned outage at Shepard in the second quarter of 2021, compared with no similar duration outages in the first half of 2020. In addition, Genesee 1 experienced more unplanned outages in 2021 compared with 2020. Most other facilities experienced no, shorter or less frequent unplanned outages in the first six months of 2021 compared with 2020. Generation for the six months ended June 30, 2021 was also impacted by lower CBEC dispatch in the first quarter of 2021 compared with 2020.

Revenues and other income for the three and six months ended June 30, 2021 were higher than the comparable periods in 2020 primarily due to higher Alberta spot power prices. The PPAs for Genesee 1 and 2 expired at the end of 2020, with subsequent revenue being on a merchant or non-contracted basis which led to increased revenues in the first six months of 2021 as compared to 2020 for Genesee 1 and 2. These revenue increases were partially offset by lower revenues from portfolio optimization activities as a result of power and natural gas forward sales contracts settling unfavourably against higher spot prices in 2021 compared with 2020.

Adjusted EBITDA for the three and six months ended June 30, 2021 was higher than the comparable periods in 2020 due largely to the aforementioned higher Alberta power prices in the first six months of 2021 compared with 2020. Additionally, natural gas expenses were lower in 2021 as a result of both lower fuel procurement from lower plant dispatch, as well as the impact of net forward purchase contracts settling favourably against higher spot prices. Partially offsetting these impacts were higher transmission expenses in the three and six months ended June 30, 2021 than in the comparable periods in 2020 due to the aforementioned higher spot power prices as well as an increase in Alberta emissions pricing in 2021 and higher emissions costs at the Genesee facilities, where upon the expiration of the PPAs for Genesee 1 and 2, emissions costs are no longer passed on to the PPA Buyer.

Western Canada contracted facilities

Generation for the three and six months ended June 30, 2021 was higher compared with the corresponding periods in 2020 primarily due to higher dispatch at Island Generation.

Availability for the three and six months ended June 30, 2021 was lower than the corresponding period in 2020 primarily due to an unplanned outage at Island Generation in the second quarter of 2021, compared with minimal unplanned outages in the corresponding periods of 2020. The availability variances at Island Generation were partially offset by less frequent and shorter outages at the EnPower facilities in the three and six months ended June 30, 2021, compared with the same periods in 2020.

Revenues and other income and adjusted EBITDA for the three and six months ended June 30, 2021 were lower compared with the corresponding periods in 2020 due to the noted outage at Island Generation and lower wind resource availability at Whitla Wind.

Ontario contracted facilities

Variances for generation, availability and revenues and other income for the three and six months ended June 30, 2021 compared to the corresponding periods in 2020 were primarily due to activities and results at Goreway.

Goreway experienced a longer planned outage in the second quarter of 2021 compared to the same period in 2020 but also experienced fewer and shorter unplanned outages in the six months ended June 30, 2021 compared with the same period in 2020. These outage variances, along with the level of dispatch contributed to the generation and availability variances at Goreway. In addition, East Windsor did not have a planned outage in the second quarter of 2021 as it did in the second quarter of 2020.

Revenues and other income at Goreway were lower in the second quarter of 2021 compared with 2020 primarily due to fewer system support opportunities and lower PPA revenues. Revenues and other income at Goreway were higher in the six months ended June 30, 2021 compared with the same period in 2020 primarily due to the noted impacts for the three month period being more than offset by higher captured pricing, primarily in the first quarter of 2021. Adjusted EBITDA at Goreway was lower in the three and six months ended June 30, 2021 compared with the same periods in 2020 primarily due to higher fuel pricing in the three and six months ended June 30, 2021 and higher costs related to the longer planned outage in the second quarter of 2021 compared with the corresponding period in 2020.

U.S. contracted facilities

Availability for the three and six months ended June 30, 2021 was lower than the comparable periods in 2020 primarily due to a longer planned outage at Decatur in 2021 compared with 2020 that occurred during the first and second quarters of each year. Partially offsetting the Decatur availability variance for the six months ended June 30, 2021 compared with the same period in 2020 was a shorter planned outage at Arlington Valley in 2021 compared with 2020 and no outages at the Southport and Roxboro facilities during their final quarter of operations in the first quarter of 2021.

The aforementioned availability variances were the primary drivers of the generation variances when comparing the three and six months ended June 30, 2021 to the same periods in 2020. In addition, for both the three and six month periods, the retirement of the Southport and Roxboro facilities reduced generation as did lower wind resource availability at Bloom Wind and New Frontier Wind. Generation variances for the six months ended June 30, 2021 were also driven by the commencement of operations at Cardinal Point Wind on March 16, 2020, the acquisition of Buckthorn Wind on April 1, 2020 and higher dispatch at Decatur in the first quarter of 2021 compared with 2020, despite more planned outage hours in the first quarter of 2021 compared with 2020 at that facility.

Revenues and other income for the three and six months ended June 30, 2021 were lower than the comparable periods in 2020 primarily due to the aforementioned availability and generation variances, as well as the impacts of a stronger Canadian dollar in 2021, partially offset by higher heat rate call option (HRCO) revenues driven by the impact of higher natural gas prices on the HRCO pricing at Arlington Valley in 2021 compared with 2020.

Adjusted EBITDA for the three months ended June 30, 2021 was lower than the comparable period in 2020 primarily due to the retirement of the Southport and Roxboro facilities effective March 31, 2021, higher Arlington Valley maintenance costs driven by timing, lower Decatur margins driven by the noted longer planned outage, the impacts of a stronger Canadian dollar in 2021 and the aforementioned lower wind availability at Bloom Wind and New Frontier Wind.

Adjusted EBITDA for the six months ended June 30, 2021 was higher than the comparable period in 2020 primarily due to the acquisition of Buckthorn Wind on April 1, 2020, the commencement of operations at Cardinal Point Wind on March 16, 2020 and higher Arlington Valley HRCO margins driven by the shorter planned outage in 2021 as compared with 2020. These favourable variances were largely offset by the retirement of the Southport and Roxboro facilities, the impacts of a stronger Canadian dollar in 2021 and the lower wind resource availability described above for the three months ended June 30, 2021.

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, people services, 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 higher for the three and six months ended June 30, 2021 compared with the same period in 2020 due to accelerated recognition of coal compensation revenue in 2021 as a result of the repowering of Genesee 1 and 2 announced in late 2020. Adjusted EBITDA for the three and six months ended June 30, 2021, was impacted by the acceleration of coal compensation revenue as well as the reversal of a contingent consideration provision that is no longer required related to a previous acquisition, partially offset by higher incentive expenses due to larger increases in the Company’s share price during the first half of 2021 as compared to decreases in the comparable period of 2020.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Three months ended June 30			
	2021	2020	2021	2020
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	(20)	(6)	1	(5)
Unrealized losses on U.S. power derivatives	(49)	(23)	(50)	(23)
Unrealized (losses) gains on natural gas derivatives	(66)	(4)	28	14
Unrealized (losses) gains on emission derivatives	(1)	1	(1)	1
Unrealized (losses) gains on emission credits held for trading	-	-	(2)	4
	(136)	**(32)**	**(24)**	**(9)**

(unaudited, $ millions)	Six months ended June 30			
	2021	2020	2021	2020
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	(22)	31	4	(11)
Unrealized losses on U.S. power derivatives	(84)	(18)	(84)	(18)
Unrealized (losses) gains on natural gas derivatives	(75)	(3)	57	13
Unrealized losses on emission derivatives	(9)	(7)	(9)	(7)
Unrealized gains (losses) on emission credits held for trading	-	-	1	(4)
	(190)	**3**	**(31)**	**(27)**

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 six months ended June 30, 2021, the Alberta power portfolio recognized unrealized gains of $1 million and $4 million respectively, due to the impact of increasing forward Alberta power pricing on forward purchase contracts, partially offset by the reversal of prior year unrealized gains on positions that settled during the period. For the comparable periods in 2020, the Alberta power portfolio recognized unrealized losses of $5 million and $11 million primarily due to the reversal of prior period unrealized gains on positions that settled during the period as well as the impact of decreasing forward Alberta power prices on the value of forward purchase contracts.

During the three and six months ended June 30, 2021, the U.S. power portfolio recognized unrealized losses of $50 million and $84 million respectively, as a result of the impact of increasing forward prices on the forward sales contracts associated with the Company's U.S. Wind facilities. During the comparable periods in 2020, the Company recognized unrealized losses of $23 million and $18 million, also due to the impact of increasing forward power prices on forward sale contracts.

During the three and six months ended June 30, 2021, the Company recognized unrealized gains on natural gas derivatives of $28 million and $57 million respectively, largely as a result of the impact of increasing forward natural gas pricing on the value of forward purchase contracts. During the comparable periods in 2020, the Company recognized unrealized gains of $14 million and $13 million respectively, which were also attributable to the impact of increasing forward natural gas pricing on the value of forward purchase contracts.

During the six months ended June 30, 2021, the Company recognized unrealized losses of $9 million on emission derivatives, as a result of the impact of increasing forward prices on forward sale contracts as well as the reversal of prior period unrealized gains on positions that settled during the period. During the six months ended June 30, 2020, the Company recognized unrealized losses of $7 million, as a result of decreasing forward prices on forward purchase contracts as well as the reversal of prior periods unrealized gains on positions that settled during the year.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Three months ended June 30		Six months ended June 30	
	2021	2020	2021	2020
Interest on borrowings less capitalized interest	(34)	(43)	(71)	(81)
Realized losses on settlement of interest rate derivatives	-	(1)	(2)	(1)
Other net finance expense – interest on coal compensation from the Province of Alberta, lease liability interest, sundry interest, guarantee and other fees	-	1	(1)	3
	(34)	(43)	(74)	(79)
Unrealized (losses) gains representing changes in the fair value of interest rate derivatives	(1)	-	9	(2)
Other net finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta	(11)	(6)	(22)	(12)
Total net finance expense	(46)	(49)	(87)	(93)
Depreciation and amortization	(135)	(121)	(270)	(241)
Impairment reversal (loss)	2	-	2	(13)
Foreign exchange (loss) gain	(2)	3	(1)	(6)
Finance expense and depreciation expense from joint venture	(5)	(6)	(5)	(19)
Income tax expense	(14)	(12)	(34)	(29)
Net loss attributable to non-controlling interests	3	-	5	2

Net finance expense

Lower net finance expense for the three months ended June 30, 2021 compared with the same period in the prior year largely reflects lower interest due to decreased loans and borrowings outstanding during the quarter, lower interest on a mid-January 2020 debt renewal and higher capitalized interest as a result of Whitla Wind 2 construction and the Genesee repowering project, partially offset by higher accretion due to accelerated coal compensation. On a year-to-date basis, lower net finance expense for the six months ended June 30, 2021 further reflects unrealized gains on non-hedge interest rate swaps driven by the impact of increasing market interest rates during 2021, partially offset by higher interest on tax equity financing related to the acquisition of Buckthorn Wind in the second quarter of 2020.

Depreciation and amortization

Depreciation and amortization for the three and six months ended June 30, 2021 increased compared with the same period in the prior year primarily due to the accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine as a result of the late 2020 Genesee repowering announcement. On a year-to-date basis, higher depreciation for the six months ended June 30, 2021, further resulted from Cardinal Point Wind (commenced commercial operations in March 2020) and the addition of Buckthorn Wind in the second quarter of 2020.

Impairment reversal (loss)

During the three and six months ended June 30, 2021, the Company recognized a pre-tax impairment reversal of $2 million related to the discontinuation of the Genesee 4 and 5 project for which the Company previously recognized a pre-tax impairment of $13 million during the six months ended June 30, 2020.

Foreign exchange (loss) gain

As at June 30, 2021, the Company had outstanding foreign currency non-hedge sales contracts totalling US$226 million. These contracts were transacted during the second quarter of 2021 and the Canadian dollar weakened against the U.S. dollar from that time to June 30, 2021 resulting in unrealized losses on these outstanding foreign currency non-hedge sales contracts. Partly offsetting these losses were realized gains from the impact of the strengthening of the Canadian dollar against the U.S. dollar during the three and six months ended June 30, 2021 on the settlement of foreign currency sales contracts in the period.

As at June 30, 2020, the Company had outstanding foreign currency non-hedge sales contracts totalling US$82 million. For the three months ended June 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 sales contracts, partially offset by realized losses on the settlement of foreign currency sales contracts in the quarter. For the six months ended June 30, 2020, the unrealized loss is mostly attributable to outstanding foreign currency non-hedge sales contracts in the first quarter of 2020, during which the Canadian dollar weakened against the U.S. dollar.

Finance expense and depreciation expense from joint venture

Finance expense and depreciation expense from joint venture 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 venture decreased by $14 million for the six months ended June 30, 2021 compared with the same period in 2020 due to increasing interest rates during 2021 resulting in gains on the interest rate non-hedge held within the York Energy joint venture, compared with declining interest rates during 2020 resulting in higher prior period expenses.

Income tax expense

For the three and six months ended June 30, 2021, income tax expense increased $2 million and $5 million, respectively, compared with the corresponding periods in 2020 primarily due to higher overall consolidated income before tax. This was partially offset by a $10 million deferred tax benefit from lower applicable jurisdiction tax rates, for which no comparable tax recovery was recognized in 2020 and other rate differences associated with foreign exchange movements.

Non-controlling interests

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

COMPREHENSIVE (LOSS) INCOME

(unaudited, $ millions)	Three months ended June 30		Six months ended June 30	
	2021	**2020**	**2021**	**2020**
Net income	17	23	118	23
Other comprehensive (loss) income:				
Net unrealized (losses) gains on derivative instruments	(101)	6	(108)	(10)
Net realized losses (gains) on derivative instruments reclassified to net income	52	(18)	88	(7)
Unrealized foreign exchange (losses) gains on the translation of foreign operations	(5)	(37)	(18)	47
Actuarial gain related to the Company's defined benefit pension plan	-	-	-	3
Total other comprehensive (loss) income, net of tax	(54)	(49)	(38)	33
Comprehensive (loss) income	**(37)**	**(26)**	**80**	**56**

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 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, 2020 to June 30, 2021 were as follows:

(unaudited, $ millions)	As at June 30, 2021	As at December 31, 2020	Increase (decrease)	Primary reason for increase (decrease)
Trade and other receivables	419	499	(80)	Decrease primarily due to a reduction in capacity payment accrued receivables and emission expense recovery resulting from the expiration of the Genesee PPA with the Balancing Pool and collection of receivables outstanding at December 2020, partially offset by higher settled Alberta pool prices in June 2021 compared to December 2020.
Property, plant and equipment	6,028	6,098	(70)	Decrease due to useful life changes (resulting from updated timelines at Genesee 1 and 2 for Repowering), the impact of increasing interest rates on decommissioning assets, foreign exchange impacts and depreciation. These impacts were partially offset by capital additions for Genesee Repowering, Strathmore Solar and

(unaudited, $ millions)	As at June 30, 2021	As at December 31, 2020	Increase (decrease)	Primary reason for increase (decrease)
				Whitla Wind 2 as well as turbine upgrades at Decatur Energy.
Net derivative financial instruments liabilities	107	55	52	Increase primarily due to increasing forward prices on U.S. contracted wind forward sales contracts and increasing Alberta forward power prices on net forward sales contracts partially offset by increasing forward natural gas prices on net forward purchase contracts and increasing forward interest rates on interest rate swaps.
Loans and borrowings (including current portion)	2,983	3,552	(569)	Decrease primarily due to repayments of U.S. dollar bank loans, net repayments of credit facilities and allocation of income tax benefits to tax-equity investors associated with the Company’s tax-equity structures.
Deferred revenue and other liabilities (including current portion)	379	412	(33)	Decrease primarily due to amortization of coal compensation and the reclassification of Arlington Valley long-term service agreement costs to trade and other payables, partially offset by increased spending on the Genesee Repowering project for which payments are being deferred.
Provisions (including current portion)	449	501	(52)	Decrease mainly due to revisions to existing decommissioning provisions driven by increases in interest rates.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Six months ended June 30		
Cash inflows (outflows)	**2021**	**2020**	**Change**
Operating activities	335	194	141
Investing activities	(241)	(264)	23
Financing activities	(328)	(91)	(237)

Operating activities

Cash flows from operating activities for the six months ended June 30, 2021 increased compared with the same period in 2020 mainly due to (i) the cash flow impacts of the increases in adjusted EBITDA described in Consolidated Net Income and Results of Operations, including the acquisition of Buckthorn Wind in the second quarter of 2020, the commissioning of Cardinal Point Wind in March 2020 and higher realized Alberta power pricing offset partly by higher Alberta emissions costs including higher emissions pricing and the assumption of the obligation for Genesee 1 and Genesee 2 emissions costs in 2021, (ii) realized gains on the settlement of interest rate derivatives during the second quarter of 2021, (iii) a decrease in income taxes paid, and (iv) less unfavourable 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 in the first half of 2021 compared with the same period in 2020. These increases were partially offset by (i) the timing of the 2020 annual emissions settlement which occurred during the second quarter of 2021 as compared to during the first half of 2020 where only the obligation for the fourth quarter of 2019 was settled, and (ii) net settlements of tranches 2 and 3 of the LLR Proceeding invoices during the first half of 2021.

Investing activities

Cash flows used in investing activities for the six months ended June 30, 2021 decreased compared with the same period in 2020 primarily due to the acquisition of Buckthorn Wind in the second quarter of 2020, partly offset by higher cash capital expenditures in 2021 (net of changes in non-cash investing working capital and deferred payments relating to repowering capital expenditures in 2021).

Capital expenditures and investments

(unaudited, $ millions)	Pre-2021 actual	Six months ended June 30, 2021 actual	Balance of 2021 estimated [1,2]	Actual or projected total [2]	Targeted completion
Repowering of Genesee 1 and 2	-	77	189	997	Unit 1 in 2023 and Unit 2 in 2024
Whitla Wind 2 and 3	33	88	136	257	Fourth quarter of 2021
Strathmore Solar	2	16	36	53	First quarter of 2022
Enchant Solar	1	1	25	102	Fourth quarter of 2022
Bear Branch Solar	1	-	1	60	Fourth quarter of 2022
Hornet Solar	1	-	2	118	Fourth quarter of 2022
Hunter's Cove Solar	1	-	2	82	Fourth quarter of 2022
Commercial initiatives [3]	154	18	11	198	
Development sites and projects	24	-	-		
Subtotal growth projects		**200**	**402**		
Sustaining – plant maintenance excluding Genesee mine		51			
Sustaining – Genesee mine maintenance and lands		3			
Total capital expenditures [4]		**54**			
Emission credits held for compliance		49			
Investment in C2CNT		13			
Capitalized interest		(3)			
Purchase of property, plant and equipment and other assets		**313**			

1 The Company's 2021 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 ongoing projects 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 Commercial initiatives include the combustion turbine upgrade project for Decatur Energy with capital expenditures incurred life-to-date to the end of June 30, 2021 of $77 million (US$58 million). The final stage of this project will result in an additional 30 MW of generation in 2021 (an additional 60 MW of generation was completed prior to 2021). 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.

4 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

Cash flows used in financing activities were higher in the six months ended June 30, 2021 mainly due to higher net repayments of loans and borrowings and the prior year issuance of approximately $221 million (US$157 million) in net tax equity financing related to Cardinal Point Wind. Partially offsetting these higher cash outflows were the issuance of common shares in 2021 (see Significant Events), lower common share dividends paid in 2021 as result of the reinstatement of the Company's Dividend Reinvestment Plan in the third quarter of 2020 and lower repurchases of common shares under the Company's normal course issuer bid.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at June 30, 2021			As at December 31, 2020		
	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			15			9	
Bankers' acceptances outstanding			-			-	
Bank loans outstanding [1]			-			193	
		1,000	15	985	1,000	202	798
Bilateral demand credit facilities	N/A	424			427		
Letters of credit outstanding			298			259	
		424	298	126	427	259	168
Demand credit facilities	N/A	25	-	25	25	-	25
		1,449	**313**	**1,136**	**1,452**	**461**	**991**

[1] U.S. dollar denominated bank loans outstanding totaling nil (December 31, 2020 – US$151 million).

As at June 30, 2021, the committed credit facility utilization decreased $187 million compared with the utilization as at December 31, 2020, due to repayment of U.S. dollar bank loans. The available credit facilities provide the Company with adequate funding for ongoing development projects. Subsequent to the second quarter of 2021, the Company amended and transitioned its existing $1 billion of committed credit facilities to SLCs and extended their maturity to July 2026 (see Subsequent Events).

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 16, 2021. 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, 2021. 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 2021 include:

(unaudited, $ millions)	Six months ended June 30, 2021 actual	Balance of 2021 estimated	Total 2021 expected cash requirements
Repayment of debt payable [1]	311	32	343
Interest on loans and borrowings	61	47	108
Capital expenditures – sustaining	47	44	91
Capital expenditures – ongoing growth projects [2]	154	296	450
Capital expenditures – commercial initiatives	18	11	29
Common share dividends [3]	79	86	165
Preferred share dividends	26	25	51
	696	**541**	**1,237**

1 Excludes repayment of credit facilities.

2 Excludes capital expenditures on the Genesee 1 and 2 repowering project for which payments are deferred.

3 Includes 6.8% annual dividend growth (see Subsequent 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, 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.

Off-statement of financial position arrangements

As at June 30, 2021, the Company has $313 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements and to satisfy legislated reclamation requirements. If the Company were to terminate these off-statement of financial position arrangements, the penalties or obligations would not have a material impact on the Company's financial condition, results of operations, liquidity, capital expenditures or resources.

Capital resources

(unaudited, $ millions)	As at	
	June 30, 2021	December 31, 2020
Loans and borrowings	2,983	3,552
Lease liabilities [1]	141	149
Less cash and cash equivalents	(138)	(367)
Net debt	2,986	3,334
Share capital	3,790	3,465
Deficit and other reserves	(623)	(565)
Non-controlling interests	24	29
Total equity	3,191	2,929
Total capital	**6,177**	**6,263**

1 Includes the current portion presented within deferred revenue and other liabilities.

CONTINGENT LIABILITIES AND PROVISIONS

Refer to Contractual Obligations, Contingent Liabilities, Other Legal Matters and Provisions discussion in the Company's 2020 Integrated Annual Report for further details that supplement the recent developments discussed below:

Contingent liabilities

The Company and its subsidiaries are subject to various legal claims, including the dispute disclosed in the Significant Events section, that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial.

Other legal matters

In each of 2017 through 2020, the Government of Alberta (GoA) withheld approximately $2.7 million from the Company's annual off-coal payment, on the basis of an alleged "implied term" of the Off-Coal Agreement. Capital Power believes there was no such implied term and has therefore sued the GoA for recovery of the withheld amount and specific performance for future payments. The status of this matter remains unchanged from what has been previously disclosed in the Company's 2020 Integrated Annual Report. Assuming that leave to the Court of Appeal is granted, it is expected that a final Court of Appeal decision will not be available until the first quarter of 2022.

Line Loss Rule Proceeding

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.

Based on current AUC decisions, Capital Power will incur additional charges related to historical periods and, as such, has previously recorded $19 million pertaining to the Company's estimated net liability. The amount reflects a decrease of $1 million recorded during the first quarter of 2021 to reflect final tranche 3 invoices received during this period. The invoicing process results in gross billings to Capital Power of which those amounts not attributable to Capital Power will then be recoverable from the appropriate parties. Recovery of these amounts, with the exception of those related to the Sundance C PPA from the Balancing Pool, has proceeded as expected.

On January 26, 2021, the AUC rendered a decision in which it ordered the use of simple interest, aligning with the approach reflected in the AESO's issued invoices. An application seeking to rehear and overturn this decision was filed with the AUC on March 26, 2021. Capital Power actively participated in these proceedings. The AUC issued a favourable decision on June 22, 2021 denying this application. The party that applied for a direction for compound interest filed an application to the Alberta Court of Appeal for permission to appeal the AUC's decision which application is presently scheduled to be heard in the third quarter of 2021. Resolution of this limited issue may not occur in 2021.

The AESO has completed the primary invoicing process for all three tranches of invoices covering the years 2006-2016 which were paid by the Company in December 2020, February 2021 and May 2021, respectively. The amounts invoiced to Capital Power but not attributable to the Company have been invoiced to the appropriate parties for recovery with significant portions received by the Company in December 2020, February 2021 and May 2021. A further invoice from the AESO is now expected in October 2021 to address trailing amounts and correct calculation errors uncovered during the invoicing process. Based on the information currently available, these are not expected to significantly impact the net amounts paid by the Company.

The Balancing Pool is disputing its liability to make payment for the LLR adjustment invoices related to the Sundance C PPA, which amounts to a net potential exposure to Capital Power of approximately $25 million. The Company believes the various agreements governing the termination and transfer of the Sundance C PPA and related transmission agreements with the AESO had the effect of transferring all past liabilities for the Sundance C PPA to the Balancing Pool. Capital Power has therefore filed a statement of claim at the Alberta Court of Queen's Bench on January 11, 2021 against the Balancing Pool, the Province of Alberta and the AESO in which it is seeking, among other relief, recovery from the Balancing Pool and the Province of Alberta of all amounts Capital Power is compelled to pay to the AESO on account of the LLR adjustment invoices relating to the Sundance C PPA as well as interest and legal costs, including the portion invoiced to the Balancing Pool but not received by the Company pertaining to all tranches of invoices. This process remains ongoing. Capital Power expects to ultimately realize the full amount of the gross receivables related to the line losses upon resolution of the dispute before the Court.

RISKS AND RISK MANAGEMENT

There have been no material changes in the six months ended June 30, 2021 to the Company's business and operational risks as described in the Company's 2020 Integrated Annual Report. Information pertaining to climate-related risks and opportunities can be found on the Company's website within its 2020 Climate Change Disclosure

Report.

The COVID-19 pandemic situation remains 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 developments on the Company's risk exposures described in the Company's 2020 Integrated Annual Report and key strategies for mitigating those risks have not materially changed in the six months ended June 30, 2021. The COVID-19 pandemic is ongoing to varying degrees in the regions in which the Company operates and may continue in some form for an extended period. There is no certainty to when the pandemic will be fully brought under control with cases of COVID-19 variants on the rise in some regions and the potential for additional "waves" of COVID-19 occurring or anticipated in various regions in which the Company operates. However, vaccination efforts in North America have progressed and in many of the Company's operating regions, COVID-19 case numbers have declined notably and government restrictions have continued to ease.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $361 million as at June 30, 2021 ($414 million as at December 31, 2020) for its generation facilities and the Genesee 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 Mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation. The timing of reclamation activities could vary and the amount of decommissioning provisions could change depending on potential future changes in environmental regulations and the timing of any facility fuel conversions.

The Company has forward contracts to purchase environmental credits totaling $403 million and forward contracts to sell environmental credits totaling $422 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

Refer to Regulatory Matters discussion in the Company's 2020 Integrated Annual for further details that supplement the recent developments discussed below:

Canada

On December 11, 2020, the Government of Canada released its updated climate plan (the Federal Plan). The Federal Plan sets out a range of measures and proposed policies across multiple sectors that are intended to enable Canada to meet and exceed its current 2030 greenhouse gas reduction commitments under the Paris Agreement, and also set Canada on a path to achieving net-zero carbon emissions by 2050. Among other things, the Federal Plan proposes to increase the carbon price by $15 per tonne per year after 2022 until achieving a price of $170 per tonne in 2030.

On April 22, 2021, Prime Minister Trudeau announced that Canada will increase its emissions reduction target under the Paris Agreement to be 40-45% below 2005 levels by 2030, compared to the previous target of 30%. The 40 – 45% emissions reduction was subsequently incorporated in the Canadian Net-Zero Emissions Accountability Act (*Act*), which received Royal Assent on June 29, 2021, and was reflected in Canada's enhanced Nationally Determined Contribution (NDC) that was submitted to the United Nations on July 12, 2021.

The Federal Government also confirmed in July 2021 that the minimum price on carbon will increase by $15 per tonne each year starting in 2023 to a level of $170 per tonne in 2030, as set out in the Federal Plan, and advised that the "benchmark" stringency framework will be updated to ensure all provincial and territorial pricing systems are comparable in terms of stringency and effectiveness. Provinces and territories will continue to have the flexibility to implement the type of system that makes sense for their circumstances as long as they align with the benchmark.

Additional information or details regarding sector-specific targets or measures arising from the new targets, relative to the policies that have been outlined in the Federal Plan, have not been provided at this time. The Company will incorporate the new targets as part of its ongoing assessment of the potential impacts of Federal carbon policy for Capital Power's existing facilities and prospective interests in the Canadian market. The Company also continues to engage with Federal Government officials regarding carbon policy-related matters and is participating in relevant policy development processes.

Alberta

On January 1, 2020, the Government of Alberta (GOA) replaced the Carbon Competitiveness Incentive Regulation (CCIR) with the TIER Regulation for large industrial emitters. On November 5, 2020 the Government of Alberta increased the carbon price under the TIER Regulation for the 2021 calendar year to $40 per tonne of carbon dioxide equivalent.

In March 2021, the Government of Alberta initiated a Climate Policy Engagement process through which it intends to seek input from stakeholders and industry sectors, including electricity, regarding various aspects of Alberta's carbon policy framework. Capital Power understands the process is intended to gather input that will inform Alberta's future policies and programs. The Company is participating in the process.

The Supreme Court of Canada (the Court) released its decision regarding the challenge filed by the governments of Alberta, Saskatchewan, Manitoba and Ontario regarding the constitutionality of the Greenhouse Gas Pollution Pricing Act (GGPPA). In a 6-3 decision, the majority of the Court upheld the constitutionality of the GGPPA and determined that the GGPPA "sets minimum national standards of GHG price stringency to reduce GHG emissions". The Governments of Alberta and Ontario have indicated they will be reviewing the decision in detail before determining next steps.

On June 22, 2021, the GOA started a consultation process to develop new surface water quality management frameworks for the North Saskatchewan, Battle and Upper Athabasca rivers. The water quality management frameworks establish clear regional objectives for water quality. The Company will participate in the consultation process since Genesee and Clover Bar Energy Centre are located on the North Saskatchewan River.

At midnight on December 31, 2020, the PPA Regulation in Alberta expired and on January 1, 2021, all remaining PPAs held by the Balancing Pool have reverted back to their respective generation facility owners. Dispatch and offer control of Genesee 1 and 2, previously under PPA with the Balancing Pool as the Buyer, now reside with the Company.

Ontario

Ontario's Independent Electric System Operator (IESO) is continuing work under its Market Renewal Program (MRP) which is a series of coordinated market reforms expected to result in a fundamental redesign of Ontario's electricity market. The IESO's stated goal for the MRP is to improve how electricity is priced, scheduled and procured to meet Ontario's electricity system needs. The Company is actively participating in the MRP stakeholder process and collaborating with the IESO.

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. On December 16, 2020, the MECP started consultation with stakeholders, including Capital Power, about the transition of Ontario industrial facilities from the Federal Output-Based Pricing System (OBPS) to the provincial EPS. Environment and Climate Change Canada has recently announced that Ontario's EPS will be in effect for the year 2022. On May 27, 2021 MECP proposed additional amendments to the EPS to further support the transition of industry from federal OBPS to Ontario's EPS program, including the proposal that the electricity benchmark will be a 0.37 tonne of carbon dioxide equivalent per megawatt-hour (t/MWh) instead of the 0.42 t/MWh that was in effect under Ontario's previous EPS.

Until the transition is completed, York Energy, East Windsor and Goreway remain subject to the federal GGPPA and the federal carbon price of $30 per tonne in 2020 and $40 per tonne in 2021. 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 in Ontario 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.

The Ontario Ministry of Energy, Northern Development and Mines (MENDM) announced on January 5, 2021 that the regulation requiring the release of the Long-term Energy Plan (LTEP) every three years has been revoked effective January 1, 2021. According to the MENDM notice, removal of this requirement is part of its plan to reform the province's long-term energy planning process. Development of a new framework intended to eliminate political interference, increase transparency, and augment accountability in the planning process was consulted on in the first and second quarters of 2021. No significant impact to the Company and its assets is expected.

British Columbia

BC Hydro published their draft Integrated Resource Plan (IRP) in June. The draft references that BC Hydro is not currently intending to renew the long-term Electricity Purchase Agreement (EPA) for Capital Power's Island Generation facility at Campbell River on Vancouver Island, which expires in April 2022. The Company continues to believe the Island Generation facility is needed to ensure secure and reliable electricity supply for homes and businesses on Vancouver Island and in Metro Vancouver and will actively participate in BC Hydro's consultation process and the following regulatory process. BC Hydro will be incorporating feedback into its final IRP which is due to be filed with the BC Utilities Commission by the end of 2021.

The current carrying amount of the property, plant and equipment of Island Generation at June 30, 2021 is $101 million.

United States

Following the November 3, 2020 U.S. presidential election, the Biden Administration has pursued a “whole of government” effort to address clean energy and climate change outlined via Executive Orders, including Executive Branch and Congressional efforts. Key risks will relate to how these efforts impact natural gas, while low carbon technologies and renewable energy stand to benefit with some caveats regarding new social license requirements.

In its entirety, the effort will include a broad range of regulatory and funding actions by the Executive Branch under existing statutory authority. These actions will range from new regulatory requirements under the Environmental Protection Agency’s Clean Air Act authority to enhanced funding for climate mitigation at the Department of Energy to new climate and sustainability risk disclosure requirements at the Securities and Exchange Commission. Legislatively, a broad US$1.9 trillion infrastructure package is being addressed through Congressional action.

The legislative package is highly political and subject to significant negotiation before being passed by Congress and signed into law by the President. However, several risks and opportunities are embedded in these legislative proposals, best articulated in the President’s American Jobs Plan. Some of the key provisions relevant to Capital Power include the following: (i) potential increases in the corporate tax rate, (ii) establishment of a national Clean Energy Standard that would set a goal of zero carbon emissions in the power sector by 2035, (iii) extension and enhancement or reform of tax credits that benefit clean energy investment and production, and (iv) billions of dollars in grants and loans towards research, development and deployment of low carbon technologies such as carbon capture, utilization and storage and Direct Air Capture.

With respect to renewable energy support whether through legislation or regulatory action, the Biden administration’s priorities seek to increase pressure on the sector to increase labor standards and seek a more sustainable and U.S. manufactured/procured supply chain in the development process. In addition, a range of new Environmental Justice requirements are also possible in the clean energy sector.

Management continues to monitor these developments closely as they progress as they could have significant impacts on Capital Power.

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 Integrated Annual Report.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at June 30, 2021 and December 31, 2020 were as follows:

(unaudited, $ millions)		June 30, 2021		December 31, 2020	
	Fair value hierarchy level [1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	138	138	367	367
Trade and other receivables [2]	N/A	363	363	445	445
Government grant receivable [3]	Level 2	448	445	441	448
Fair value through income or loss					
Derivative financial instruments assets – current and non-current	See below	270	270	238	238
Fair value through other comprehensive income					
Derivative financial instruments assets – current and non-current	See below	16	16	10	10
Financial liabilities:					
Other financial liabilities					
Trade and other payables	N/A	478	478	470	470
Loans and borrowings [3]	Level 2	2,983	3,192	3,552	3,838
Fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See below	244	244	160	160
Fair value through other comprehensive income					
Derivative financial instruments liabilities – current and non-current	See below	149	149	143	143

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

2 Excludes current portion of government grant receivable.

3 Includes current portion.

Risk management and hedging activities

There have been no material changes in the six months ended June 30, 2021 to the Company's risk management and hedging activities as described in the Company's 2020 Integrated Annual Report.

The derivative financial instruments assets and liabilities held at June 30, 2021 compared with December 31, 2020 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at June 30, 2021						
	Fair value hierarchy level	Commodity cash flow hedges	Commodity non-hedges	Interest rate cash flow hedges	Interest rate non-hedges	Foreign exchange cash flow-hedges	Foreign exchange non-hedges	Total
Derivative financial instruments assets	Level 2	3	253	13	9	-	-	278
	Level 3	-	8	-	-	-	-	8
		3	261	13	9	-	-	286
Derivative financial instruments liabilities	Level 2	(55)	(187)	(84)	(1)	(10)	(6)	(343)
	Level 3	-	(50)	-	-	-	-	(50)
		(55)	(237)	(84)	(1)	(10)	(6)	(393)
Net derivative financial instruments (liabilities) assets		**(52)**	**24**	**(71)**	**8**	**(10)**	**(6)**	**(107)**

(unaudited, $ millions)		As at December 31, 2020					
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Interest rate non-hedges**	**Foreign exchange cash-flow hedges**	**Total**
Derivative financial instruments assets	Level 2	2	172	8	-	-	182
	Level 3	-	66	-	-	-	66
		2	238	8	-	-	248
Derivative financial instruments liabilities	Level 2	(31)	(128)	(97)	(1)	(15)	(272)
	Level 3	-	(31)	-	-	-	(31)
		(31)	(159)	(97)	(1)	(15)	(303)
Net derivative financial instruments (liabilities) assets		**(29)**	**79**	**(89)**	**(1)**	**(15)**	**(55)**

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

Unrealized gains and losses for fair value changes on commodity, interest rate and foreign exchange derivatives that qualify for hedge accounting are recorded in other comprehensive income (loss) and, when realized, are reclassified to net income as revenues, energy purchases and fuel, finance expense or foreign exchange gains and losses as appropriate. When interest rate derivatives are used to hedge the interest rate on a future debt issuance, realized gains or losses are deferred within accumulated other comprehensive income (loss) and recognized within finance expense over the life of the debt, consistent with the interest expense on the hedged debt. When foreign exchange derivatives are used to hedge the risk of variability in cash flows resulting from foreign currency exchange rate fluctuations on future capital expenditures, realized gains and losses are deferred within accumulated other comprehensive income (loss) and then recorded in property, plant and equipment and amortized through depreciation and amortization over the estimated useful life of the hedged property, plant and equipment.

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

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

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

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no significant changes in the Company's disclosure controls and procedures and internal controls over financial reporting that occurred during the six months ended June 30, 2021 that have materially affected or are reasonably likely to materially affect the Company's disclosures of required information and internal control over financial reporting.

SUMMARY OF QUARTERLY RESULTS

(GWh)	Three months ended							
Electricity generation	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Total generation	4,975	5,630	6,445	6,327	5,472	5,562	6,437	6,808
Alberta commercial facilities[1]								
Genesee 1	708	616	807	739	689	792	848	803
Genesee 2	701	581	791	696	618	773	826	795
Genesee 3	951	904	928	1,014	926	913	1,015	492
Keephills 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	450
Clover Bar Energy Centre 1, 2 and 3	67	23	112	98	79	196	135	348
Joffre	180	203	209	171	132	186	187	150
Shepard	379	803	839	784	770	867	660	782
Halkirk Wind	111	151	150	117	121	148	129	86
Clover Bar Landfill Gas	-	-	-	1	1	1	-	-
	3,097	3,281	3,836	3,620	3,336	3,876	3,800	3,906
Western Canada contracted facilities[1,2]								
Island Generation	114	28	4	47	-	7	8	379
Quality Wind	83	127	128	108	99	122	130	73
EnPower	7	11	8	2	3	10	10	3
Whitla Wind 1	178	235	258	170	192	238	77	N/A
	382	401	398	327	294	377	225	455
Ontario contracted facilities[2]								
York Energy	5	4	3	4	3	4	5	3
East Windsor	4	-	1	2	2	1	4	2
Goreway	159	234	279	329	217	143	157	304
Kingsbridge 1	20	30	36	15	21	32	34	15
Port Dover and Nanticoke	66	81	95	53	70	90	84	46
	254	349	414	403	313	270	284	370
U.S. contracted facilities								
Roxboro, North Carolina[3]	N/A	57	81	84	84	81	86	88
Southport, North Carolina[3]	N/A	60	95	100	114	105	127	112
Decatur Energy, Alabama	240	356	369	665	327	124	656	709
Arlington Valley, Arizona	461	545	644	693	404	377	912	878
Beaufort Solar, North Carolina	8	6	6	8	8	6	6	8
Bloom Wind, Kansas	177	165	179	154	212	183	197	176
Macho Springs Wind, New Mexico	41	38	30	21	43	35	29	21
New Frontier Wind, North Dakota	93	103	120	95	102	110	115	85
Cardinal Point Wind, Illinois	141	170	170	86	138	18	N/A	N/A
Buckthorn Wind, Texas	81	99	103	71	97	N/A	N/A	N/A
	1,242	1,599	1,797	1,977	1,529	1,039	2,128	2,077

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative periods reflect power sold on a contracted basis for Genesee 1 and 2 within the Alberta commercial grouping.

2 During the first quarter of 2021, management has reviewed its facility groupings as a result of the change in classification of Genesee 1 and 2 as well as recent internal organizational changes. To best reflect how the Company operates, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be reported together as Western Canada contracted facilities with the Ontario contracted facilities in a separate grouping. Comparative figures have been reclassified to conform to the current period's presentation.

3 The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations.

(%)	Three months ended							
Facility availability	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Total average facility availability	84	96	97	98	92	91	94	96
Alberta commercial facilities [1]								
Genesee 1	92	92	96	100	100	96	100	96
Genesee 2	100	100	98	100	97	97	100	100
Genesee 3	95	95	93	100	95	92	100	96
Keephills 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	93
Clover Bar Energy Centre 1, 2 and 3	94	99	91	98	90	97	86	96
Joffre	95	100	99	99	100	93	89	82
Shepard	50	100	100	100	99	100	79	100
Halkirk Wind	98	98	97	96	99	98	99	95
Clover Bar Landfill Gas	-	-	-	37	48	53	-	-
	87	97	96	99	97	96	93	96
Western Canada contracted facilities [1, 2]								
Island Generation	89	100	100	100	100	100	92	99
Quality Wind	98	97	97	98	98	96	98	96
EnPower	93	89	98	100	74	86	91	72
Whitla Wind 1	98	98	99	98	97	97	97	N/A
	94	98	99	99	98	98	94	97
Ontario contracted facilities [2]								
York Energy	100	100	100	98	100	100	94	99
East Windsor	100	99	94	99	96	99	97	99
Goreway	89	99	95	93	96	88	88	87
Kingsbridge 1	98	99	100	98	98	99	99	98
Port Dover and Nanticoke	99	99	98	93	99	99	97	94
	93	99	96	94	97	92	91	91
U.S. contracted facilities								
Roxboro, North Carolina [3]	N/A	100	100	99	99	90	88	99
Southport, North Carolina [3]	N/A	100	99	98	100	85	96	84
Decatur Energy, Alabama	51	79	100	100	73	87	93	100
Arlington Valley, Arizona	78	99	96	99	77	66	99	100
Beaufort Solar, North Carolina	97	99	98	99	100	100	98	100
Bloom Wind, Kansas	98	95	99	95	98	99	99	98
Macho Springs Wind, New Mexico	98	98	98	97	98	99	98	97
New Frontier Wind, North Dakota	97	94	93	97	98	98	94	97
Cardinal Point Wind, Illinois	97	99	97	92	95	89	N/A	N/A
Buckthorn Wind, Texas	94	94	96	94	95	N/A	N/A	N/A
	72	90	98	98	82	83	96	99

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative periods reflect power sold on a contracted basis for Genesee 1 and 2 within the Alberta commercial grouping.

2 During the first quarter of 2021, management has reviewed its facility groupings as a result of the change in classification of Genesee 1 and 2 as well as recent internal organizational changes. To best reflect how the Company operates, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be reported together as Western Canada contracted facilities with the Ontario contracted facilities in a separate grouping. Comparative figures have been reclassified to conform to the current period's presentation.

3 The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations.

Financial results

(unaudited, $ millions)	Three months ended							
	Jun 30 2021	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Revenues and other income								
Alberta commercial facilities and portfolio optimization[1]	314	343	245	274	241	276	284	249
Western Canada contracted facilities [1,2]	25	37	38	29	27	37	30	19
Ontario contracted facilities [2]	66	80	84	70	70	73	75	69
U.S. contracted facilities	86	118	112	133	117	101	103	149
Corporate [3]	32	30	19	13	12	11	141	15
Unrealized changes in fair value of commodity derivatives and emission credits	(136)	(54)	18	(66)	(32)	35	50	16
	387	**554**	**516**	**453**	**435**	**533**	**683**	**517**
Adjusted EBITDA								
Alberta commercial facilities and portfolio optimization[1]	136	165	99	131	106	132	134	121
Western Canada contracted facilities[1, 2]	18	29	31	22	21	30	25	14
Ontario contracted facilities [2,4]	49	57	61	52	56	58	55	49
U.S. contracted facilities	35	55	47	96	56	31	40	115
Corporate	3	(3)	(18)	(17)	(22)	(17)	98	(15)
	241	**303**	**220**	**284**	**217**	**234**	**352**	**284**

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Results for the comparative periods reflect power sold on a contracted basis for Genesee 1 and 2 within the Alberta commercial grouping.

2 During the first quarter of 2021, management has reviewed its facility groupings as a result of the change in classification of Genesee 1 and 2 as well as recent internal organizational changes. To best reflect how the Company operates, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be reported together as Western Canada contracted facilities with the Ontario contracted facilities in a separate grouping. Comparative figures have been reclassified to conform to the current period's presentation.

3 Revenues are offset by interplant category revenue eliminations

4 The reported Ontario contracted facilities' adjusted EBITDA includes the adjusted EBITDA from the York Energy joint venture.

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, and planned and unplanned facility outages and items outside the normal course of operations. Net income (loss) is also affected by changes in the fair value of the Company's power, natural gas, interest rate and foreign exchange derivative contracts.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Jun 30 2021	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Revenues and other income	387	554	516	453	435	533	683	517
Adjusted EBITDA [1, 2,]	241	303	220	284	217	234	352	284
Net income (loss)	17	101	1	106	23	-	181	(228)
Net income (loss) attributable to shareholders of the Company	20	103	3	108	23	2	182	(226)
Basic earnings (loss) per share ($)	0.05	0.83	(0.09)	0.89	0.10	(0.11)	1.61	(2.25)
Diluted earnings (loss) per share ($)[3]	0.05	0.83	(0.09)	0.89	0.09	(0.11)	1.60	(2.25)
Normalized earnings per share ($) [1]	0.32	0.64	0.12	0.66	0.17	0.27	0.29	0.60
Net cash flows from operating activities	129	206	159	258	91	103	201	209
Adjusted funds from operations [1]	91	159	86	221	97	118	128	225
Adjusted funds from operations per share ($) [1]	0.83	1.49	0.81	2.10	0.92	1.12	1.22	2.11
Purchase of property, plant and equipment and other assets	188	125	70	50	87	99	112	193

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

2 The reported Ontario contracted facilities' adjusted EBITDA includes the adjusted EBITDA from the York Energy joint venture.

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

	Three months ended							
Spot price averages	**Jun 30 2021**	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Alberta power ($ per MWh)	105	95	46	44	30	67	47	47
Alberta natural gas (AECO) ($ per Gj)	3.03	3.07	2.52	2.17	1.90	1.99	2.32	0.99
Capital Power's Alberta portfolio average realized power price ($ per MWh)	75	77	56	59	53	62	57	59

Factors impacting results for the previous quarters

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

For the quarter ended March 31, 2021, the Company recorded net income attributable to shareholders of $103 million compared to net income attributable to shareholders of $2 million for the quarter ended March 31, 2020. Increases in net income were due largely to higher adjusted EBITDA from: Alberta commercial facilities due to higher realized Alberta power prices and the dispatch of Genesee 1 and 2 being on a merchant basis, the accelerated recognition of coal compensation revenue, the acquisition of Buckthorn Wind in the second quarter of 2020 and the commissioning of Cardinal Point Wind late in the first quarter of 2020. Unrealized losses on commodity derivatives and emission credits were $11 million lower than in the first quarter of 2020 mainly due to the impact of increasing forward prices resulting in unrealized gains on commodity forward purchase contracts, partially offset by unrealized losses on U.S. power forward sales contracts. Further increases in net income during the quarter were due to an unrealized foreign exchange gain resulting from the strengthening of the Canadian dollar on foreign currency sales contracts compared to a loss in the first quarter of 2020, gains on the interest rate non-hedge held within the York Energy joint venture due to increasing interest rates compared with losses in the first quarter of 2020 and reductions in impairment losses compared to the first quarter of 2020 related to the discontinuation of the Genesee 4 and 5 project. Partially offsetting these variances were higher emissions costs at Genesee and higher depreciation expense due to accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine, and the aforementioned commissioning of Cardinal Point Wind and acquisition of Buckthorn Wind.

For the quarter ended December 31, 2020, the Company recorded net income attributable to shareholders of $3 million compared to net income attributable to shareholders of $182 million for the quarter ended December 31, 2019. Decreases in net income were notably driven by accelerated coal compensation revenue recognition and the gain recognized in 2019 as a result of the swap of interests in Genesee 3 and Keephills 3 during the fourth quarter of 2019. Also contributing to reduced net income was the impairment recorded in the fourth quarter of 2020 related to the cancellation of the Genesee 1 and 2 dual-fuel project. Unrealized losses on commodity derivatives and emission credits in the fourth quarter 2020 were $19 million compared with unrealized gains of $28 million in the comparable 2019 period, most notably related to the impact of decreasing forward natural gas prices on net forward purchase contracts during the fourth quarter of 2020. In addition, net income was reduced compared to the fourth quarter of 2019 driven by various operational variances including lower Alberta commercial adjusted EBITDA due largely to higher emissions costs upon changes to the Company's emission compliance strategy in the fourth quarter of 2020 and lower margins earned on natural gas portfolio optimization activities. Arlington Valley also realized lower adjusted EBITDA driven by the revised tolling agreement in effect for 2020. Partially offsetting these operational variances was higher adjusted EBITDA from the acquisition of Buckthorn Wind in the second quarter of 2020 and commencement of operations of Whitla Wind 1 late in the fourth quarter of 2019 and Cardinal Point Wind late in the first quarter of 2020. Net finance expense also increased compared to 2019 as a result of these asset additions. Income tax expense was lower in 2020, driven by the tax effect of the noted variances, primarily the accelerated recognition of deferred government grant revenue upon close of the Genesee 3 and Keephills 3 swap transaction.

For the quarter ended September 30, 2020, the Company recorded net income attributable to shareholders of $108 million compared to net loss attributable to shareholders of $226 million for the quarter ended September 30, 2019. The increase in net income in the third quarter of 2020 was largely due to the pre-tax impairment of $401 million on Keephills 3 recorded upon classification as an asset held for sale in 2019. Further increases in net income in the third quarter of 2020 were driven partly by higher margins earned on Alberta commercial power and natural gas portfolio optimization and higher unrealized gains on commodity derivatives and emission credits, most notably due to the impact of increasing forward prices on natural gas forward purchase contracts during the third quarter of 2020. Higher adjusted EBITDA also resulted from the acquisition of Buckthorn Wind in the second quarter of 2020, and commencement of operations of Whitla Wind 1 late in the fourth quarter of 2019 and Cardinal Point Wind late in the first quarter of 2020. These factors were partially offset by lower adjusted EBITDA at Arlington Valley due to the revised tolling agreement in 2020 and higher net finance expense related to the noted asset additions. In addition, income tax expense in the third quarter of 2020 of $44 million compared to income tax recovery of $66 million for the third quarter of 2019 was primarily due to the recognition of a deferred tax recovery on the impairment of Keephills 3 in 2019.

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 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 and Goreway in the second quarters of 2020 and 2019, respectively, and tax equity financing related to Cardinal Point Wind 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 and Whitla Wind 1 commencing commercial operations in the fourth quarter of 2019 as well as higher impairments related to 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 the fourth quarter of 2019. 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 realized 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 additions 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.

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

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

	Three months ended							
	Jun 30 2021	**Mar 31 2021**	**Dec 31 2020**	**Sep 30 2020**	**Jun 30 2020**	**Mar 31 2020**	**Dec 31 2019**	**Sep 30 2019**
Share price ($/common share)								
High	42.28	38.34	36.47	30.28	29.92	38.88	35.09	31.43
Low	36.22	33.31	29.13	26.57	23.24	20.23	30.13	29.31
Close	40.95	36.40	34.98	29.39	27.98	27.15	34.39	30.68
Volume of shares traded (millions)	21.3	22.9	20.2	21.6	29.5	31.8	21.3	18.2

Outstanding share and partnership unit data

As at July 27, 2021, the Company had 115.127 million common shares, 5 million Cumulative Rate Reset Preference Shares (Series 1), 6 million Cumulative Rate Reset Preference Shares (Series 3), 8 million Cumulative Rate Reset Preference Shares (Series 5), 8 million Cumulative Minimum Rate Reset Preference Shares (Series 7), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 9), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 11) and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares as at July 27, 2021 were 117.515 million. The outstanding special limited voting share is held by EPCOR.

As at July 27, 2021, CPLP had 24.040 million general partnership units outstanding and 89.473 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

ADDITIONAL INFORMATION

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

Condensed Interim Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(Unaudited, in millions of Canadian dollars)
Six months ended June 30, 2021 and 2020

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Six months ended June 30, 2021 and 2020

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Revenues	$ 332	$ 397	$ 828	$ 901
Other income	55	38	113	67
Energy purchases and fuel	(67)	(125)	(216)	(335)
Gross margin	320	310	725	633
Other raw materials and operating charges	(46)	(42)	(82)	(86)
Staff costs and employee benefits expense	(40)	(39)	(91)	(82)
Depreciation and amortization	(135)	(121)	(270)	(241)
Impairment reversal (loss)	2	-	2	(13)
Other administrative expense	(23)	(27)	(51)	(53)
Foreign exchange (loss) gain	(2)	3	(1)	(6)
Operating income	76	84	232	152
Net finance expense	(46)	(49)	(87)	(93)
Income (loss) from joint venture	1	-	7	(7)
Income before tax	31	35	152	52
Income tax expense (note 3)	(14)	(12)	(34)	(29)
Net income	$ 17	$ 23	$ 118	$ 23
Attributable to:				
Non-controlling interests	$ (3)	$ -	$ (5)	$ (2)
Shareholders of the Company	$ 20	$ 23	$ 123	$ 25

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

	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Basic (note 4)	$ 0.05	$ 0.10	$ 0.88	$ (0.02)
Diluted (note 4)	$ 0.05	$ 0.09	$ 0.87	$ (0.02)

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Net income	$ 17	$ 23	$ 118	$ 23
Other comprehensive (loss) income:				
Items that will not be reclassified subsequently to net income:				
Defined benefit plans:				
Actuarial gains[1]	-	-	-	3
Items that are or may be reclassified subsequently to net income:				
Cash flow hedges:				
Unrealized (losses) gains on derivative instruments[2]	(101)	6	(108)	(10)
Reclassification of losses (gains) on derivative instruments to income for the period[3]	52	(18)	88	(7)
Net investment in foreign subsidiaries:				
Unrealized (losses) gains[4]	(5)	(37)	(18)	47
Total items that are or may be reclassified subsequently to net income, net of tax	(54)	(49)	(38)	30
Total other comprehensive (loss) income, net of tax	(54)	(49)	(38)	33
Total comprehensive (loss) income	$ (37)	$ (26)	$ 80	$ 56
Attributable to:				
Non-controlling interests	$ (3)	$ -	$ (5)	$ (2)
Shareholders of the Company	$ (34)	$ (26)	$ 85	$ 58

[1] For the three and six months ended June 30, 2021, net of income tax expense of nil. For the three and six months ended June 30, 2020, net of income tax expense of nil and $1.

[2] For the three and six months ended June 30, 2021, net of income tax recoveries of $32 and $33, respectively. For the three and six months ended June 30, 2020, net of income tax expense of $2 and income tax recovery of $3, respectively.

[3] For the three and six months ended June 30, 2021, net of reclassification of income tax recoveries of $17 and $27, respectively. For the three and six months ended June 30, 2020, net of reclassification of income tax expense of $6 and $3, respectively.

[4] For the three and six months ended June 30, 2021, net of income tax expense of nil. For the three and six months ended June 30, 2020, net of income tax expense of $2 and income tax recovery of $2, respectively.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	June 30, 2021	December 31, 2020
Assets		
Current assets:		
Cash and cash equivalents	$ 138	$ 367
Trade and other receivables	419	499
Inventories	223	220
Derivative financial instruments assets (note 5)	80	71
	860	1,157
Non-current assets:		
Other assets	55	37
Derivative financial instruments assets (note 5)	206	177
Government grant receivable	392	387
Deferred tax assets	23	19
Equity-accounted investments	147	134
Right-of-use assets	120	129
Intangible assets and goodwill	777	773
Property, plant and equipment	6,028	6,098
Total assets	$ 8,608	$ 8,911
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 478	$ 470
Derivative financial instruments liabilities (note 5)	167	91
Loans and borrowings	125	417
Deferred revenue and other liabilities	137	135
Provisions	60	37
	967	1,150
Non-current liabilities:		
Derivative financial instruments liabilities (note 5)	226	212
Loans and borrowings	2,858	3,135
Lease liabilities	135	143
Deferred revenue and other liabilities	242	277
Deferred tax liabilities	600	601
Provisions	389	464
	4,450	4,832
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 6)	3,790	3,465
Deficit	(493)	(474)
Other reserves	(130)	(91)
Deficit and other reserves	(623)	(565)
	3,167	2,900
Non-controlling interests	24	29
Total equity	3,191	2,929
Total liabilities and equity	$ 8,608	$ 8,911

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 6)	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, 2021	$ 3,465	$ (48)	$ (34)	$ (20)	$ 11	$ (474)	$ 2,900	$ 29	$ 2,929
Net income	-	-	-	-	-	123	123	(5)	118
Other comprehensive (loss) income:									
Cash flow derivative hedge losses	-	(141)	-	-	-	-	(141)	-	(141)
Reclassification of losses to net income	-	115	-	-	-	-	115	-	115
Unrealized losses on foreign currency translation	-	-	(18)	-	-	-	(18)	-	(18)
Tax on items recognized directly in equity	-	6	-	-	-	-	6	-	6
Other comprehensive loss	$ -	$ (20)	$ (18)	$ -	$ -	$ -	$ (38)	$ -	$ (38)
Total comprehensive (loss) income	-	(20)	(18)	-	-	123	85	(5)	80
Common share dividends (note 6)	-	-	-	-	-	(114)	(114)	-	(114)
Preferred share dividends (note 6)	-	-	-	-	-	(26)	(26)	-	(26)
Tax on preferred share dividends	-	-	-	-	-	(2)	(2)	-	(2)
Issue of share capital	288	-	-	-	-	-	288	-	288
Share issue costs	(12)	-	-	-	-	-	(12)	-	(12)
Deferred tax on share issue costs	3	-	-	-	-	-	3	-	3
Dividends reinvested	30	-	-	-	-	-	30	-	30
Share options exercised	16	-	-	-	(1)	-	15	-	15
Equity as at June 30, 2021	$ 3,790	$ (68)	$ (52)	$ (20)	$ 10	$ (493)	$ 3,167	$ 24	$ 3,191

[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 6)	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	-	-	-	-	-	25	25	(2)	23
Other comprehensive income (loss):									
Defined benefit plan actuarial gain	-	-	-	4	-	-	4	-	4
Cash flow derivative hedge losses	-	(13)	-	-	-	-	(13)	-	(13)
Reclassification of gains to net income	-	(10)	-	-	-	-	(10)	-	(10)
Unrealized gains on foreign currency translation	-	-	45	-	-	-	45	-	45
Tax on items recognized directly in equity	-	6	2	(1)	-	-	7	-	7
Other comprehensive (loss) income	$ -	$ (17)	$ 47	$ 3	$ -	$ -	$ 33	$ -	$ 33
Total comprehensive (loss) income	-	(17)	47	3	-	25	58	(2)	56
Distributions to non-controlling interests	-	-	-	-	-	-	-	(2)	(2)
Common share dividends (note 6)	-	-	-	-	-	(101)	(101)	-	(101)
Preferred share dividends (note 6)	-	-	-	-	-	(26)	(26)	-	(26)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Common shares purchased	(10)	-	-	-	-	-	(10)	-	(10)
Share options exercised	3	-	-	-	-	-	3	-	3
Equity as at June 30, 2020	$ 3,434	$ (27)	$ 31	$ (12)	$ 11	$ (450)	$ 2,987	$ 33	$ 3,020

[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)

	Six months ended June 30, 2021	2020
Cash flows from operating activities:		
Net income	$ 118	$ 23
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Impairment (reversal) loss	(2)	13
Depreciation and amortization	270	241
Net finance expense	87	93
Fair value changes on commodity derivative instruments and emission credits held for trading	31	27
Foreign exchange losses	1	6
Income tax expense	34	29
(Income) loss from joint venture	(7)	7
Recognition of government grant deferred revenue	(63)	(21)
Tax equity attributes	(47)	(43)
Other items	8	6
Change in fair value of derivative instruments reflected as cash settlement	(11)	(18)
Distributions received from joint venture	5	5
Interest paid	(61)	(62)
Income taxes paid	(5)	(33)
Other cash items	(8)	(26)
Change in non-cash operating working capital	(15)	(53)
Net cash flows from operating activities	335	194
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(313)	(186)
Business acquisition, net of acquired cash	-	(79)
Other cash flows from investing activities	7	1
Change in investing other non-current liabilities	28	-
Change in non-cash investing working capital	37	-
Net cash flow used in investing activities	(241)	(264)
Cash flows used in financing activities:		
Proceeds from issue of loans and borrowings	-	228
Repayment of loans and borrowings	(503)	(158)
Issue costs on loans and borrowings	-	(7)
Repayment of lease liabilities	(3)	(3)
Issue of shares	288	-
Share issue costs	(12)	-
Proceeds from exercise of share options	15	3
Common shares purchased (note 6)	-	(10)
Dividends paid (note 6)	(105)	(127)
Capitalized interest paid	(3)	(3)
Distributions to non-controlling interests	-	(2)
Income taxes paid on preferred share dividends	(5)	(12)
Net cash flows used in financing activities	(328)	(91)
Foreign exchange gain on cash held in a foreign currency	5	1
Net decrease in cash and cash equivalents	(229)	(160)
Cash and cash equivalents at beginning of period	367	248
Cash and cash equivalents at end of period	$ 138	$ 88

See accompanying notes to the condensed interim consolidated financial statements

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

1. Reporting entity:

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

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

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

2. Basis of presentation:

These condensed interim consolidated financial statements have been prepared by management in accordance with International Accounting Standards (IAS) 34, Interim Financial Reporting. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company’s 2020 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 July 29, 2021.

3. Income tax:

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

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	2021	2020
Income before tax	$ 31	$ 35	$ 152	$ 52
Income tax at the statutory rate of 23%[1] (2020 – 25%)	7	9	35	13
Increase (decrease) resulting from:				
Non-deductible (taxable) amounts	5	(2)	4	2
Amounts attributable to non-controlling interests and tax-equity interests	5	4	8	10
Change in unrecognized tax benefits	-	(1)	-	2
Statutory and other rate differences[1]	(4)	1	(14)	1
Other	1	1	1	1
Income tax expense	$ 14	$ 12	$ 34	$ 29

[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. 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. The Alberta corporate tax rate reduction to 8% was considered substantively enacted as at October 20, 2020. Accordingly, the 2020 statutory rate was still 25% as at June 30, 2020 and the 2021 statutory rate is 23%.

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

4. 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 June 30,		Six months ended June 30,	
	2021	2020	2021	2020
Income for the period attributable to shareholders	$ 20	$ 23	$ 123	$ 25
Preferred share dividends[1]	(14)	(13)	(28)	(27)
Earnings (loss) available to common shareholders	$ 6	$ 10	$ 95	$ (2)
Weighted average number of common shares	109,730,029	105,063,540	108,283,457	105,233,460
Basic earnings (loss) per share	$ 0.05	$ 0.10	$ 0.88	$ (0.02)
Weighted average number of common shares	109,730,029	105,063,540	108,283,457	105,233,460
Effect of dilutive share purchase options	767,000	297,118	715,715	-
Diluted weighted average number of common shares	110,497,029	105,360,658	108,999,172	105,233,460
Diluted earnings (loss) per share	$ 0.05	$ 0.09	$ 0.87	$ (0.02)

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

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

5. Derivative financial instruments and hedge accounting:

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

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

	June 30, 2021						
	Energy and emission allowances		Interest rate		Foreign exchange		
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:							
Current	$ 2	$ 73	$ -	$ 5	$ -	$ -	$ 80
Non-current	1	188	13	4	-	-	206
Derivative instruments liabilities:							
Current	(39)	(85)	(27)	-	(10)	(6)	(167)
Non-current	(16)	(152)	(57)	(1)	-	-	(226)
Net fair value	$ (52)	$ 24	$ (71)	$ 8	$ (10)	$ (6)	$ (107)
Net notional buys (sells) (millions):							
Megawatt hours of electricity	(5)	(21)					
Gigajoules of natural gas purchased [1]		143					
Gigajoules of natural gas basis swaps[1]		148					
Number of renewable energy credits		(4)					
Interest rate swaps			$1,391	$ 50			
Forward currency buys (sells) (U.S. dollars)					$ 52	$ (226)	
Range of remaining contract terms in years	0.1 to 4.5	0.1 to 16.5	0.4 to 5.6	1.9	0.1 to 0.5	0.1 to 0.3	

[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)

5. Derivative financial instruments and hedge accounting, continued:

	December 31, 2020					
	Energy and emission allowances		Interest rate		Foreign exchange	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	cash flow hedges	Total
Derivative instruments assets:						
Current	$ 1	$ 65	$ 5	$ -	$ -	$ 71
Non-current	1	173	3	-	-	177
Derivative instruments liabilities:						
Current	(13)	(39)	(23)	(1)	(15)	(91)
Non-current	(18)	(120)	(74)	-	-	(212)
Net fair value	$ (29)	$ 79	$ (89)	$ (1)	$ (15)	$ (55)
Net notional buys (sells) (millions):						
Megawatt hours of electricity	(5)	(20)				
Gigajoules of natural gas purchased[2]		195				
Gigajoules of natural gas basis swaps[2]		197				
Metric tonnes of emission allowances		1				
Number of renewable energy credits		(6)				
Interest rate swaps			$ 1,001	$ 260		
Interest rate swaps (U.S. dollars)			$ 180			
Forward currency buys (U.S. dollars)					$ 94	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 17.0	0.5 to 6.1	0.9 to 1.7	0.3 to 1.0	

[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 2020 annual consolidated financial statements. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

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

	Three months ended June 30, 2021		Three months ended June 30, 2020	
	Unrealized (losses) gains	Realized (losses) gains	Unrealized (losses) gains	Realized gains (losses)
Energy cash flow hedges	$ (42)	$ (67)	$ (4)	$ 26
Energy and emission allowances non-hedges	(22)	2	(13)	10
Interest rate cash flow hedges[3]	(28)	-	(8)	(2)
Interest rate non-hedges	(1)	-	-	-
Foreign exchange cash flow hedges	6	-	(4)	-
Foreign exchange non-hedges	(8)	6	5	(1)

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

5. Derivative financial instruments and hedge accounting, continued:

	Six months ended June 30, 2021		Six months ended June 30, 2020	
	Unrealized (losses) gains	Realized (losses) gains	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (53)	$ (111)	$ 30	$ 12
Energy and emission allowances non-hedges	(32)	(8)	(23)	21
Interest rate cash flow hedges[3]	22	(2)	(46)	(2)
Interest rate non-hedges	9	-	(2)	1
Foreign exchange cash flow hedges	5	-	(7)	-
Foreign exchange non-hedges	(6)	5	(3)	(2)

[3] Includes the settlement of interest rate cash flow hedges of US$180 million in June 2021 for a gain of $14 million of which $12 million is deferred within accumulated other comprehensive loss to be reclassified to net income in future periods within the associated net finance expense pertaining to the hedged note offering.

Realized and unrealized gains and losses relate only to derivative financial instruments. The following realized and unrealized gains and (losses) are included in the Company's consolidated statements of income for the three and six months ended June 30, 2021 and 2020:

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	2021	2020
Revenues	$ (271)	$ 30	$ (434)	$ 41
Energy purchases and fuel	184	(7)	283	(31)
Foreign exchange (loss) gain	(2)	4	(1)	(5)
Net finance expense	(1)	(2)	7	(3)

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 six months ended June 30, 2021, $2 million of gains were realized within net finance expense pertaining to the ineffective portion of hedging derivatives (three and six months ended June 30, 2020 – nil).

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

	June 30, 2021
Within one year	$ (56)
Between one and five years	(16)
After five years	4
	$ (68)

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

6. Share capital:

	Dividends declared							
	For the three months ended June 30,				For the six months ended June 30,			
	2021		2020		2021		2020	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.5125	$ 59	$ 0.4800	$ 50	$ 1.0250	$ 114	$ 0.9600	$101
Preference								
Series 1	0.1638	1	0.1913	1	0.3276	2	0.3825	2
Series 3	0.3408	2	0.3408	2	0.6816	4	0.6816	4
Series 5	0.3274	3	0.3274	3	0.6548	6	0.6548	6
Series 7	0.3750	3	0.3750	3	0.7500	6	0.7500	6
Series 9	0.3594	2	0.3594	2	0.7188	4	0.7188	4
Series 11	0.3594	2	0.3594	2	0.7188	4	0.7188	4

	Dividends paid[2]							
	For the three months ended June 30,				For the six months ended June 30,			
	2021		2020		2021		2020	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[1]	$ 0.5125	$ 55	$ 0.4800	$ 51	$ 1.0250	$ 109	$ 0.9600	$101

[1] For the three months ended June 30, 2021, dividends paid on common shares consist of $40 million paid in cash and $15 million paid through the Company's dividend reinvestment plan as common shares issued. For the six months ended June 30, 2021, dividends paid on common shares consist of $79 million paid in cash and $30 million paid through the Company's dividend reinvestment plan as common shares issued.

For the three and six months ended June 30, 2020, all common dividends were paid in cash. The Company reinstated its dividend reinvestment plan for its common shares effective for the September 30, 2020 dividend.

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

During the three and six months ended June 30, 2021, the Company did not purchase and cancel any of its outstanding common shares under its Toronto Stock Exchange approved normal course issuer bid (three and six months ended June 30, 2020 – nil and 461,832 common shares at an average exercise price of $22.67 per share for $10 million, respectively).

In June 2021, the Company completed a public offering of 7,480,750 common shares (inclusive of the full exercise of a 975,750 common share over-allotment option) at an issue price of $38.45 per common share for total gross proceeds of approximately $288 million less issue costs of $12 million.

7. Financial instruments

Fair values

Details of the fair values of the Company's derivative instruments are described in note 5.

The Company's other short-term financial instruments are classified and measured at amortized cost, consistent with the methodologies described in the Company's 2020 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.

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

7. Financial instruments, continued:

Fair values, continued

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 2020 annual consolidated financial statements. The carrying amount and fair value of the Company's other financial instruments, which are all classified and subsequently measured at amortized cost, are summarized as follows:

		June 30, 2021		December 31, 2020	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets[1]					
Government grant receivable	Level 2	$ 448	$ 445	$ 441	$ 448
Financial liabilities[1]					
Loans and borrowings	Level 2	$ 2,983	$ 3,192	$ 3,552	$ 3,838

[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, 2020.

The fair value measurement of a financial instrument is included in only one of the three levels described in the Company's 2020 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 six months ended June 30, 2021 and the year ended December 31, 2020 are disclosed below within the continuity of Level 3 balances.

The table below presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated statements of financial position, classified using the fair value hierarchy described in the Company's 2020 annual consolidated financial statements.

	June 30, 2021			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 278	$ 8	$ 286
Derivative financial instruments liabilities	-	(343)	(50)	(393)

	December 31, 2020			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 182	$ 66	$ 248
Derivative financial instruments liabilities	-	(272)	(31)	(303)

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

7. Financial instruments, continued:

Fair value hierarchy, continued

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. Anticipated generation continues to be forecasted based on internal modelling. Accordingly, the financial instrument is classified as Level 3.

The Company has a 20-year revenue offtake swap agreement for Buckthorn Wind 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 5 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 June 30, 2021 and December 31, 2020, the Company holds contracts for the sale of renewable energy credits (RECs) for which pricing beyond two years is not readily observable and the contracts are therefore classified in Level 3 of the hierarchy.

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

	June 30, 2021	December 31, 2020
REC pricing (per certificate) – Solar	$201.37 to $378.33	$206.86 to $384.76
REC pricing (per certificate) – Wind	$2.30 to $4.87	$1.99
Forward power pricing (per MWh) - Wind	$20.51 to $100.90	$19.32 to $79.17
Monthly generation (MWh) – Bloom Wind	49,721 to 71,629	51,100 to 70,160
Monthly generation (MWh) – Buckthorn Wind	11,365 to 21,736	11,365 to 21,736

Valuation process applied to Level 3

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

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

	June 30, 2021	December 31, 2020
REC pricing – Solar[2]	$ 1	$ 1
REC pricing – Wind[3]	4	4
Forward power pricing – Wind[3]	14	15
Generation – Wind[4]	11	7

[2] Reflects the increase or decrease to fair value calculated using a $10 per unit decrease or increase in the input.

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

[4] Reflects the increase or decrease to fair value calculated using a 10% decrease or increase in the input.

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

7. Financial instruments, continued:

Fair value hierarchy, continued

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:

	June 30, 2021	December 31, 2020
As at January 1[5]	$ 35	$ 41
Acquired with Buckthorn Wind	-	44
Unrealized and realized losses included in net income[6]	(72)	(41)
Settlements[7]	(4)	(4)
Transfers[8]	-	(3)
Foreign exchange losses	(1)	(2)
As at end of period	$ (42)	$ 35
Total unrealized and realized losses for the period included in net income[6]	$ (72)	$ (41)

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

[6] Recorded in revenues.

[7] Relates to settlement of financial derivative instruments.

[8] 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.

8. Commitments, contingencies and other:

Island Generation Electricity Purchase Agreement

BC Hydro published their draft Integrated Resource Plan (IRP) in June 2021 which references that BC Hydro is not currently intending to renew the long-term Electricity Purchase Agreement (EPA) for the Company's Island Generation facility at Campbell River on Vancouver Island, which expires in April 2022. The Company continues to believe the Island Generation facility is needed to ensure secure and reliable electricity supply for homes and businesses on Vancouver Island and in Metro Vancouver and will actively participate in BC Hydro's consultation process and the following regulatory process. BC Hydro will be incorporating feedback into its final IRP which is due to be filed with the BC Utilities Commission by the end of 2021.

The current carrying amount of the property, plant and equipment of Island Generation at June 30, 2021 is $101 million.

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

8. Commitments, contingencies and other, continued:

Buckthorn Wind settlement dispute

Following the severe weather events during the February 9 to 20, 2021 period, the Company settled the offtake and commodity swaps for Buckthorn Wind for the noted time period based on the pricing dictated in the respective agreements. However, Buckthorn Wind's counterparty is contesting the settlement, arguing that settlement should have been based upon a different reference price. Historically these two prices have been similar, but as a result of the recent extreme weather, the Company became aware of a divergence in these prices during scarcity events. Both parties have invoked dispute-resolution procedures and the Company has initiated litigation. Based on the contract terms of the offtake and commodity swaps, the Company considers the probability of ultimate settlement using the reference price advocated by the counterparty as being unlikely. In the event that the dispute is resolved unfavorably to the Company, the net exposure to the Company's revenues would be a reduction of up to approximately $18 million (US$15 million).

9. 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 within each geographic area are:

	Three months ended June 30, 2021				Three months ended June 30, 2020			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues – external[1]	$ 392	$ (60)	$ -	$ 332	$ 333	$ 64	$ -	$ 397
Revenues – inter-area	8	-	(8)	-	-	(4)	4	-
Other income	33	22	-	55	13	25	-	38
Total revenues and other income	$ 433	$ (38)	$ (8)	$ 387	$ 346	$ 85	$ 4	$ 435

	Six months ended June 30, 2021				Six months ended June 30, 2020			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues – external[1]	$ 844	$ (16)	$ -	$ 828	$ 749	$ 152	$ -	$ 901
Revenues – inter-area	13	-	(13)	-	7	(3)	(4)	-
Other income	66	47	-	113	25	42	-	67
Total revenues and other income	$ 923	$ 31	$ (13)	$ 941	$ 781	$ 191	$ (4)	$ 968

[1] Revenues from external sources includes realized and unrealized gains and losses from derivative financial instruments.

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

9. Segment information, continued:

	As at June 30, 2021			As at December 31, 2020		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 4,417	$ 1,611	$ 6,028	$ 4,417	$ 1,681	$ 6,098
Right-of-use assets	55	65	120	60	69	129
Intangible assets and goodwill	656	121	777	637	136	773
Other assets	55	-	55	37	-	37
	$ 5,183	$ 1,797	$ 6,980	$ 5,151	$ 1,886	$ 7,037

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

	Three months ended June 30, 2021						
	Alberta Commercial[2]	Western Canada Contracted[3]	Ontario Contracted[3]	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 416	$ 17	$ 65	$ 36	$ 534	$ (210)	$ 324
Emission credit revenues	6	-	-	-	6	2	8
Total revenues[1]	$ 422	$ 17	$ 65	$ 36	$ 540	(208)	$ 332

	Six months ended June 30, 2021						
	Alberta Commercial[2]	Western Canada Contracted[3]	Ontario Contracted[3]	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 806	$ 44	$ 140	$ 120	$ 1,110	$ (293)	$ 817
Emission credit revenues	13	-	-	2	15	(4)	11
Total revenues[1]	$ 819	$ 44	$ 140	$ 122	$ 1,125	(297)	$ 828

	Three months ended June 30, 2020						
	Alberta Commercial	Western Canada Contracted[3]	Ontario Contracted[3]	U.S. Contracted	Total from contracts with customers	Other sources[2]	Total
Energy revenues	$ 96	$ 18	$ 70	$ 53	$ 237	$ 151	$ 388
Emission credit revenues	7	-	-	2	9	-	9
Total revenues[1]	$ 103	$ 18	$ 70	$ 55	$ 246	$ 151	$ 397

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

9. Segment information, continued:

	Six months ended June 30, 2020						
	Alberta Commercial	Western Canada Contracted[3]	Ontario Contracted[3]	U.S. Contracted	Total from contracts with customers	Other sources[2]	Total
Energy revenues	$ 293	$ 46	$ 140	$ 107	$ 586	$ 302	$ 888
Emission credit revenues	14	-	-	4	18	(5)	13
Total revenues[1]	$ 307	$ 46	$ 140	$ 111	$ 604	$ 297	$ 901

[1] Included within trade and other receivables, as at June 30, 2021, were amounts related to contracts with customers of $257 million (2020 - $97 million).

[2] The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, commencing January 1, 2021, electricity from Genesee 1 and 2 is sold into the energy market on a merchant or non-contracted basis and presented within Alberta commercial facilities. Comparative periods reflect energy sold on a contracted basis and accounted for under IFRS 16 – *Leases* which was therefore excluded from the scope of IFRS 15 – *Revenue from Contracts with Customers* and disclosed as revenues from other sources.

[3] During the first quarter of 2021, management has reviewed its facility groupings as a result of the change in classification of Genesee 1 and 2 as well as recent internal organizational changes. To best reflect how the Company operates, commencing January 1, 2021, the British Columbia and Alberta contracted facilities will be reported together as Western Canada contracted facilities with the Ontario contracted facilities in a separate grouping. Comparative figures have been reclassified to conform to the current period's presentation.

10. Subsequent events:

Dividend increase

On July 29, 2021, the Company's Board of Directors approved an increase of 6.8% to $2.19 in the annual dividend per common share effective for the third quarter of 2021.

US$150 million private placement of senior notes

On July 20, 2021, the Company executed a US$150 million private placement of senior notes. The 12-year senior notes will bear a coupon rate of 3.24% and mature on October 28, 2033. Subject to satisfying closing conditions, the transaction is expected to fund on October 28, 2021.

Sustainability-linked credit facilities

On July 14, 2021, the Company announced the extension, amendment and transition of its existing committed credit facilities to sustainability-linked credit facilities (SLCs). The 5-year commitment to SLCs extends the Company's existing $1 billion of unsecured credit facilities, which include a $700 million syndicated credit facility and an unsecured club credit facility of $300 million, to July 2026. The SLCs are structured with one key performance indicator with annual sustainability performance targets aligned to one of Capital Power's publicly stated sustainability targets: to reduce Scope 1 CO_2 emission intensity by 65% by 2030 from 2005 levels. The SLCs include terms that reduce or increase borrowing costs as the annual targets are met or missed.

11. Comparative figures:

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