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Capital Power reports strong second quarter results, increases its 2022 financial guidance, and announces a 6% common share dividend increase

EDMONTON, Alberta – August 2, 2022 – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended June 30, 2022.

Financial Highlights

- Generated net cash flows from operating activities of $108 million and adjusted funds from operations (AFFO) of $180 million
- Generated net income of $77 million and adjusted EBITDA of $319 million
- Increased 2022 annual financial guidance for adjusted EBITDA to $1,240 million to $1,280 million (original guidance of $1,110 million to $1,160 million) and AFFO to $700 million to $740 million (original guidance of $580 million to $630 million)
- Increased the annual common share dividend by 6% to $2.32 per year representing the ninth consecutive annual increase

Strategic Highlights

- Announced the acquisition of the Midland Cogeneration Venture (Midland Cogen) facility, the largest gas-fired cogeneration facility in North America, where Capital Power and Manulife Investment Management will each own a 50% interest for a total purchase price of $1,163 million (US$894 million)
- Increased annual dividend growth guidance to 6% through to 2025 from the previous 5%
- Partnered with Mitsubishi Heavy Industries Group and Kiewit Energy Group on a front-end engineering and design (FEED) study for the Genesee carbon capture and sequestration (CCS) Project advancing the commercial application of CCS technology at its Genesee Generating Station in Alberta
- Executed a 4.5-year contract renewal for the Island Generation facility in British Columbia

“Second quarter financial results continue to exceed management’s expectations,” said Brian Vaasjo, President and CEO of Capital Power. “Higher generation and strong Alberta power prices averaging $106 per megawatt hour along with outstanding performance across the fleet led to exceptional performance in the first half of the year. Based on this performance and the positive outlook for the remainder of the year, we have increased our 2022 financial guidance with revised guidance ranges significantly exceeding the top end of our original targets.”

“We continue to execute on our strategy of acquiring mid-life contracted natural gas assets that are strategically positioned within their power markets by announcing an agreement to acquire a 50% interest in the Midland Cogen facility with our partner, Manulife Investment Management,” continued Mr. Vaasjo. “The transaction provides immediate AFFO accretion and is supported by highly contracted cash flows to 2030 and 2035. Located in Michigan, it is the largest gas-fired cogeneration facility in North America and combined with its excellent reliability history and operating flexibility, Midland Cogen is a critical asset to support grid reliability during the transition to renewables and is extremely well-positioned for recontracting beyond 2030.”

“I am pleased to announce the Board of Directors has approved a 6% per common share dividend increase effective for the third quarter 2022 dividend payment. As previously announced, we increased our annual dividend guidance to 2025, from 5% to 6% on the strength of contracted cash flows from the acquisition of the Midland Cogen facility. The growing dividend is forecasted to be below our long-term AFFO payout ratio target of 45% to 55% through 2025,” stated Mr. Vaasjo.

Operational and Financial Highlights[1]

(unaudited, $ millions, except per share amounts)	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Electricity generation (Gigawatt hours)	6,638	4,975	13,531	10,605
Generation facility availability	92%	84%	93%	90%
Revenues and other income	713	387	1,214	941
Adjusted EBITDA [2]	319	241	667	544
Net income [3]	77	17	196	118
Net income attributable to shareholders of the Company	80	20	202	123
Basic earnings per share ($)	0.59	0.05	1.56	0.88
Diluted earnings per share ($)	0.59	0.05	1.55	0.87
Normalized earnings attributable to common shareholders [2]	88	35	196	103
Normalized earnings per share ($) [2]	0.76	0.32	1.69	0.95
Net cash flows from operating activities	108	129	523	335
Adjusted funds from operations [2]	180	91	380	250
Adjusted funds from operations per share ($) [2]	1.55	0.83	3.27	2.31
Purchase of property, plant and equipment and other assets	147	151	279	248
Dividends per common share, declared ($)	0.5475	0.5125	1.0950	1.0250

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, 2022.

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 and adjusted funds from operations (AFFO) are used as non-GAAP financial measures by the Company. The Company also uses normalized earnings per share and AFFO per share which are non-GAAP ratios. These measures and ratios 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 and Ratios.

3 Includes depreciation and amortization for the three months ended June 30, 2022 and 2021 of $139 million and $132 million, respectively, and for the six months ended June 30, 2022 and 2021 of $281 million and $269 million, respectively. Forecasted depreciation and amortization for the remainder of 2022 is $135 million and $137 million for the third and fourth quarters, respectively.

Significant Events

Advancement of carbon capture project at Genesee

On June 27, 2022, the Company announced it had partnered with Mitsubishi Heavy Industries Group and Kiewit Energy Group on a FEED study for the Genesee CCS Project advancing the commercial application of CCS technology at its Genesee Generating Station in Alberta.

Appointment to the Board of Directors

Effective June 1, 2022, Gary Bosgoed was appointed to the Company's Board of Directors. With this appointment, Capital Power's Board of Directors consists of 10 directors, including 40% women and 30% with diversity beyond gender.

Executed 4.5-year contract renewal for Island Generation

On May 16, 2022, the Company announced the execution of a 4.5-year Electricity Purchase Agreement (EPA) through October 2026 for its Island Generation facility with BC Hydro. The EPA is subject to regulatory approval by the British Columbia Utilities Commission. The terms of the 4.5-year EPA are consistent with the Company's expectations when it recorded a $52 million impairment in 2021.

Subsequent Events

Dividend increase

On July 29, 2022, the Company's Board of Directors approved an increase of 6% in the annual dividend for holders of its common shares, from $2.19 per common share to $2.32 per common share. This increased common share dividend will commence with the third quarter 2022 quarterly dividend payment on October 31, 2022 to shareholders of record at the close of business on September 30, 2022.

Acquisition of Midland Cogeneration Venture

On July 12, 2022, Capital Power announced it had partnered with Manulife Investment Management on behalf of the Manulife Infrastructure Fund II and its affiliates to acquire 100% of the interests in MCV Holding Company, which owns Midland Cogen, a 1,633 MW natural gas combined-cycle cogeneration facility. Midland Cogen is being acquired from OMERS Infrastructure Management Inc and its co-investors for a total purchase price of $1,163 million (US$894 million), including the assumption of $678 million (US$521 million) of project level debt. The transaction is expected to close in the third quarter of 2022, subject to regulatory approvals and other customary closing conditions.

Located in Michigan, Midland Cogen, is the largest gas-fired cogeneration facility in North America, is a critical asset to support grid reliability during the transition to renewables and is well-positioned, given anticipated market conditions, for recontracting beyond 2030. Capital Power and Manulife Investment Management will each own a 50% interest in MCV Holding Company and will each contribute approximately $242 million (US$186 million) subject to working capital and other closing adjustments. Capital Power will finance its share of the transaction using cash on hand and its existing credit facilities. Capital Power will be responsible for operations and maintenance and asset management for which it will receive an annual management fee.

The acquisition supports Capital Power's strategy of acquiring mid-life contracted natural gas assets that are strategically positioned within their power markets. Acquisition highlights include:

- Capital Power's share of expected average adjusted EBITDA of US$59 million per year (ranging from US$85 million in 2023 and declining to US$45 million in 2027).
- based on the expected financing, the 5-year average accretion for Capital Power's AFFO is expected to be US$0.30 per share, reflecting a 7% increase, or an average AFFO of US$35 million per year during the years 2023-2027.
- power purchase agreement with Consumers Energy (rated Baa1/A-/A-) for 1,240 MW of capacity to 2030
- steam and electricity purchase agreement with Corteva Agriscience (rated NA/A-/A) and Dow Silicones (rated Baa2/BBB/BBB+) to 2035.
- approximately 15% (243 MW) of uncontracted capacity is available to sell into the MISO Zone 7 market
- located on 1,200 acres leased from Consumers Energy. Current layout and additional space allow for additional turbines, battery installation or a hybrid opportunity.

Analyst conference call and webcast

Capital Power will be hosting a conference call and live webcast with analysts on August 2, 2022 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 and Ratios

The Company uses (i) adjusted EBITDA, (ii) AFFO, and (iii) normalized earnings attributable to common shareholders as financial performance measures.

The Company also uses AFFO per share and normalized earnings per share as performance measures. These measures are non-GAAP ratios determined by applying AFFO and normalized earnings attributable to common shareholders, respectively, to the weighted average number of common shares used in the calculation of basic and diluted earnings per share.

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 2022	**Mar 2022**	**Dec 2021**	**Sep 2021**	**Jun 2021**	**Mar 2021**	**Dec 2020**	**Sep 2020**
Revenues and other income	713	501	672	377	387	554	516	453
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(429)	(178)	(506)	(162)	(176)	(264)	(321)	(144)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	28	18	123	66	24	7	19	(31)
Adjusted EBITDA from joint venture [1]	7	7	5	5	6	6	6	6
Adjusted EBITDA	**319**	**348**	**294**	**286**	**241**	**303**	**220**	**284**
Depreciation and amortization	(139)	(142)	(137)	(133)	(132)	(137)	(122)	(115)
Unrealized changes in fair value of commodity derivatives and emission credits	(28)	(18)	(123)	(66)	(24)	(7)	(19)	31
Impairment (losses) reversals	-	-	(52)	(8)	2	-	(13)	-
(Losses) gains on acquisition and disposal transactions	(1)	-	6	31	(3)	2	-	-
Foreign exchange (loss) gain	(7)	1	(1)	(7)	(2)	1	5	1
Net finance expense	(35)	(37)	(44)	(43)	(46)	(41)	(57)	(47)
Finance expense and depreciation expense from joint venture [1]	(1)	-	(4)	(4)	(5)	-	(4)	(4)
Income tax expense	(31)	(33)	(8)	(18)	(14)	(20)	(9)	(44)
Net income (loss)	**77**	**119**	**(69)**	**38**	**17**	**101**	**1**	**106**
Net income (loss) attributable to:								
Non-controlling interests	(3)	(3)	(4)	(2)	(3)	(2)	(2)	(2)
Shareholders of the Company	80	122	(65)	40	20	103	3	108
Net income (loss)	**77**	**119**	**(69)**	**38**	**17**	**101**	**1**	**106**

[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 and AFFO per share are measures 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 off-coal compensation that will be received annually,
- remove the tax equity financing project investors' shares of AFFO associated with assets under tax equity financing structures so only the Company's share is reflected in the overall metric,
- deduct sustaining capital expenditures and preferred share dividends,
- 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 amounts in the period each tranche is paid by the Company.

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	
	2022	**2021**	**2022**	**2021**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**108**	**129**	**523**	**335**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	16	20	54	61
Realized gains on settlement of interest rate derivatives	-	(12)	-	(12)
Change in fair value of derivatives reflected as cash settlement	52	7	45	11
Distributions received from joint venture	(2)	(2)	(2)	(5)
Miscellaneous financing charges paid [1]	2	2	4	3
Income taxes paid	5	-	17	5
Change in non-cash operating working capital	75	35	(105)	15
	148	50	13	78
Net finance expense [2]	(29)	(29)	(60)	(64)
Current income tax expense [3]	(9)	(13)	(24)	(16)
Sustaining capital expenditures [4]	(30)	(29)	(55)	(47)
Preferred share dividends paid	(10)	(13)	(20)	(26)
Remove tax equity interests' respective shares of adjusted funds from operations	(4)	(2)	(8)	(6)
Adjusted funds from operations from joint venture	6	5	11	9
Line Loss Rule Proceeding [5]	-	(7)	-	(13)
Adjusted funds from operations	**180**	**91**	**380**	**250**
Weighted average number of common shares outstanding (millions)	**116.4**	**109.7**	**116.3**	**108.3**
Adjusted funds from operations per share ($)	**1.55**	**0.83**	**3.27**	**2.31**

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.

4 Includes sustaining capital expenditures net of partner contributions of $1 million and $2 million for the three and six months ended June 30, 2022 and 2021, respectively, compared with $2 million and $7 million for the three and six months ended June 30, 2021.

5 Consistent with the Company's definition of AFFO described above pertaining to the LLR Proceeding, AFFO for the three months and six months ended June 30, 2021 is impacted only by the Company's net obligations related to the 2006-2009 and 2010–2013 invoice tranches.

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 attributable to common shareholders and normalized earnings per share are based on net income (loss) attributable to shareholders of the Company 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 2022	Mar 2022	Dec 2021	Sep 2021	Jun 2021	Mar 2021	Dec 2020	Sep 2020
Basic earnings (loss) per share ($)	**0.59**	**0.96**	**(0.67)**	**0.23**	**0.05**	**0.83**	**(0.09)**	**0.89**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)	**80**	**122**	**(65)**	**40**	**20**	**103**	**3**	**108**
Preferred share dividends including Part VI.1 tax	(11)	(10)	(13)	(13)	(14)	(14)	(13)	(14)
Earnings (loss) attributable to common shareholders	69	112	(78)	27	6	89	(10)	94
Unrealized changes in fair value of derivatives [1]	14	(2)	83	48	25	(10)	12	(28)
Genesee 2 forced outage	-	-	(5)	(12)	-	-	-	-
Provision for contingency	-	-	-	(6)	6	-	-	-
Impairment losses (reversal)	-	-	41	6	(2)	-	10	-
Reduction in applicable jurisdictional tax rates	-	-	10	-	-	(10)	-	-
Provision for Line Loss Rule Proceeding	-	-	-	-	-	(1)	1	-
Other	5	(2)	4	-	-	-	-	3
Normalized earnings attributable to common shareholders	**88**	**108**	**55**	**63**	**35**	**68**	**13**	**69**
Weighted average number of common shares outstanding (millions)	116.4	116.2	116.0	115.5	109.7	106.8	105.7	105.1
Normalized earnings per share ($)	**0.76**	**0.93**	**0.47**	**0.55**	**0.32**	**0.64**	**0.12**	**0.66**

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

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 2022 AFFO and adjusted EBITDA guidance, (ii) expectations pertaining to the financial impacts of the acquisition of Midland Cogen (see Subsequent Events), including the impacts to AFFO, AFFO per share and adjusted EBITDA, transaction close timing, financing plans, positioning for potential re-contracting following contract expiries in 2030 and 2035, and future site development opportunities, (iii) the timing of the investment decision for the Company's potential CCS project, and (iv) forecasted depreciation for the remainder of 2022.

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 potential re-contracting of facilities) and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations and (v) effective tax rates.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are: (i) changes in electricity, 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 both the Company's Management's Discussion and Analysis for the six months ended June 30, 2022, prepared as of July 29, 2022 and the Company's 2021 Integrated Annual Report, prepared as of February 23, 2022, 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 approximately 6,600 MW of power generation capacity at 27 facilities across North America. Projects in advanced development include approximately 385 MW of owned renewable generation capacity in North Carolina and Alberta and 512 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, 2022, 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, 2022, 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, 2021 (the 2021 Integrated Annual Report), the Annual Information Form of Capital Power Corporation dated February 24, 2022, and the cautionary statements regarding forward-looking information which begin on page 9.

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, 2022 and June 30, 2021 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, 2022.

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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 2022 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 with the addition of battery storage and conversion of Genesee 3, 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, dividends and distributions;
- the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings;
- expectations pertaining to the financial impacts of the acquisition of Midland Cogeneration Venture (Midland Cogen) (see Subsequent Events), including the impacts to AFFO, AFFO per share and adjusted EBITDA, transaction close timing, financing plans, positioning for potential re-contracting following contract expiries in 2030 and 2035, and future site development opportunities;
- the timing of, funding of and costs of existing, planned and potential development projects and acquisitions (including phase 2 of Halkirk Wind, the repowering of Genesee 1 and 2 (including being hydrogen ready and battery storage), 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);
- market and regulation designs and the impact thereof on the Company's core markets; and
- the impacts of climate change and the Russia-Ukraine conflict.

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

- electricity and other energy prices and carbon prices;
- performance;
- business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects;
- status of and impact of policy, legislation and regulations;
- effective tax rates;
- the development and performance of technology;
- foreign exchange rates;
- matters relating to the LLR Proceeding, including the timing and recovery from appropriate parties; and
- other matters discussed under the Performance Overview, Outlook and Risks and Risk Management sections.

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

- changes in electricity, 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;
- disruptions, or price volatility within the Company's supply chains;
- 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, including inflation;
- 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 2021 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 approximately 6,600 megawatts (MW) of power generation capacity at 27 facilities across North America. Projects in advanced development include approximately 385 MW of owned renewable generation capacity in North Carolina and Alberta and 512 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 and pathway towards net carbon neutral remains unchanged from that disclosed in its 2021 Integrated Annual Report.

PERFORMANCE OVERVIEW

The Company measures our operational and financial performance in relation to our corporate strategy and progress toward our sustainability objectives 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

Facility availability average	Sustaining capital expenditures [1] (in millions)
93%	$55
Actual results[2]	Actual results[2]
2022 target[3] of 93% or greater	2022 target[3] of $105 to $115

[1] Includes sustaining capital expenditures net of joint venture contributions of $2 million.
[2] For the six months ended June 30, 2022.
[3] The targets are consistent with those presented at the Company's Investor Day in December 2021 and have not been revised to reflect the expected impact of the acquisition of Midland Cogen for the periods subsequent to the close of the transaction expected in the third quarter of 2022 (see Subsequent Events).

The Company's facility availability averaged 93% which reflected planned outages at Arlington Valley, Genesee, Goreway and Clover Bar Energy Centre. Unplanned outages also occurred at Genesee, Decatur and Clover Bar Energy Centre.

Sustaining capital expenditures for the six months ended June 30, 2022 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 above the target range driven by a combination of increased work now planned for the remainder of 2022 and period to period timing of work.

Disciplined growth

Performance measure	2022 target	Status at June 30, 2022
Repowering of Genesee 1 and 2	Continued progress with anticipated in-service date in late 2023 for the repowered Genesee Unit 1 and 2024 for Genesee Unit 2.	Construction is underway and the anticipated in-service dates remain consistent with target.
Renewable projects:	Target completion dates on time and on budget for 2022 projects and progress on the development of 2024 projects to be on track with budget and completion dates:	Enchant Solar is expected to exceed the current budget, but remains on track with its targeted in-service date. The Company continues to develop its other renewable projects.
Strathmore Solar (Alberta)	Early 2022	Completed on schedule (see Significant Events).
Enchant Solar (Alberta)	Fourth quarter of 2022	
Bear Branch Solar (North Carolina)	Fourth quarter of 2024	
Hornet Solar (North Carolina)	Fourth quarter of 2024	
Hunter's Cove Solar (North Carolina)	Fourth quarter of 2024	
Phase 2 of Halkirk Wind (Alberta)	Fourth quarter of 2024	
Other growth	$500 million of committed capital	Subsequent to June 30, 2022, the Company exceeded its target for committed capital with its announcement to acquire Midland Cogen (see Subsequent Events). The Company continues to seek committed growth capital opportunities in the remainder of 2022.

Financial stability and strength

Adjusted funds from operations [1] (in millions)

$380

Actual results[2]
Updated guidance[3] of $700 to $740
2022 target of $580 to $630

Adjusted EBITDA [1] (in millions)

$667

Actual results[2]
Updated guidance[3] of $1,240 to $1,280
2022 target of $1,110 to $1,160

1 Adjusted funds from operations and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures and Ratios.
2 For the six months ended June 30, 2022.
3 Based on the Company's year-to-date results, expectations for the remainder of the year and the expected results from the acquisition of Midland Cogen facility (see Subsequent Events) for the periods subsequent to the close of the transaction in the third quarter of 2022, the Company provided updated guidance for 2022 (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 our Investor Day held in December 2021, the Company provided financial guidance for 2022 AFFO in the range of $580 million to $630 million and 2022 adjusted EBITDA in the range of $1,110 million to $1,160 million (see Non-GAAP Financial Measures and Ratios). Based on the actual results for the first half of 2022, the Company's forecast for the back half of the year, and the addition of the Midland Cogen facility (see Subsequent Events) the projected range for 2022 AFFO and adjusted EBITDA has been increased to $700 million to $740 million and $1,240 million to $1,280 million, respectively. In addition to the Midland Cogen acquisition, which is anticipated to close in the third quarter of 2022 (see Subsequent Events), the increased guidance ranges are driven most notably by the impact of higher Alberta power prices and generation along with strong performance across the facilities in the first half of 2022 and expectations for the back half of 2022 considering the Company's existing Alberta portfolio position for the remainder of the year as well as strong forward pricing for our remaining Alberta generation.

During the first half of 2022, significant progress has been made on carbon capture, utilization and storage (CCUS). The Company completed a preliminary front-end engineering and design (FEED) study that updated various technical and cost parameters associated with the carbon capture facilities and FEED study activities are proceeding (see Significant Events). With respect to the CCUS policy framework, the Enbridge Open Access Wabamun Carbon Hub, which would provide transportation and sequestration services for the Genesee carbon capture and sequestration (CCS) Project among other projects, was awarded the right to pursue development of a carbon hub as part of the Government of Alberta's CCUS Hub process. As part of Budget 2022 tabled on April 7, 2022, the Government of Canada proposed a refundable investment tax credit (ITC) for investment in CCUS projects (see Regulatory Matters). Separately, as part of the 2030 Emissions Reduction Plan released on March 29, 2022, the Federal Government advised of its intention to explore measures that could provide greater certainty regarding carbon pricing in order to de-risk private sector low-carbon investments. These measures will help support the Company's proposed Genesee CCS Project and other carbon capture and conversion related initiatives, though the specific implications of these initiatives are being assessed.

Priorities for the Company for the remainder of 2022 include progressing our sustainability targets through:

- Continued progression on the repowering of Genesee 1 and 2 and conversion of Genesee 3,
- Further advancement of CCUS and carbon conversion technologies at the Genesee facility,
- Ongoing development of renewable projects, and
- Strategic acquisitions of renewable and natural gas assets.

Given the Company's announcement to acquire Midland Cogen (see Subsequent Events), finalizing the integration of Midland Cogen will be a priority during the remainder of 2022.

In 2022, Capital Power's availability target of 93% or greater reflects major scheduled maintenance outages for Genesee 1 and 3, Clover Bar Energy Centre and Goreway. Scheduled outages for 2021 covered Genesee 2, Decatur Energy and Shepard.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2023, 2024 and 2025 (all at June 30, 2022) were:

Alberta commercial portfolio positions and power prices	Full year 2023	Full year 2024	Full year 2025
Percentage of baseload generation sold forward [1]	70%	45%	27%
Contracted price [2]	High-$60	Low-$60	Low-$60
Forward Alberta pool prices	$95	$69	$65
Percentage of natural gas requirements purchased forward [3]	over 80%	over 80%	over 50%
Contracted Alberta natural gas price per GJ [2,4]	$2.00-$2.50	$2.00-$2.50	$2.00-$2.50
Forward Alberta natural gas prices per GJ	$4.37	$4.10	$4.08

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.

3 Based on forecasted natural gas requirements from the Company's most recent forecast. Actual fuel requirements for Alberta facilities may differ significantly as a result of dispatch decisions.

4 The Company presents average contracted Alberta natural gas prices based on $0.50 per GJ bands.

The 2022 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. 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 our Investor Day held in December 2021, the Company confirmed 5% annual dividend growth guidance for 2022 and announced the extension of our 5% annual dividend growth guidance to 2025. In July 2022, on the strength of anticipated contracted cash flows from the Midland Cogen acquisition (see Subsequent Events), the Company announced an increase of annual dividend growth guidance to 6% through 2025 from the previous 5%. Each annual increase is premised on the assumptions listed under Forward-Looking Information and subject to approval by the Board of Directors of Capital Power at the time of the increase.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding. It is expected that, outside of new growth opportunities beyond currently announced projects, no additional common share equity will be required in 2022 to fund our current growth projects.

NON-GAAP FINANCIAL MEASURES AND RATIOS

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, and (iii) normalized earnings attributable to common shareholders as financial performance measures.

The Company also uses AFFO per share and normalized earnings per share as performance measures. These measures are non-GAAP ratios determined by applying AFFO and normalized earnings attributable to common shareholders, respectively, to the weighted average number of common shares used in the calculation of basic and diluted earnings per share.

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, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emission credits 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 2022	**Mar 2022**	**Dec 2021**	**Sep 2021**	**Jun 2021**	**Mar 2021**	**Dec 2020**	**Sep 2020**
Revenues and other income	713	501	672	377	387	554	516	453
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(429)	(178)	(506)	(162)	(176)	(264)	(321)	(144)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	28	18	123	66	24	7	19	(31)
Adjusted EBITDA from joint venture [1]	7	7	5	5	6	6	6	6
Adjusted EBITDA	**319**	**348**	**294**	**286**	**241**	**303**	**220**	**284**
Depreciation and amortization	(139)	(142)	(137)	(133)	(132)	(137)	(122)	(115)
Unrealized changes in fair value of commodity derivatives and emission credits	(28)	(18)	(123)	(66)	(24)	(7)	(19)	31
Impairment (losses) reversals	-	-	(52)	(8)	2	-	(13)	-
(Losses) gains on acquisition and disposal transactions	(1)	-	6	31	(3)	2	-	-
Foreign exchange (loss) gain	(7)	1	(1)	(7)	(2)	1	5	1
Net finance expense	(35)	(37)	(44)	(43)	(46)	(41)	(57)	(47)
Finance expense and depreciation expense from joint venture [1]	(1)	-	(4)	(4)	(5)	-	(4)	(4)
Income tax expense	(31)	(33)	(8)	(18)	(14)	(20)	(9)	(44)
Net income (loss)	**77**	**119**	**(69)**	**38**	**17**	**101**	**1**	**106**
Net income (loss) attributable to:								
Non-controlling interests	(3)	(3)	(4)	(2)	(3)	(2)	(2)	(2)
Shareholders of the Company	80	122	(65)	40	20	103	3	108
Net income (loss)	**77**	**119**	**(69)**	**38**	**17**	**101**	**1**	**106**

[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 and AFFO per share are measures 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 off-coal compensation that will be received annually,
- remove the tax equity financing project investors' shares of AFFO associated with assets under tax equity financing structures so only the Company's share is reflected in the overall metric,
- deduct sustaining capital expenditures and preferred share dividends,
- 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.

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	
	2022	**2021**	**2022**	**2021**
Net cash flows from operating activities per condensed interim consolidated statements of cash flows	**108**	**129**	**523**	**335**
Add (deduct) items included in calculation of net cash flows from operating activities per condensed interim consolidated statements of cash flows:				
Interest paid	16	20	54	61
Realized gains on settlement of interest rate derivatives	-	(12)	-	(12)
Change in fair value of derivatives reflected as cash settlement	52	7	45	11
Distributions received from joint venture	(2)	(2)	(2)	(5)
Miscellaneous financing charges paid [1]	2	2	4	3
Income taxes paid	5	-	17	5
Change in non-cash operating working capital	75	35	(105)	15
	148	50	13	78
Net finance expense [2]	(29)	(29)	(60)	(64)
Current income tax expense [3]	(9)	(13)	(24)	(16)
Sustaining capital expenditures [4]	(30)	(29)	(55)	(47)
Preferred share dividends paid	(10)	(13)	(20)	(26)
Remove tax equity interests' respective shares of adjusted funds from operations	(4)	(2)	(8)	(6)
Adjusted funds from operations from joint venture	6	5	11	9
Line Loss Rule Proceeding [5]	-	(7)	-	(13)
Adjusted funds from operations	**180**	**91**	**380**	**250**
Weighted average number of common shares outstanding (millions)	**116.4**	**109.7**	**116.3**	**108.3**
Adjusted funds from operations per share ($)	**1.55**	**0.83**	**3.27**	**2.31**

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.

4 Includes sustaining capital expenditures net of partner contributions of $1 million and $2 million for the three and six months ended June 30, 2022, respectively, compared with $2 million and $7 million for the three and six months ended June 30, 2021, respectively.

5 Consistent with the Company's definition of AFFO described above pertaining to the LLR Proceeding, AFFO for the three months and six months ended June 30, 2021 is impacted only by the Company's net obligations related to the 2006-2009 and 2010–2013 invoice tranches (see Contingent Liabilities, Other Legal Matters 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 attributable to common shareholders and normalized earnings per share are based on net income (loss) attributable to shareholders of the Company 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 2022	**Mar 2022**	**Dec 2021**	**Sep 2021**	**Jun 2021**	**Mar 2021**	**Dec 2020**	**Sep 2020**
Basic earnings (loss) per share ($)	**0.59**	**0.96**	**(0.67)**	**0.23**	**0.05**	**0.83**	**(0.09)**	**0.89**
Net income (loss) attributable to shareholders of the Company per condensed interim consolidated statements of income (loss)	**80**	**122**	**(65)**	**40**	**20**	**103**	**3**	**108**
Preferred share dividends including Part VI.1 tax	(11)	(10)	(13)	(13)	(14)	(14)	(13)	(14)
Earnings (loss) attributable to common shareholders	69	112	(78)	27	6	89	(10)	94
Unrealized changes in fair value of derivatives [1]	14	(2)	83	48	25	(10)	12	(28)
Genesee 2 forced outage	-	-	(5)	(12)	-	-	-	-
Provision for contingency	-	-	-	(6)	6	-	-	-
Impairment losses (reversal)	-	-	41	6	(2)	-	10	-
Reduction in applicable jurisdictional tax rates	-	-	10	-	-	(10)	-	-
Provision for Line Loss Rule Proceeding	-	-	-	-	-	(1)	1	-
Other	5	(2)	4	-	-	-	-	3
Normalized earnings attributable to common shareholders	**88**	**108**	**55**	**63**	**35**	**68**	**13**	**69**
Weighted average number of common shares outstanding (millions)	116.4	116.2	116.0	115.5	109.7	106.8	105.7	105.1
Normalized earnings per share ($)	**0.76**	**0.93**	**0.47**	**0.55**	**0.32**	**0.64**	**0.12**	**0.66**

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

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Three months ended June 30		Six months ended June 30	
	2022	2021	2022	2021
Revenues and other income	713	387	1,214	941
Adjusted EBITDA [1]	319	241	667	544
Net income	77	17	196	118
Net income attributable to shareholders of the Company	80	20	202	123
Normalized earnings attributable to common shareholders [1]	88	35	196	103
Basic earnings per share ($)	0.59	0.05	1.56	0.88
Diluted earnings per share ($) [2]	0.59	0.05	1.55	0.87
Normalized earnings per share ($) [1]	0.76	0.32	1.69	0.95
Net cash flows from operating activities	108	129	523	335
Adjusted funds from operations [1]	180	91	380	250
Adjusted funds from operations per share ($) [1]	1.55	0.83	3.27	2.31
Purchase of property, plant and equipment and other assets	147	151	279	248
Dividends per common share, declared ($)	0.5475	0.5125	1.0950	1.0250
Dividends per Series 1 preferred share, declared ($)	0.1638	0.1638	0.3276	0.3276
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 ($) [3]	N/A	0.3750	N/A	0.7500
Dividends per Series 9 preferred share, declared ($)	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, 2022	December 31, 2021
Loans and borrowings including current portion	3,064	3,360
Total assets	9,155	9,073

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 and Ratios.

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

3 On December 31, 2021, the Company redeemed all of its 8 million issued and outstanding 6.00% cumulative rate reset preference shares, Series 7.

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

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

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 and six months ended June 30, 2022 was higher than the corresponding period in 2021 primarily due to:

- higher adjusted EBITDA results mainly attributable to the strong generation and realized power pricing on our Alberta commercial facilities, more frequent dispatch and strong availability from our U.S. contracted thermal facilities and strong wind resources experienced at our U.S. wind facilities,
- lower preferred share dividends paid due to the redemption of Series 7 preferred shares by the Company in the fourth quarter of 2021,
- lower net finance expense incurred in the first half of 2022 compared with the same period in 2021 mainly driven by lower loans and borrowings outstanding; and
- the impacts of the Company's obligation related to the second and third tranches of LLR Proceeding in the first half of 2021 compared to no LLR proceeding impacts in the current period.

These increases to AFFO were partially offset by higher sustaining capital expenditures and, on the year-to-date, higher current income tax expenses.

The increase in purchases of property, plant and equipment and other assets for the six months ended June 30, 2022 is discussed in Liquidity and Capital Resources.

SIGNIFICANT EVENTS

Advancement of carbon capture project at Genesee

On June 27, 2022, the Company announced it had partnered with Mitsubishi Heavy Industries Group and Kiewit Energy Group on a front-end engineering and design (FEED) study for the Genesee CCS Project advancing the commercial application of CCS technology at its Genesee Generating Station in Alberta.

Appointment to the Board of Directors

Effective June 1, 2022, Gary Bosgoed was appointed to the Company's Board of Directors. With this appointment, Capital Power's Board of Directors consists of 10 directors, including 40% women and 30% with diversity beyond gender.

Executed 4.5-year contract renewal for Island Generation

On May 16, 2022, the Company announced the execution of a 4.5-year Electricity Purchase Agreement (EPA) through October 2026 for its Island Generation facility with BC Hydro. The EPA is subject to regulatory approval by the British Columbia Utilities Commission. The terms of the 4.5-year EPA are consistent with the Company's expectations when it recorded a $52 million impairment in 2021.

Executed 10-year contract for Whitla Wind

On March 18, 2022, the Company announced that it executed a 10-year renewable energy agreement with MEGlobal Canada ULC. The agreement commenced April 1, 2022 and covers the renewable energy for the balance of our Whitla Wind facility.

Strathmore Solar begins commercial operations

On March 17, 2022, Strathmore Solar, a 41 MW facility in Strathmore Alberta, began commercial operations. The project was completed on-schedule at a total cost of $58 million compared to the original projected total cost of $53 million (see Liquidity and Capital Resources). The facility is fully contracted with 100% of the renewable energy and associated renewable energy credits sold to TELUS Communications under a 25-year power purchase agreement.

Approval of normal course issuer bid

During the first quarter of 2022, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 8 million of its outstanding common shares during the one-year period from February 28, 2022 to February 27, 2023.

SUBSEQUENT EVENTS

Dividend increase

On July 29, 2022, the Company's Board of Directors approved an increase of 6% in the annual dividend for holders of its common shares, from $2.19 per common share to $2.32 per common share. This increased common share dividend will commence with the third quarter 2022 quarterly dividend payment on October 31, 2022 to shareholders of record at the close of business on September 30, 2022.

Acquisition of Midland Cogeneration Venture

On July 12, 2022, Capital Power announced it had partnered with Manulife Investment Management on behalf of the Manulife Infrastructure Fund II and its affiliates to acquire 100% of the interests in MCV Holding Company, which owns Midland Cogeneration Venture (Midland Cogen), a 1,633 MW natural gas combined-cycle cogeneration facility. Midland Cogen is being acquired from OMERS Infrastructure Management Inc and its co-investors for a total purchase price of $1,163 million (US$894 million), including the assumption of $678 million (US$521 million) of project level debt. The transaction is expected to close in the third quarter of 2022, subject to regulatory approvals and other customary closing conditions.

Located in Michigan, Midland Cogen, is the largest gas-fired cogeneration facility in North America, is a critical asset to support grid reliability during the transition to renewables and is well-positioned, given anticipated market conditions, for recontracting beyond 2030. Capital Power and Manulife Investment Management will each own a

50% interest in MCV Holding Company and will each contribute approximately $242 million (US$186 million) subject to working capital and other closing adjustments. Capital Power will finance its share of the transaction using cash on hand and its existing credit facilities. Capital Power will be responsible for operations and maintenance and asset management for which it will receive an annual management fee.

The acquisition supports Capital Power's strategy of acquiring mid-life contracted natural gas assets that are strategically positioned within their power markets. Acquisition highlights include:

- Capital Power's share of expected average adjusted EBITDA of US$59 million per year (ranging from US$85 million in 2023 and declining to US$45 million in 2027).
- based on the expected financing, the 5-year average accretion for Capital Power's AFFO is expected to be US$0.30 per share, reflecting a 7% increase, or an average AFFO of US$35 million per year during the years 2023-2027.
- power purchase agreement with Consumers Energy (rated Baa1/A-/A-) for 1,240 MW of capacity to 2030
- steam and electricity purchase agreement with Corteva Agriscience (rated NA/A-/A) and Dow Silicones (rated Baa2/BBB/BBB+) to 2035.
- approximately 15% (243 MW) of uncontracted capacity is available to sell into the MISO Zone 7 market
- located on 1,200 acres leased from Consumers Energy. Current layout and additional space allow for additional turbines, battery installation or a hybrid opportunity.

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, 2022 compared with 2021 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, 2021		**17**		**118**
Increase (decrease) in adjusted EBITDA:				
Alberta commercial facilities and portfolio optimization	46		73	
Western Canada contracted facilities	2		13	
Ontario contracted facilities	7		15	
U.S. contracted facilities	32		30	
Corporate	(9)	78	(8)	123
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		(4)		(15)
Increase in depreciation and amortization expense		(7)		(12)
Decrease in losses on disposals and other transactions		2		-
Decrease in impairment reversal		(2)		(2)
Increase in foreign exchange loss		(5)		(5)
Decrease in finance expense and depreciation expense from joint venture		4		4
Decrease in net finance expense		11		15
Increase in income before tax		77		108
Increase in income tax expense		(17)		(30)
Increase in net income		**60**		**78**
Consolidated net income for the periods ended June 30, 2022		**77**		**196**

Results by facility category and other

	Three months ended June 30							
	2022	2021	2022	2021	2022	2021	2022	2021
	Electricity generation (GWh) [1]		Facility availability (%) [2]		Revenues and other income (unaudited, $ millions)		Adjusted EBITDA (unaudited, $ millions) [3]	
Total electricity generation, average facility availability and facility revenues	6,638	4,975	92	84	697	528		
Alberta commercial facilities								
Genesee 1	733	708	86	92	93	78		
Genesee 2	843	701	100	100	108	80		
Genesee 3	1,010	951	100	95	122	100		
Clover Bar Energy Centre 1, 2 and 3	72	67	89	94	14	14		
Joffre	187	180	96	95	34	27		
Shepard	814	379	100	50	66	38		
Halkirk Wind	124	111	98	98	19	14		
Clover Bar Landfill Gas	3	-	74	-	-	-		
Alberta commercial facilities	3,786	3,097	96	87	456	351		
Portfolio optimization	N/A	N/A	N/A	N/A	(33)	(37)		
	3,786	3,097	96	87	423	314	182	136
Western Canada contracted facilities								
Island Generation	-	114	100	89	4	8		
Quality Wind	70	83	98	98	8	9		
EnPower	4	7	99	93	-	-		
Whitla Wind	349	178	97	98	16	8		
Strathmore Solar [4]	26	N/A	100	N/A	2	N/A		
	449	382	99	94	30	25	20	18
Ontario contracted facilities								
York Energy [5]	6	5	100	100	N/A	N/A		
East Windsor	3	4	76	100	10	7		
Goreway	234	159	59	89	67	47		
Kingsbridge 1	23	20	99	98	2	2		
Port Dover and Nanticoke Wind	67	66	99	99	10	10		
	333	254	71	93	89	66	56	49
U.S. contracted facilities								
Decatur Energy, Alabama	752	240	100	51	23	12		
Arlington Valley, Arizona	659	461	96	78	55	35		
Beaufort Solar, North Carolina	9	8	99	97	1	1		
Bloom Wind, Kansas	208	177	94	98	8	9		
Macho Springs Wind, New Mexico	48	41	98	98	5	5		
New Frontier Wind, North Dakota	116	93	95	97	7	5		
Cardinal Point Wind, Illinois	167	141	98	97	15	14		
Buckthorn Wind, Texas	111	81	90	94	8	5		
	2,070	1,242	97	72	122	86	67	35
Corporate [7]					33	32	(6)	3
Unrealized changes in fair value of commodity derivatives and emission credits					16	(136)		
Consolidated revenues and other income and adjusted EBITDA					**713**	**387**	**319**	**241**

	Six months ended June 30							
	2022	2021	2022	2021	2022	2021	2022	2021
	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	13,531	10,605	93	90	1,304	1,081		
Alberta commercial facilities								
Genesee 1	1,523	1,324	89	92	168	141		
Genesee 2	1,660	1,282	98	100	185	141		
Genesee 3	1,990	1,855	100	95	207	188		
Clover Bar Energy Centre 1, 2 and 3	184	90	88	97	32	22		
Joffre	396	383	98	98	62	53		
Shepard	1,600	1,182	100	75	113	91		
Halkirk Wind	274	262	98	98	37	33		
Clover Bar Landfill Gas	3	-	83	-	1	-		
Alberta commercial facilities	7,630	6,378	96	92	805	669		
Portfolio optimization	N/A	N/A	N/A	N/A	74	(12)		
	7,630	6,378	96	92	879	657	374	301
Western Canada contracted facilities								
Island Generation	7	142	100	94	13	18		
Quality Wind	196	210	96	98	25	25		
EnPower	12	18	99	91	1	1		
Whitla Wind	785	413	98	98	39	18		
Strathmore Solar [4]	29	N/A	100	N/A	2	N/A		
	1,029	783	98	96	80	62	60	47
Ontario contracted facilities								
York Energy [5]	14	9	100	100	N/A	N/A		
East Windsor	6	4	87	99	18	15		
Goreway	833	393	80	94	145	105		
Kingsbridge 1	58	50	98	99	5	4		
Port Dover and Nanticoke Wind	167	147	99	99	25	22		
	1,078	603	85	96	193	146	121	106
U.S. contracted facilities								
Roxboro, North Carolina [6]	N/A	57	N/A	100	N/A	7		
Southport, North Carolina [6]	N/A	60	N/A	100	N/A	11		
Decatur Energy, Alabama	1,369	596	97	65	50	36		
Arlington Valley, Arizona	1,135	1,006	87	89	88	59		
Beaufort Solar, North Carolina	15	14	100	98	1	1		
Bloom Wind, Kansas	388	342	94	96	17	18		
Macho Springs Wind, New Mexico	82	79	98	98	9	9		
New Frontier Wind, North Dakota	238	196	96	95	13	11		
Cardinal Point Wind, Illinois	363	311	97	98	34	30		
Buckthorn Wind, Texas	204	180	91	94	14	22		
	3,794	2,841	94	81	226	204	120	90
Corporate [7]					65	62	(8)	-
Unrealized changes in fair value of commodity derivatives and emission credits					(229)	(190)		
Consolidated revenues and other income and adjusted EBITDA					**1,214**	**941**	**667**	**544**

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 and Ratios.

[4] Strathmore Solar was commissioned on March 17, 2022.

[5] York Energy is accounted for under the equity method. Capital Power's share of the facility's net income is included in income from joint 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 $10 million and $19 million for three and six months ended June 30, 2022, respectively, compared with $7 million and $15 million for the three and six months ended June 30, 2021. The facility's revenues are not included in the above results.

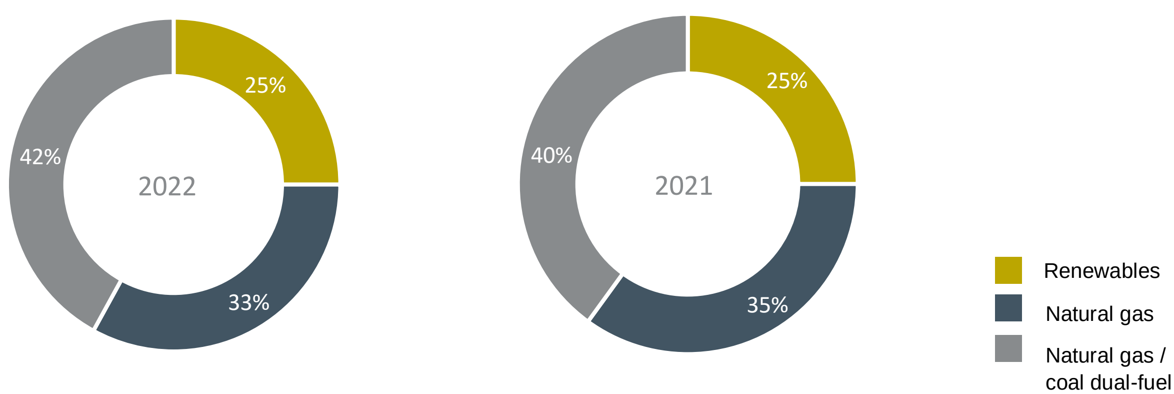
[6] The PPAs for the Southport and Roxboro facilities expired March 31, 2021, and the facilities also ceased operations. Decommissioning of the facilities commenced in the second quarter of 2021 and is ongoing.

[7] Corporate revenues were offset by interplant category eliminations.

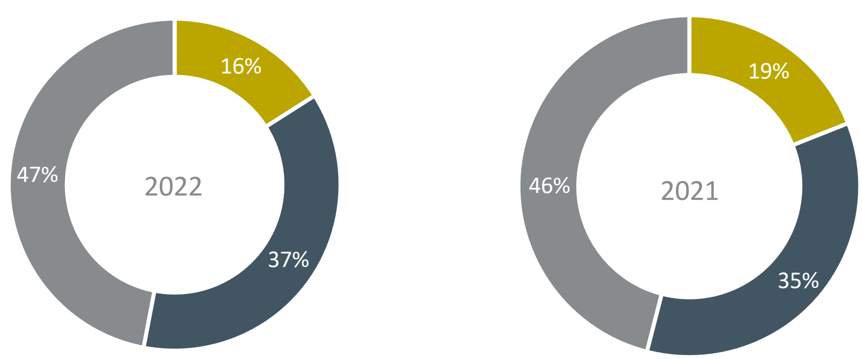
Adjusted EBITDA and revenues and other income by fuel type for the six months ended June 30

Alberta commercial portfolio optimization amounts in adjusted EBITDA and revenues and other income are allocated to fuel source based on generation and off-coal compensation is reflected within natural gas / coal dual-fuel. The period-over-period increases in percentages from the Company's natural gas/coal dual-fuel facilities are largely driven by higher generation and realized Alberta power prices in 2022 as compared to 2021.

Adjusted EBITDA by fuel type



Revenues and other income by fuel type[1]



[1] The allocation of revenues and other income by fuel type excludes the impacts of unrealized changes in fair value of commodity derivatives and emission credits.

Energy prices and hedged positions

Alberta portfolio metric	Unit	Three months ended June 30 2022	Three months ended June 30 2021	Six months ended June 30 2022	Six months ended June 30 2021	Year ended December 31, 2021
Power						
Hedged position [1]	Percentage of baseload generation sold forward at beginning of year (%)	98	51	83	38	29
Spot power price average	$ per MWh	122	105	106	100	102
Realized power price [2]	$ per MWh	85	75	84	76	78
Natural gas						
Hedged position[3]	Percentage of natural gas requirements purchased forward at beginning of year (%)	100	96	100	84	78
Spot natural gas price average (AECO) [4]	$ per GJ	6.86	3.03	5.69	3.05	3.50

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

2 Realized power price is the average aggregate price realized through selling power generation into the spot market, the Company's commercial contracted sales and portfolio optimization activities. When long-term forward portfolio optimization hedges are transacted, they reflect the market's expectations for future period pricing. Ultimately, spot pricing may vary from expected forward pricing due to a number of factors resulting in realized power prices in a given period that can differ materially from spot pricing.

3 Based on forecasted natural gas requirements from the Company's most recent forecast. Actual fuel requirements for Alberta facilities may differ significantly as a result of dispatch decisions.

4 AECO refers to the historical virtual trading hub located in Alberta and known as the NOVA Inventory Transfer system operated by TC Energy. Realized natural gas price is the average aggregate price realized through purchasing of natural gas from the spot market, the Company's commercial contracted purchases and portfolio optimization activities. For the current and comparative periods, this results in realized natural gas prices that are significantly lower than spot natural gas prices.

Alberta commercial facilities and portfolio optimization

The Alberta power spot price averaged $122 per MWh and $106 per MWh for the three and six months ended June 30, 2022, respectively, which were higher than the corresponding periods in 2021. This was primarily due to higher natural gas costs resulting in competitive bidding behaviors and pricing of natural gas units higher in the merit curve. In addition, increased carbon compliance pricing from $40 per tonne in 2021 to $50 per tonne in 2022, lower imports and overall increase in demand contributed to higher spot price in the current year.

For the three and six months ended June 30, 2022, generation and availability were higher than the comparable periods in 2021. These increases were primarily driven by Alberta power market fundamentals and our offer strategy. A summary of the larger outages for Alberta commercial facilities is below:

- a planned outage at Shepard in the second quarter of 2021 compared with no outages thus far in 2022;
- longer planned outages at Clover Bar Energy Center in 2022 compared with 2021. Clover Bar Energy Center also experienced an unplanned outage in the first quarter of 2022 compared with no unplanned outages in the first half of 2021;
- shorter unplanned outages and no planned outage in the first two quarters of 2022 compared with unplanned outages and a planned outage in the second quarter of 2021 at Genesee 3; and
- a planned outage at Genesee 1 across the first two quarters of 2022 which was longer in duration than the unplanned outages that unit experienced across the same quarters in 2021.

Revenues and other income for the three and six months ended June 30, 2022 were higher than the comparable periods in 2021 primarily due to the higher generation at Shepard, the Genesee units and Clover Bar Energy Centre as well as higher captured prices for the portfolio in 2022 compared with 2021.

Adjusted EBITDA for the three and six months ended June 30, 2022 was higher than the comparable period in 2021 primarily due to the aforementioned higher revenues and other income. These favourable variances were partially offset by higher coal and natural gas prices, as well as higher volumes burned in 2022 compared with 2021 given increased generation. In addition, the aforementioned higher generation and carbon compliance pricing in 2022, compared with 2021, led to higher emissions costs in 2022 compared with 2021.

Western Canada contracted facilities

Generation, revenues and other income, and adjusted EBITDA for the three and six months ended June 30, 2022 were higher compared to the corresponding periods in 2021 primarily due to the commencement of operations for phases 2 and 3 of Whitla Wind on December 1, 2021 and Strathmore Solar on March 17, 2022, partially offset by minimal dispatch at Island Generation in 2022 compared with 2021. Generation was also higher in 2022 compared with 2021 due to higher wind resource availability at phase 1 of Whitla Wind in 2022. The higher revenue and other income, and adjusted EBITDA in 2022 compared with 2021 was partially offset by lower revenues at Island Generation during the period where the old EPA expired and the new EPA was being negotiated (see Significant Events). Availability for the three and six months ended June 30, 2022 was higher compared to the corresponding periods in 2021 primarily due to a planned outage in the second quarter of 2021 at Island Generation compared with no outages thus far in 2022 coupled with strong availability at the aforementioned facilities that commenced operations within the last year.

Ontario contracted facilities

Generation, revenues and other income, and adjusted EBITDA for the three and six months ended June 30, 2022 were higher compared to the corresponding periods in 2021 primarily due to higher dispatch at Goreway, largely driven by nuclear refurbishment activities which are limiting power supply in the Ontario market and warmer temperatures. In addition, higher wind resourcing experienced at Port Dover and Nanticoke Wind and higher market and ancillary services revenues at East Windsor contributed to higher revenues and other income in 2022 compared with 2021. Partially offsetting these impacts within adjusted EBITDA for the three and six months ended June 30, 2022 were higher natural gas consumption and pricing and higher outage costs due to a longer planned outage in the second quarter of 2022 compared with the same period in 2021 at Goreway. Unplanned outages at East Windsor in 2022 compared with minimal outage hours in 2021 also contributed to the lower availability between the comparable periods.

U.S. contracted facilities

Generation and availability for the three and six months ended June 30, 2022 were higher than the comparable periods in 2021 primarily due to activities at Decatur Energy and Arlington Valley. Decatur Energy was dispatched more frequently and did not have a planned outage in 2022 compared with a planned outage across both the first and second quarters of 2021, partially offset by an unplanned outage early in 2022. Arlington Valley was also dispatched more frequently and had a longer planned outage in the first quarter of 2022 compared with the second quarter of 2021, offset by lower unplanned outage hours in the second quarter of 2022 compared with the second quarter of 2021. In addition, overall generation from the renewables facilities was higher in 2022 compared with 2021 due to higher wind resource availability. Offsetting these increases to generation was the retirement of the Southport and Roxboro facilities effective March 31, 2021.

Revenues and other income were higher in the three and six months ended June 30, 2022 compared to the corresponding periods in 2021 primarily due to higher heat rate call option (HRCO) revenues at Arlington Valley driven by the impact of higher natural gas prices and higher market sales. Additionally, Decatur Energy received higher contracted variable revenues in 2022 compared with 2021 as a result of higher generation and availability at that facility, as well as higher capacity revenue as a result of the extension to the tolling agreement that was previously announced in the third quarter of 2021 along with the increased capacity rating of the facility following the completion of upgrades in 2021. In addition, Cardinal Point Wind earned higher market revenue throughout 2022 and REC sales in the first quarter of 2022, the latter due to timing, partially offset by lower tax attributes and higher hedge losses in 2022 compared with 2021. The higher revenue and other income for the six months ended June 30, 2022 compared with the same period in 2021 was partially offset by the retirement of the Southport and Roxboro facilities on March 31, 2021 and the revenue impact of the extreme weather event at Buckthorn Wind in February of 2021.

Adjusted EBITDA was higher in the three and six months ended June 30, 2022 compared with 2021 primarily due to the impacts of the aforementioned revenue and other income variances, lower maintenance costs at Decatur due to no planned outage in 2022, and the retirement of the Southport and Roxboro facilities who contributed a negative adjusted EBITDA in the first quarter of 2021. Additionally, Arlington Valley fulfilled certain HRCO requirements by procuring cost effective replacement power instead of operating the facility and therefore incurred lower gas costs in 2022 compared with 2021. Maintenance costs at Arlington Valley were lower in 2022 compared with 2021, primarily due to lower outage costs despite overall outage hours in the first six months of 2022 being consistent with the same period in 2021.

Corporate

Corporate results include (i) revenues for cost recoveries and other income related to off-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 consistent in 2022 compared with 2021. Adjusted EBITDA for the three and six months ended June 30, 2022 was lower than the comparable periods in 2021 mainly due to higher business development expenses and the reversal of a contingent consideration provision in 2021 related to a previous acquisition that was no longer required.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Three months ended June 30			
	2022	**2021**	**2022**	**2021**
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	(63)	(20)	(53)	1
Unrealized losses on U.S. power derivatives	(5)	(49)	(5)	(50)
Unrealized gains (losses) on natural gas derivatives	78	(66)	25	28
Unrealized gains (losses) on emission derivatives	6	(1)	6	(1)
Unrealized losses on emission credits held for trading	-	-	(1)	(2)
	16	**(136)**	**(28)**	**(24)**

(unaudited, $ millions)	Six months ended June 30			
	2022	**2021**	**2022**	**2021**
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	(80)	(22)	(73)	4
Unrealized losses on U.S. power derivatives	(88)	(84)	(88)	(84)
Unrealized (losses) gains on natural gas derivatives	(75)	(75)	106	57
Unrealized gains (losses) on emission derivatives	14	(9)	14	(9)
Unrealized (losses) gains on emission credits held for trading	-	-	(5)	1
	(229)	**(190)**	**(46)**	**(31)**

The Company's revenues and other income and adjusted EBITDA relating to its Alberta commercial facilities and portfolio optimization, U.S. wind facilities and certain Alberta contracted renewables 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 noted portfolio and 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, 2022, the Alberta power portfolio recognized unrealized losses on Alberta power derivatives of $53 million and $73 million respectively, due to the impact of increasing forward prices on net forward sale contracts, offset partly by the reversal of prior period unrealized losses on positions that settled during those periods. During the comparable periods in 2021, the Alberta power portfolio recognized unrealized gains of $1 million and $4 million respectively, due to the impact of increasing forward Alberta power prices on the value of forward purchase contracts, partially offset by the reversal of prior period unrealized gains on positions that settled during those periods.

During the three and six months ended June 30, 2022, the U.S. power portfolio recognized unrealized losses of $5 million and $88 million respectively, as a result of the impact of increasing forward power prices on forward sale contracts associated with the Company's U.S Wind facilities. During the comparable periods in 2021, the U.S. power portfolio recognized unrealized losses of $50 million and $84 million respectively, due to the impact of increasing forward prices on forward sale contracts.

During the three and six months ended June 30, 2022, the Company recognized unrealized gains on natural gas derivatives of $25 million and $106 million respectively, due primarily to the impact of increasing forward prices on forward purchase contracts. This was partially offset by the reversal of prior period unrealized gains on positions that settled during these periods. During the comparable periods in 2021, the Company recognized unrealized gains of $28 million and $57 million respectively, mainly as a result of increasing forward prices on forward purchase contracts.

During the three and six months ended June 30, 2022, the Company recognized unrealized gains on emission derivatives of $6 million and $14 million, mainly as a result of the reversal of prior period unrealized losses on positions that settled during the quarter, as well as the impact of increasing forward prices on net forward purchase contracts. During the six months ended June 30, 2021, unrealized losses on emission derivatives of $9 million were recognized as a result of increasing forward prices on forward sale contracts as well as the reversal of prior period unrealized gains on positions that settled during that period.

During the six months ended June 30, 2022, the Company recognized unrealized losses of $5 million on emission credits held for trading, due to the reversal of prior period unrealized gains on inventory sold during that time. During the comparable period of 2021, unrealized gains on emission credits held for trading were immaterial.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Three months ended June 30		Six months ended June 30	
	2022	**2021**	**2022**	**2021**
Interest on borrowings less capitalized interest	(30)	(34)	(61)	(71)
Realized losses on settlement of interest rate derivatives	(1)	-	(3)	(2)
Other net finance expense – interest on off-coal compensation from the Province of Alberta, lease liability interest, sundry interest, guarantee and other fees	(2)	-	(5)	(1)
	(33)	(34)	(69)	(74)
Unrealized gains (losses) representing changes in the fair value of interest rate derivatives	6	(1)	14	9
Other net finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to off-coal compensation from the Province of Alberta	(8)	(11)	(17)	(22)
Total net finance expense	(35)	(46)	(72)	(87)
Depreciation and amortization	(139)	(132)	(281)	(269)
Impairment reversal	-	2	-	2
Foreign exchange loss	(7)	(2)	(6)	(1)
Losses on disposals and other transactions	(1)	(3)	(1)	(1)
Finance expense and depreciation expense from joint venture	(1)	(5)	(1)	(5)
Income tax expense	(31)	(14)	(64)	(34)
Net loss attributable to non-controlling interests	3	3	6	5

Net finance expense

Lower net finance expense for the three and six months ended June 30, 2022 compared with the same period in the prior year largely reflects lower interest on decreased loans and borrowings outstanding during the period, lower accretion due to off-coal compensation, higher capitalized interest as a result of the continuing advancement of the Genesee repowering project, and higher unrealized gains on non-hedge interest rate swaps in 2022 driven by larger impacts of increasing market interest rates in the second quarter of 2022 compared to 2021.

Depreciation and amortization

Depreciation and amortization for the three and six months ended June 30, 2022 increased compared with the same period in the prior year primarily due to phases 2 and 3 of Whitla Wind (commenced commercial operations in December 2021), Strathmore Solar (commenced commercial operations in March 2022, see Significant Events) and further shortened useful life of the Genesee Mine, partially offset by the classification of Island Generation EPA as a finance lease during the second quarter of 2022 (see Significant Events). On a year-to-date basis, depreciation expense was partially offset by Southport and Roxboro being fully depreciated as of the end of the first quarter of 2021.

Foreign exchange loss

As at June 30, 2022, the Company had no outstanding foreign currency non-hedge purchase contracts. Foreign exchange loss in the year reflects losses incurred on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes.

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 sale 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 sale contracts in the period.

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 $4 million for the three and six months ended June 30, 2022 compared with the same periods in 2021 driven by larger impacts of increasing interest rates during 2022 compared to 2021 resulting in higher gains on the interest rate non-hedge held within the York Energy joint venture.

Income tax expense

For the three and six months ended June 30, 2022, income tax expense increased $17 million and $30 million, respectively, compared with the corresponding periods in 2021 primarily due to higher overall consolidated income before tax. In addition, Capital Power recognized a $10 million deferred income tax benefit in the prior period that was attributable to lower applicable jurisdictional tax rates, of which there is no comparable tax recovery recognized in 2022. The above increases are partially offset by a decrease in amounts attributable to tax-equity interests in 2022 compared to 2021.

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 INCOME (LOSS)

(unaudited, $ millions)	Three months ended June 30		Six months ended June 30	
	2022	**2021**	**2022**	**2021**
Net income	77	17	196	118
Other comprehensive income (loss):				
Actuarial gain related to the Company's defined benefit pension plan	10	-	10	-
Net unrealized losses on derivative instruments	(61)	(99)	(2)	(106)
Net realized losses on derivative instruments reclassified to net income	47	50	52	86
Unrealized foreign exchange gains (losses) on the translation of foreign operations	34	(5)	23	(18)
Total other comprehensive income (loss), net of tax	30	(54)	83	(38)
Comprehensive income (loss)	**107**	**(37)**	**279**	**80**

Other comprehensive income (loss) includes fair value adjustments on financial instruments held by the Company to hedge market risks and which meet the requirements of hedges for accounting purposes. To the extent that such hedges are ineffective, any related gains or losses are recognized in net 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, 2021 to June 30, 2022 were as follows:

(unaudited, $ millions)	**June 30, 2022**	**December 31, 2021**	**Increase (decrease)**	**Primary reason for increase (decrease)**
Trade and other receivables[1]	568	474	94	Increase primarily due to increased accrued receivables from higher dispatch at Goreway, other receivables from U.S. trading activities and higher capacity revenues at Arlington Valley from tolling revenue compared to lower heat rate call option revenue at December 2021.
Finance lease receivable (including current portion)	43	-	43	Island Generation's new EPA (see Significant Events) is classified as a finance lease, resulting in the recognition of a finance lease receivable and some revenues being classified as finance lease income whereas the previous EPA was classified as an operating lease and presented within property, plant and equipment and depreciated.
Property, plant and equipment	6,139	6,203	(64)	Decrease due to the derecognition of Island Generation's net assets due to new EPA being classified as a finance lease (see Significant

(unaudited, $ millions)	June 30, 2022	December 31, 2021	Increase (decrease)	Primary reason for increase (decrease)
				Events), the impact of increasing interest rates on decommissioning assets, foreign exchange impacts and depreciation. These impacts were partially offset by capital additions for Genesee 1 and 2 repowering, Strathmore Solar and Enchant Solar.
Trade and other payables	789	624	165	Increase due to higher trading margin account payables due to margin account withdrawals resulting from increasing forward natural gas prices on net forward purchase contracts, increased capital accruals from repowering of Genesee 1 and 2 and higher natural gas and outage accruals at Goreway. Partially offsetting these increases were lower emission compliance obligations due to settlement of the 2021 obligation in the second quarter of 2022 and the payment of the Arlington Valley long-term service agreement costs.
Net derivative financial instruments liabilities	183	274	(91)	Decrease due to reduction in interest rate swap liabilities resulting from increasing forward interest rates and the impact of increasing forward natural gas prices on net forward purchase contracts, offset partly by the impact of increasing forward prices on forward sale contracts for our U.S. contracted wind and certain Alberta contracted renewable assets.
Loans and borrowings (including current portion)	3,064	3,360	(296)	Decrease primarily due to repayments of U.S. dollar bank loans and allocation of income tax benefits to tax-equity investors associated with the Company's tax-equity structures.
Provisions (including current portion)	355	461	(106)	Decrease mainly due to revisions to existing decommissioning and employee benefits provisions driven by increases in interest rates and payment of accrued employee benefits partially offset by increases to the Genesee Mine decommission provision.
Net deferred tax liabilities	625	567	58	Increase primarily due to recognition of taxable temporary differences that will reverse in the future, and changes in derivative financial instrument balances.

[1] Excludes current portion of finance lease receivable.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Six months ended June 30		
Cash inflows (outflows)	**2022**	**2021**	**Change**
Operating activities	523	335	188
Investing activities	(279)	(241)	(38)
Financing activities	(439)	(328)	(111)

Operating activities

Cash flows from operating activities for the six months ended June 30, 2022 increased compared with the same period in 2021 mainly due to:

- cash flow impacts of the increases in adjusted EBITDA described in Consolidated Net Income and Results of Operations, higher generation and realized Alberta power pricing and strong results from our U.S. contracted facilities;
- favorable changes in non-cash working capital mainly driven by higher margin account withdrawals resulting from the impact of increasing forward natural gas prices on net forward purchase contracts. In addition, given higher Alberta power pricing, collections in the first quarter of 2022 for receivables outstanding at December 2021 was higher as compared to those for December 2020 in the first quarter of 2021; and
- the net settlement of tranches 2 and 3 of the LLR Proceeding invoices in 2021 with no comparable impacts in 2022.

Partially offsetting the above increases are 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 2022 compared with the same period in 2021, most notably driven by the impact of increasing forward power prices on net forward sale contracts in 2022.

Investing activities

Cash flows used in investing activities for the six months ended June 30, 2022 increased compared with the same period in 2021 due to higher cash capital expenditures, most notably increased spend on the repowering of Genesee 1 and 2 and Enchant Solar.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2022 actual	Six months ended June 30, 2022 actual	Balance of 2022 estimated [1,2]	Actual or projected total [2]	Targeted completion
Repowering of Genesee 1 and 2 [3]	238	158	258	1,192	Unit 1 in 2023 and unit 2 in 2024
Whitla Wind 2 and 3	242	2	8	252	Operations commenced December 2021
Strathmore Solar	51	7	-	58	Operations commenced March 2022
Enchant Solar [4]	19	41	64	124	Fourth quarter of 2022
Bear Branch Solar	2	-	3	60	Fourth quarter of 2024
Hornet Solar	2	1	3	118	Fourth quarter of 2024
Hunter's Cove Solar	2	-	3	82	Fourth quarter of 2024
Commercial initiatives [5]	182	6	7	198	
Development sites and projects	60	-	-		
Subtotal growth projects		**215**	**346**		
Sustaining – plant maintenance excluding Genesee Mine		57			
Total capital expenditures [6]		**272**			
Emission credits held for compliance		54			
Capitalized interest		(7)			
Additions of property, plant and equipment and other assets		**319**			
Change in other non-cash investing working capital and non-current liabilities		(40)			
Purchase of property, plant and equipment and other assets, net		**279**			

1 The Company's 2022 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 Projected total costs include the 210MW Genesee Battery Energy Storage System to be constructed as part of the repowering project. The battery storage addition will be going through the regulatory approval process in 2022 with an anticipated in-service date of late 2024.

4 Projected total costs have increased from the original projected cost of $102 million for Enchant Solar due to supply chain pressures and significant increases in transportation costs.

5 Commercial initiatives 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.

6 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, net.

Financing activities

Cash flows used in financing activities were higher in the six months ended June 30, 2022 mainly due to higher cash inflows from the issuance of common shares in the prior year and higher common share dividends paid in 2022 as the Company's Dividend Reinvestment Plan was suspended in the fourth quarter of 2021. This was partially offset by lower net repayments of loans and borrowings in the current year due to the repayment of U.S dollar bank loans in the second quarter of 2021.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at June 30, 2022			As at December 31, 2021		
	Maturity timing	Total facilities	Credit facility utilization	Available	Total facilities	Credit facility utilization	Available
Committed credit facilities	2026	1,000			1,000		
Letters of credit outstanding			112			30	
Bankers' acceptances outstanding			-			-	
Bank loans outstanding [1]			-			241	
		1,000	112	888	1,000	271	729
Bilateral demand credit facilities	N/A	777			773		
Letters of credit outstanding			658			465	
		777	658	119	773	465	308
Demand credit facilities	N/A	25	-	25	25	-	25
		1,802	**770**	**1,032**	**1,798**	**736**	**1,062**

[1] U.S. dollar denominated bank loans outstanding totaling nil (December 31, 2021 – US$191 million).

As at June 30, 2022, the committed credit facility utilization decreased $159 million compared with the utilization at December 31, 2021, due to repayment of U.S. dollar bank loans. The available credit facilities provide the Company with adequate funding for ongoing development projects.

The Company has a corporate credit rating of BBB- with a stable outlook from Standard & Poor's (S&P) which was affirmed in their latest report, published in April 2022. 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 in April 2022. 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 2022 include:

(unaudited, $ millions)	Six months ended June 30, 2022 actual	Balance of 2022 estimated	Total 2022 expected cash requirements[4]
Repayment of debt payable [1]	37	34	71
Interest on loans and borrowings	54	54	108
Capital expenditures – sustaining	55	73	128
Capital expenditures – ongoing growth projects [2]	169	329	498
Capital expenditures – commercial initiatives	6	7	13
Common share dividends [3]	128	134	262
Preferred share dividends	20	17	37
	469	**648**	**1,117**

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% annual dividend growth (see Subsequent Events).

4 Excludes the expected cash requirements to close the acquisition of Midland Cogen expected in the third quarter of 2022 (see Significant Events).

The Company uses a short-form base shelf prospectus to provide it with the ability, market conditions permitting, to obtain new debt and equity capital from external markets when required. Under the short-form base shelf prospectus, Capital Power may issue an unlimited number of common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities, including up to $2 billion of medium-term notes by way of a prospectus supplement. This prospectus expires in July 2024.

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

At June 30, 2022, the Company has $770 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, 2022	December 31, 2021
Loans and borrowings	3,064	3,360
Lease liabilities [1]	145	143
Less cash and cash equivalents	(184)	(387)
Net debt	3,025	3,116
Share capital	3,638	3,631
Deficit and other reserves	(653)	(790)
Non-controlling interests	11	18
Total equity	2,996	2,859
Total capital	**6,021**	**5,975**

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

CONTINGENT LIABILITIES, OTHER LEGAL MATTERS AND PROVISIONS

Refer to Contractual Obligations, Contingent Liabilities, Other Legal Matters and Provisions discussion in the Company's 2021 Integrated Annual Report for details on ongoing legal matters for which there were no notable updates in the current period.

Contingent liabilities

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

Line Loss Rule Proceeding

On May 31, 2022, an Alberta Government bill was passed with the intent to dissolve the Balancing Pool. Capital Power continues to expect that it will ultimately realize the full amount of the gross receivables related to line losses upon resolution of the dispute before the Court whether it be from the Balancing Pool or the designated entity assuming its residual responsibilities as will be identified in forthcoming amendments to provincial regulation enacting the dissolution.

RISKS AND RISK MANAGEMENT

For the six months ended June 30, 2022, the Company's business and operational risks have remained consistent with those described in the Company's 2021 Integrated Annual Report. Information pertaining to climate-related risks and opportunities can be found on the Company's website within its 2021 Climate Change Disclosure Report.

Details around the Company's approach to risk management, including the Company's principal risk factors and the associated risk mitigation strategies, are described in the Company's 2021 Integrated Annual Report. These factors and strategies have not changed materially in the six months ended June 30, 2022, however the Company continues to see an increase in supply chain risks including those described below.

The Russian government's invasion of Ukraine on February 24, 2022 set off historic policy actions and global coordination of sanctions and commitments to reduce dependency on Russian energy including natural gas. This has contributed to global supply chain disruptions, commodity price volatility and potential increases to inherent cybersecurity risk. We continue to mitigate supply chain risk pertaining to current development projects by locking in the prices of key materials where possible and employing the other supply chain risk mitigation strategies described in our 2021 Integrated Annual Report. A prolonged Russia-Ukraine conflict could impact future construction project costs with the risk of rising prices on key materials. The Russia-Ukraine conflict continues to evolve as well as the scope and severity of the economic sanctions. Accordingly, the indirect impacts of the Russia-Ukraine conflict transpiring through the global markets to the Company remains uncertain at this time, but management continues to monitor and assess the resulting impacts.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $281 million at June 30, 2022 ($366 million as at December 31, 2021) 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 $521 million and forward contracts to sell environmental credits totaling $421 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 2021 Integrated Annual Report for further details that supplement the recent developments discussed below:

Canada

Further to the climate plan and emission reduction announcements released by the Government of Canada as discussed in the Company's 2021 Integrated Annual Report, Environment and Climate Change Canada (ECCC) released a Clean Electricity Standard (CES) Discussion Paper on March 15, 2022.

The Discussion Paper described the intended role for a CES as part of a broader suite of policies intended to achieve the Federal Government's objective of achieving a net-zero electricity system by 2035. The Discussion Paper invites input on the scope and design for a CES and related issues including, among other things, the level for a CES, the scope of compliance flexibility, and the role of natural gas generation. The Discussion Paper also affirms the Federal Government's intention to collaborate with provinces, territories and stakeholders to ensure the design of the CES provides a clear and workable basis for provinces and territories to be able to plan and operate their electricity systems in a way that will continue to reliably deliver affordable electricity to Canadians.

Capital Power provided comments regarding the Discussion Paper in April 2022. Capital Power's comments highlighted the importance of recognizing a continued role for some natural gas generation in order to support reliability and affordability objectives, though this will vary by province, and the need for the timing and nature of any reasonable CES compliance obligations to differentiate between existing and new generating units, and between baseload and peaking units. The importance of ensuring the design of CES took into account regional differences, particularly Alberta's competitive market framework, was highlighted, along with the need for a CES compliance framework to ensure flexibility to use a full portfolio of approaches, including offsets.

On July 26, ECCC released a Proposed Frame for the Clean Electricity Regulation (the Proposed Frame), setting out the key elements of the potential performance standard framework that ECCC is proposing based on feedback received on the Discussion Paper. The Proposed Frame recognizes the continued role that natural gas generation will have in supporting reliability and integrating renewables through the net-zero electricity supply by 2035 transition and beyond. It would subject new units - defined as those commissioned in 2025 or after - to the CES on January 1, 2035, while existing units would be subject to the CES at the end of their "prescribed life" or January 1, 2035. The definition of prescribed life will be developed as part of continued consultations. The Proposed Frame would allow natural gas units to continue to operate post-prescribed life subject to undefined caps on annual emissions and run-time, and would also subject cogeneration units to the CES in respect of net-to-grid generation.

Based on management's preliminary review of the Draft Frame, Capital Power's entire Alberta natural gas generation fleet, including Genesee 1 and 2 repowering, would qualify as "existing" units, and every unit would only be subject to the CES at the end of its prescribed life or 2035. The Draft Frame's acknowledgement of a long-term role for natural gas generation, including the provisions for post-prescribed life, within a net-zero framework is also notable. Capital Power will review the Proposed Frame in detail and continue to actively participate in ECCC's process to develop the CES framework. ECCC continues to target publishing the draft CES regulation by the end of the fourth quarter of 2022.

In 2022, the Federal Government is also undertaking an assessment of the equivalency of provincial carbon pricing frameworks, including Alberta's Technology, Innovation and Emission Reduction (TIER) framework, with the Federal Output Based Pricing System (OBPS) backstop framework. This review will consider all aspects of Alberta's TIER regime, and not only the TIER electricity regime. The equivalency determination will be made before the end of 2022 and will remain in place until at least 2026, at which time an interim assessment will be made to confirm provincial frameworks continue to meet benchmark criteria for the 2027-30 period. The equivalency review was initiated prior to the launch of the CES consultations, and it is unclear at this time to what extent, if at all, the CES consultations will impact the 2022 equivalency review. As discussed below, Alberta has initiated consultations regarding potential changes to the TIER framework that Alberta expects will maintain equivalency with the Federal backstop framework and preserve provincial jurisdiction over carbon pricing.

On March 29, 2022, the Government of Canada released its inaugural Emissions Reduction Plan (ERP) as required under the *Net Zero Emissions Accountability Act*. The ERP outlined a range of measures the Federal Government is intending to pursue across all sectors to achieve Canada's 2030 emissions reduction commitments. The ERP included the Government's commitment to pursue a net-zero electricity system by 2035. It also included a commitment by the Government to explore measures to de-risk carbon policy, including potential carbon contracts for differences, to provide greater certainty for investments in decarbonizing technology. Such mechanisms could support the Company's consideration and assessment of the Genesee CCS Project and other initiatives.

On April 7, 2022, the Government of Canada tabled Budget 2022. Among the measures included with respect to supporting clean energy deployment, the Government proposed a refundable ITC for investment in CCUS projects. From 2022 – 2030, the proposed ITC rates would be set at 60% for investment in direct air capture projects, 50% for investment in all other CCUS projects, and 37.5% for investment in transportation, storage and use. The rates would be reduced by 50% for the period from 2031 – 2040. The proposed ITC framework is directionally positive for the Genesee CCS Project, though other mechanisms of policy support continue to be required to address certain financing and policy-uncertainty risks and challenges faced by the Project.

Management continues to assess the potential impacts that the proposed elements of the updated CES and the Plan may have for Capital Power's existing facilities and prospective interests in its Canadian markets and intends to participate in forthcoming processes.

Alberta

As discussed in the Company's 2021 Integrated Annual Report, the AESO initiated consultation on the most severe single contingency (MSSC) limit of 466 MW and whether this limit should remain at the current level or increase. The current limit impacts the Genesee repowering project as each combined cycle unit (680 MW) would exceed the current limit. The Company has announced plans to install battery storage in conjunction with the Genesee repowering project to alleviate any constraints the existing MSSC limit may present. In February 2022 the AESO announced that it is developing an options paper on the issue and will present it to stakeholders in September, with consultation occurring through to the end of the year. The Company will be participating in the AESO consultation process and is supportive of the AESO increasing the MSSC limit.

Alberta Environment and Parks (AEP) launched the formal review of the TIER Regulation through a discussion paper released on June 17, 2022. The Discussion Paper noted Alberta's intention to achieve equivalence with the Federal benchmark criteria in order to preserve provincial jurisdiction of the carbon pricing framework for large emitters. The Discussion Paper identified potential changes to various aspects of the TIER framework that, collectively, AEP believes will meet the equivalency threshold as it is being defined by ECCC. The key changes proposed in the Discussion Paper relate to committing Alberta to adopt the Federal carbon price schedule through 2030, introducing a 2% per year reduction to facility-specific and high-performance benchmarks (including the 0.37 t/MWh performance standard of the electricity TIER) until 2030, aligning the Electricity Grid Displacement Factor used as the basis for offsets with the electricity TIER benchmark, and potentially increasing the offset utilization cap from the current level of 60%. Capital Power is assessing the impacts of the proposed changes and will actively engage in AEP's process. AEP is targeting to finalize the recommendations by fall of 2022 and have the enabling regulations completed by December 31, 2022.

United States

Further to the updates outlined in the 2021 Integrated Annual report, 2021 legislatively saw the passage of the Bipartisan Infrastructure Law (Infrastructure Investment and Jobs Act) that puts billions of dollars to work on infrastructure projects across the United States including new energy transmission, CCUS, Direct Air Capture and Hydrogen hub funding opportunities through the Department of Energy.

Legislative deliberations in Congress continue in 2022 regarding clean energy tax credit extensions. Both short- and long-term extension options are being considered that would provide regulatory certainty for renewable energy and low carbon investments. It is understood that discussions are ongoing regarding a reconciliation package that can achieve the necessary 50-vote threshold for passing the Senate. Recent developments have added uncertainty to the prospects for Congressional action on clean energy tax credits and other climate-related measures in the current session.

Trade and supply chain issues remain a regulatory risk for the solar sector. On March 29, 2022, the U.S. Department of Commerce announced that it would open an investigation into whether import taxes were needed for solar panels and key equipment from four Southeast Asian nations – Thailand, Malaysia, Cambodia and Vietnam. The investigation was in response to a February petition from U.S. solar manufacturer Auxin Solar Inc., which alleges that Chinese companies are using the four Southeast Asian nations to circumvent import tariffs. About 80% of the solar panels installed in the U.S. in 2021 came from Thailand, Malaysia, Cambodia and Vietnam. Industry stakeholders pushed back fiercely against the decision with SEIA, American Clean Power, and the American Council on Renewable Energy among the organizations that called on Commerce to immediately issue a negative preliminary decision in the import investigation.

On June 6, the White House announced a series of executive actions designed to reduce uncertainty in the solar supply chain. In the announced action, solar modules and cells sourced from the countries under investigation for possible tariff circumvention – Cambodia, Malaysia, Thailand and Vietnam - can be imported free of certain duties for 24 months. This means that even if new tariffs are assigned to these countries' exports at the conclusion of the circumvention investigation, the solar industry now has certainty that no additional duties will be applied to imports to the United States for the next 24 months, until June 2024.

While the action is a positive development for industry, the coming details will be critical to understand. The U.S. Department of Commerce has been tasked with issuing regulations detailing how this 24 month period will work for importers and exporters alike, and the new rules may not be available until later this summer. Notably, the announcement does not affect the ongoing anti-dumping and countervailing duty investigation, which still carries the risk of new tariffs on solar cells and modules coming to the U.S. from these four countries after this 24 month safe harbor period expires. For that investigation, a preliminary determination is still expected by August and a final ruling in early 2023.

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, 2022 and December 31, 2021 were as follows:

(unaudited, $ millions)		June 30, 2022		December 31, 2021	
	Fair value hierarchy level [1]	**Carrying amount**	**Fair value**	**Carrying amount**	**Fair value**
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	184	184	387	387
Trade and other receivables [2]	N/A	511	511	419	419
Government grant receivable [3]	Level 2	411	367	404	395
Fair value through income or loss					
Derivative financial instruments assets – current and non-current	See below	457	457	313	313
Fair value through other comprehensive income					
Derivative financial instruments assets – current and non-current	See below	102	102	17	17
Financial liabilities:					
Other financial liabilities					
Trade and other payables	N/A	789	789	624	624
Loans and borrowings [3]	Level 2	3,064	2,910	3,360	3,515
Fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See below	605	605	440	440
Fair value through other comprehensive income					
Derivative financial instruments liabilities – current and non-current	See below	137	137	164	164

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 and finance lease receivable.

3 Includes current portion.

Risk management and hedging activities

There have been no material changes in the six months ended June 30, 2022 to the Company's risk management and hedging activities as described in the Company's 2021 Integrated Annual Report.

The derivative financial instruments assets and liabilities held at June 30, 2022 compared with December 31, 2021 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		June 30, 2022					
	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	13	403	88	23	1	528
	Level 3	-	31	-	-	-	31
		13	434	88	23	1	559
Derivative financial instruments liabilities	Level 2	(113)	(293)	(24)	-	-	(430)
	Level 3	-	(312)	-	-	-	(312)
		(113)	(605)	(24)	-	-	(742)
Net derivative financial instruments (liabilities) assets		**(100)**	**(171)**	**64**	**23**	**1**	**(183)**

(unaudited, $ millions)		December 31, 2021				
	Fair value hierarchy level	Commodity cash flow hedges	Commodity non-hedges	Interest rate cash flow hedges	Interest rate non-hedges	Total
Derivative financial instruments assets	Level 2	7	290	10	9	316
	Level 3	-	14	-	-	14
		7	304	10	9	330
Derivative financial instruments liabilities	Level 2	(93)	(241)	(71)	(1)	(406)
	Level 3	-	(198)	-	-	(198)
		(93)	(439)	(71)	(1)	(604)
Net derivative financial instruments (liabilities) assets		**(86)**	**(135)**	**(61)**	**8**	**(274)**

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, 2022 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 2022**	**Mar 2022**	**Dec 2021**	**Sep 2021**	**Jun 2021**	**Mar 2021**	**Dec 2020**	**Sep 2020**
Total generation	6,638	6,893	6,103	6,103	4,975	5,630	6,445	6,327
Alberta commercial facilities[1]								
Genesee 1	733	790	877	824	708	616	807	739
Genesee 2	843	817	259	156	701	581	791	696
Genesee 3	1,010	980	1,006	1,009	951	904	928	1,014
Clover Bar Energy Centre 1, 2 and 3	72	112	135	235	67	23	112	98
Joffre	187	209	136	166	180	203	209	171
Shepard	814	786	714	739	379	803	839	784
Halkirk Wind	124	150	145	98	111	151	150	117
Clover Bar Landfill Gas	3	-	-	-	-	-	-	1
	3,786	3,844	3,272	3,227	3,097	3,281	3,836	3,620
Western Canada contracted facilities[1,2]								
Island Generation	-	7	16	424	114	28	4	47
Quality Wind	70	126	130	101	83	127	128	108
EnPower	4	8	6	-	7	11	8	2
Whitla Wind	349	436	307	156	178	235	258	170
Strathmore Solar[3]	26	3	N/A	N/A	N/A	N/A	N/A	N/A
	449	580	459	681	382	401	398	327
Ontario contracted facilities[2]								
York Energy	6	8	4	6	5	4	3	4
East Windsor	3	3	3	4	4	-	1	2
Goreway	234	599	383	453	159	234	279	329
Kingsbridge 1	23	35	32	13	20	30	36	15
Port Dover and Nanticoke	67	100	81	47	66	81	95	53
	333	745	503	523	254	349	414	403
U.S. contracted facilities								
Roxboro, North Carolina[4]	N/A	N/A	N/A	N/A	N/A	57	81	84
Southport, North Carolina[4]	N/A	N/A	N/A	N/A	N/A	60	95	100
Decatur Energy, Alabama	752	617	789	381	240	356	369	665
Arlington Valley, Arizona	659	476	501	876	461	545	644	693
Beaufort Solar, North Carolina	9	6	6	8	8	6	6	8
Bloom Wind, Kansas	208	180	147	132	177	165	179	154
Macho Springs Wind, New Mexico	48	34	30	15	41	38	30	21
New Frontier Wind, North Dakota	116	122	126	92	93	103	120	95
Cardinal Point Wind, Illinois	167	196	177	93	141	170	170	86
Buckthorn Wind, Texas	111	93	93	75	81	99	103	71
	2,070	1,724	1,869	1,672	1,242	1,599	1,797	1,977

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, as of 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 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, as of January

1, 2021, the British Columbia and Alberta contracted facilities are 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 Strathmore solar was commissioned on March 17, 2022.

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

(%)	Three months ended							
Facility availability	**Jun 2022**	**Mar 2022**	**Dec 2021**	**Sep 2021**	**Jun 2021**	**Mar 2021**	**Dec 2020**	**Sep 2020**
Total average facility availability	92	95	89	91	84	96	97	98
Alberta commercial facilities [1]								
Genesee 1	86	93	100	94	92	92	96	100
Genesee 2	100	95	29	19	100	100	98	100
Genesee 3	100	99	100	99	95	95	93	100
Clover Bar Energy Centre 1, 2 and 3	89	87	83	97	94	99	91	98
Joffre	96	100	82	92	95	100	99	99
Shepard	100	100	99	100	50	100	100	100
Halkirk Wind	98	97	98	96	98	98	97	96
Clover Bar Landfill Gas	74	92	75	24	-	-	-	37
	96	96	84	83	87	97	96	99
Western Canada contracted facilities [1, 2]								
Island Generation	100	100	97	96	89	100	100	100
Quality Wind	98	93	97	96	98	97	97	98
EnPower	99	99	98	100	93	89	98	100
Whitla Wind	97	98	97	95	98	98	99	98
Strathmore Solar [3]	100	100	N/A	N/A	N/A	N/A	N/A	N/A
	99	98	97	96	94	98	99	99
Ontario contracted facilities [2]								
York Energy	100	100	89	87	100	100	100	98
East Windsor	76	97	88	100	100	99	94	99
Goreway	59	100	91	100	89	99	95	93
Kingsbridge 1	99	98	99	99	98	99	100	98
Port Dover and Nanticoke	99	99	97	90	99	99	98	93
	71	99	91	97	93	99	96	94
U.S. contracted facilities								
Roxboro, North Carolina [4]	N/A	N/A	N/A	N/A	N/A	100	100	99
Southport, North Carolina [4]	N/A	N/A	N/A	N/A	N/A	100	99	98
Decatur Energy, Alabama	100	94	82	94	51	79	100	100
Arlington Valley, Arizona	96	78	99	100	78	99	96	99
Beaufort Solar, North Carolina	99	100	98	96	97	99	98	99
Bloom Wind, Kansas	94	94	90	90	98	95	99	95
Macho Springs Wind, New Mexico	98	97	98	97	98	98	98	97
New Frontier Wind, North Dakota	95	96	97	95	97	94	93	97
Cardinal Point Wind, Illinois	98	95	99	96	97	99	97	92
Buckthorn Wind, Texas	90	92	94	96	94	94	96	94
	97	90	91	96	72	90	98	98

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, as of 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 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, as of January 1, 2021, the British Columbia and Alberta contracted facilities are 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 Strathmore solar was commissioned on March 17, 2022.

4 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 2022	**Mar 2022**	**Dec 2021**	**Sep 2021**	**Jun 2021**	**Mar 2021**	**Dec 2020**	**Sep 2020**
Revenues and other income								
Alberta commercial facilities and portfolio optimization[1]	423	456	380	313	314	343	245	274
Western Canada contracted facilities [1,2]	30	50	43	28	25	37	38	29
Ontario contracted facilities [2]	89	104	88	82	66	80	84	70
U.S. contracted facilities	122	104	97	101	86	118	112	133
Corporate [3]	33	32	32	32	32	30	19	13
Unrealized changes in fair value of commodity derivatives and emission credits	16	(245)	32	(179)	(136)	(54)	18	(66)
	713	**501**	**672**	**377**	**387**	**554**	**516**	**453**
Adjusted EBITDA [5]								
Alberta commercial facilities and portfolio optimization[1]	182	192	172	132	136	165	99	131
Western Canada contracted facilities[1, 2]	20	40	34	20	18	29	31	22
Ontario contracted facilities [2,4]	56	65	57	53	49	57	61	52
U.S. contracted facilities	67	53	35	85	35	55	47	96
Corporate	(6)	(2)	(4)	(4)	3	(3)	(18)	(17)
	319	**348**	**294**	**286**	**241**	**303**	**220**	**284**

1 The Genesee 1 and 2 PPAs expired on December 31, 2020 and as a result, as of 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 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, as of January 1, 2021, the British Columbia and Alberta contracted facilities are 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.

5 Adjusted EBITDA is a non-GAAP financial measure (see Non-GAAP Financial Measures and Ratios).

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 2022	**Mar 2022**	**Dec 2021**	**Sep 2021**	**Jun 2021**	**Mar 2021**	**Dec 2020**	**Sep 2020**
Revenues and other income	713	501	672	377	387	554	516	453
Adjusted EBITDA [1, 2,]	319	348	294	286	241	303	220	284
Net income (loss)	77	119	(69)	38	17	101	1	106
Net income (loss) attributable to shareholders of the Company	80	122	(65)	40	20	103	3	108
Basic earnings (loss) per share ($)	0.59	0.96	(0.67)	0.23	0.05	0.83	(0.09)	0.89
Diluted earnings (loss) per share ($)[3]	0.59	0.96	(0.67)	0.23	0.05	0.83	(0.09)	0.89
Normalized earnings per share ($) [1]	0.76	0.93	0.47	0.55	0.32	0.64	0.12	0.66
Net cash flows from operating activities	108	415	185	347	129	206	159	258
Adjusted funds from operations [1]	180	200	149	206	91	159	86	221
Adjusted funds from operations per share ($) [1]	1.55	1.72	1.28	1.78	0.83	1.49	0.81	2.10
Purchase of property, plant and equipment and other assets, net	147	132	198	176	151	97	65	67

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 and Ratios.

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 2022**	**Mar 2022**	**Dec 2021**	**Sep 2021**	**Jun 2021**	**Mar 2021**	**Dec 2020**	**Sep 2020**
Alberta power ($ per MWh)	122	90	107	100	105	95	46	44
Alberta natural gas (AECO) ($ per GJ)	6.86	4.54	4.48	3.32	3.03	3.07	2.52	2.17
Capital Power's Alberta portfolio average realized power price ($ per MWh)	85	84	84	75	75	77	56	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, 2022, the Company recorded net income attributable to shareholders of $122 million compared to net income attributable to shareholders of $103 million for the quarter ended March 31, 2021. Increases in net income were due largely to higher adjusted EBITDA from: our Alberta commercial facilities due to higher generation and higher realized Alberta power prices, higher dispatch at Goreway and wind resource availability at Port Dover and Nanticoke Wind and the commissioning of phases 2 and 3 of Whitla Wind in December 2021. Net finance expense was lower for the quarter ended March 31, 2022 largely due to lower interest on decreased loans and borrowings outstanding. Unrealized losses on commodity derivatives and emission credits were $11 million higher in the first quarter of 2022 due to the impact of increasing forward power prices on Alberta and U.S. net forward sale contracts partially offset by the impact of increasing forward natural gas prices on net forward purchase contracts. Further decreases to net income during the quarter were due to: lower adjusted EBITDA from U.S contracted facilities primarily driven by the impacts of the extreme weather event at Buckthorn Wind in February 2021; higher depreciation expense due to commencement of commercial operations of phases 2 and 3 of Whitla Wind; and higher income tax expense primarily due to higher consolidated net income before tax in the first quarter of 2022.

For the quarter ended December 31, 2021, the Company recorded net loss attributable to shareholders of $65 million compared to net income attributable to shareholders of $3 million for the quarter ended December 31, 2020. Decreases in net income were driven by an impairment loss of $52 million related to the Island Generation facility in the fourth quarter of 2021 compared to 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 of 2021 were $104 million higher than in the fourth quarter of 2020, most notably related to the impact of increasing forward power prices on Alberta and U.S. net forward sale contracts and the impact of decreasing forward natural gas prices on net forward purchase contracts during the fourth quarter of 2021. In addition, net income was reduced compared to the fourth quarter of 2020 by lower adjusted EBITDA from our U.S. contracted facilities, including the impact of the retirement of the Southport and Roxboro facilities, and higher depreciation expense due to accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine. Partially offsetting these operational variances were higher Alberta commercial adjusted EBITDA due largely to higher captured prices and the impacts of the Genesee 1 and 2 PPA expiry, and lower net finance expense.

For the quarter ended September 30, 2021, the Company recorded net income attributable to shareholders of $40 million compared to net income attributable to shareholders of $108 million for the quarter ended September 30, 2020. Decreases in net income were due to: lower adjusted EBITDA from U.S. contracted facilities, including the impact of the retirement of the Southport and Roxboro facilities effective March 31, 2021, unrealized losses on commodity derivatives and emission credits that were $97 million higher than the unrealized gains in the third quarter of 2020 mainly due to the impact of increasing forward prices on Alberta and U.S. power net forward sale contracts, partially offset by the impact of increasing forward prices on natural gas net forward purchase contracts; and higher depreciation expense due to accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine. These decreases were partially offset by $31 million of gains on disposals and other transactions including insurance recoveries, net of related expenses to repair Genesee 2 and a gain on decommissioning of the Southport and Roxboro facilities to reflect lower than expected decommissioning costs. Lastly, income tax expense was lower in the third quarter of 2021 primarily due to lower consolidated income before tax.

For the quarter ended June 30, 2021, the Company recorded net income attributable to shareholders of $20 million compared to net income attributable to shareholders of $23 million for the quarter ended June 30, 2020. Decreases in net income were due to: lower adjusted EBITDA from U.S. contracted facilities primarily due to the retirement of the Southport and Roxboro facilities effective March 31, 2021 and the impacts of the strengthening Canadian dollar; unrealized losses on commodity derivatives and emission credits that were $15 million higher than in the second quarter of 2020 mainly due to the impact of increasing forward prices on U.S. power forward sale contracts, partially offset by unrealized gains on natural gas net forward purchase contracts; higher depreciation expense due to accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine; and unrealized foreign exchange losses on outstanding foreign currency non-hedge sale contracts transacted during the second quarter of 2021. These decreases were largely offset by 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 and the accelerated recognition of off-coal compensation.

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 off-coal compensation, 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 sale 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 sale 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, higher depreciation expense due to accelerated depreciation of Genesee 1 and 2 coal assets and the Genesee Mine, and the 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 off-coal compensation 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 emission 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 phase 1 of Whitla Wind 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 phase 1 of Whitla Wind 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.

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 2022	**Mar 2022**	**Dec 2021**	**Sep 2021**	**Jun 2021**	**Mar 2021**	**Dec 2020**	**Sep 2020**
Share price ($/common share)								
High	46.51	41.98	45.05	45.04	42.28	38.34	36.47	30.28
Low	40.48	36.35	37.95	39.99	36.22	33.31	29.13	26.57
Close	45.01	40.71	39.46	42.71	40.95	36.40	34.98	29.39
Volume of shares traded (millions)	19.9	21.6	15.8	13.4	21.3	22.9	20.2	21.6

Outstanding share and partnership unit data

At July 27, 2022, the Company had 116.470 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), 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 at July 27, 2022 were 118.602 million. The outstanding special limited voting share is held by EPCOR.

At July 27, 2022, CPLP had 90.742 million general partnership units outstanding and 337.733 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, 2022 and 2021

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Six months ended June 30, 2022 and 2021

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, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Revenues	$ 657	$ 332	$ 1,103	$ 828
Other income	56	55	111	113
Energy purchases and fuel	(313)	(67)	(387)	(216)
Gross margin	400	320	827	725
Other raw materials and operating charges	(40)	(46)	(73)	(82)
Staff costs and employee benefits expense	(44)	(40)	(86)	(91)
Depreciation and amortization	(139)	(132)	(281)	(269)
Impairment reversal	-	2	-	2
Other administrative expense	(32)	(23)	(61)	(51)
Foreign exchange loss	(7)	(2)	(6)	(1)
Operating income	138	79	320	233
Losses on disposals and other transactions	(1)	(3)	(1)	(1)
Net finance expense	(35)	(46)	(72)	(87)
Income from joint venture	6	1	13	7
Income before tax	108	31	260	152
Income tax expense (note 3)	(31)	(14)	(64)	(34)
Net income	$ 77	$ 17	$ 196	$ 118
Attributable to:				
Non-controlling interests	$ (3)	$ (3)	$ (6)	$ (5)
Shareholders of the Company	$ 80	$ 20	$ 202	$ 123
Earnings per share (attributable to common shareholders of the Company):				
Basic (note 4)	$ 0.59	$ 0.05	$ 1.56	$ 0.88
Diluted (note 4)	$ 0.59	$ 0.05	$ 1.55	$ 0.87

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Net income	$ 77	$ 17	$ 196	$ 118
Other comprehensive income (loss):				
Items that will not be reclassified subsequently to net income:				
Defined benefit plans:				
Actuarial gains[1]	10	-	10	-
Items that are or may be reclassified subsequently to net income:				
Cash flow hedges:				
Unrealized (losses) on derivative instruments[2]	(61)	(99)	(2)	(106)
Reclassification of losses on derivative instruments to income for the period[3]	47	50	52	86
Net investment in foreign subsidiaries:				
Unrealized gains (losses)[4]	34	(5)	23	(18)
Total items that are or may be reclassified subsequently to net income, net of tax	20	(54)	73	(38)
Total other comprehensive income (loss), net of tax	30	(54)	83	(38)
Total comprehensive income (loss)	$ 107	$ (37)	$ 279	$ 80
Attributable to:				
Non-controlling interests	$ (3)	$ (3)	$ (6)	$ (5)
Shareholders of the Company	$ 110	$ (34)	$ 285	$ 85

1 For the three and six months ended June 30, 2022, net of income tax expense of $3. For the three and six months ended June 30, 2021, net of income tax expense of nil.

2 For the three and six months ended June 30, 2022, net of income tax recoveries of $18 and nil, respectively. For the three and six months ended June 30, 2021, net of income tax recoveries of $32 and $33, respectively.

3 For the three and six months ended June 30, 2022, net of reclassification of income tax recoveries of $14 and $16, respectively. For the three and six months ended June 30, 2021, net of reclassification of income tax recoveries of $17 and $27, respectively.

4 For the three and six months ended June 30, 2022 and 2021, net of income tax expense of nil.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	June 30, 2022	December 31, 2021
Assets		
Current assets:		
Cash and cash equivalents	$ 184	$ 387
Trade and other receivables	573	474
Inventories	210	217
Derivative financial instruments assets (note 5)	182	108
	1,149	1,186
Non-current assets:		
Other assets	48	47
Derivative financial instruments assets (note 5)	377	222
Finance lease receivable (note 6)	38	-
Government grant receivable	354	349
Deferred tax assets	14	17
Equity-accounted investments	157	145
Right-of-use assets	120	120
Intangible assets and goodwill	759	784
Property, plant and equipment	6,139	6,203
Total assets	$ 9,155	$ 9,073
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 789	$ 624
Derivative financial instruments liabilities (note 5)	330	252
Loans and borrowings	126	126
Deferred revenue and other liabilities	149	153
Provisions	42	50
	1,436	1,205
Non-current liabilities:		
Derivative financial instruments liabilities (note 5)	412	352
Loans and borrowings	2,938	3,234
Lease liabilities	139	137
Deferred revenue and other liabilities	282	291
Deferred tax liabilities	639	584
Provisions	313	411
	4,723	5,009
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 7)	3,638	3,631
Deficit	(617)	(671)
Other reserves	(36)	(119)
Deficit and other reserves	(653)	(790)
	2,985	2,841
Non-controlling interests	11	18
Total equity	2,996	2,859
Total liabilities and equity	$ 9,155	$ 9,073

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 7)	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, 2022	$ 3,631	$ (84)	$ (28)	$ (17)	$ 10	$ (671)	$ 2,841	$ 18	$ 2,859
Net income	-	-	-	-	-	202	202	(6)	196
Other comprehensive income (loss):									
Defined benefit plan actuarial gain	-	-	-	13	-	-	13	-	13
Cash flow derivative hedge losses	-	(2)	-	-	-	-	(2)	-	(2)
Reclassification of losses to net income	-	68	-	-	-	-	68	-	68
Unrealized gains on foreign currency translation	-	-	23	-	-	-	23	-	23
Tax on items recognized directly in equity	-	(16)	-	(3)	-	-	(19)	-	(19)
Other comprehensive income	$ -	$ 50	$ 23	$ 10	$ -	$ -	$ 83	$ -	$ 83
Total comprehensive income (loss)	-	50	23	10	-	202	285	(6)	279
Distributions to non-controlling interests	-	-	-	-	-	-	-	(1)	(1)
Common share dividends (note 7)	-	-	-	-	-	(127)	(127)	-	(127)
Preferred share dividends (note 7)	-	-	-	-	-	(20)	(20)	-	(20)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Share options exercised	7	-	-	-	-	-	7	-	7
Equity as at June 30, 2022	$ 3,638	$ (34)	$ (5)	$ (7)	$ 10	$ (617)	$ 2,985	$ 11	$ 2,996

[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 7)	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	-	(139)	-	-	-	-	(139)	-	(139)
Reclassification of losses to net income	-	113	-	-	-	-	113	-	113
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 7)	-	-	-	-	-	(114)	(114)	-	(114)
Preferred share dividends (note 7)	-	-	-	-	-	(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 Cash Flows
(Unaudited, in millions of Canadian dollars)

	Six months ended June 30, 2022	2021
Cash flows from operating activities:		
Net income	$ 196	$ 118
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Impairment reversal	-	(2)
Depreciation and amortization	281	269
Net finance expense	72	87
Fair value changes on commodity derivative instruments and emission credits held for trading	46	31
Foreign exchange losses	6	1
Income tax expense	64	34
Income from joint venture	(13)	(7)
Recognition of government grant deferred revenue	(63)	(63)
Tax equity attributes	(45)	(47)
Other items	13	9
Change in fair value of derivative instruments reflected as cash settlement	(45)	(11)
Distributions received from joint venture	2	5
Interest paid	(54)	(61)
Income taxes paid	(17)	(5)
Other cash items	(25)	(8)
Change in non-cash operating working capital	105	(15)
Net cash flows from operating activities	523	335
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets, net[1]	(279)	(248)
Other cash flows from investing activities	-	7
Net cash flows used in investing activities	(279)	(241)
Cash flows used in financing activities:		
Repayment of loans and borrowings	(280)	(503)
Repayment of lease liabilities	(2)	(3)
Issue of shares	-	288
Share issue costs	-	(12)
Proceeds from exercise of share options	7	15
Dividends paid (note 7)	(148)	(105)
Capitalized interest paid	(7)	(3)
Distributions to non-controlling interests	(1)	-
Income taxes paid on preferred share dividends	(8)	(5)
Net cash flows used in financing activities	(439)	(328)
Foreign exchange (loss) gain on cash held in foreign currency	(8)	5
Net decrease in cash and cash equivalents	(203)	(229)
Cash and cash equivalents at beginning of period	387	367
Cash and cash equivalents at end of period	$ 184	$ 138

[1] Reflects total additions for the six months ended June 30, 2022, reduced by $40 million for changes in non-cash investing working capital and other non-current liabilities (six months ended June 30, 2021 – reduced by $65 million), to arrive at cash additions of property, plant and equipment and other assets.

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 2021 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, 2022.

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,	
	2022	2021	2022	2021
Income before tax	$ 108	$ 31	$ 260	$ 152
Income tax at the statutory rate of 23%	25	7	60	35
Increase (decrease) resulting from:				
Non-deductible amounts	4	5	3	4
Amounts attributable to non-controlling interests and tax-equity interests	-	5	1	8
Change in unrecognized tax benefits	2	-	1	-
Statutory and other rate differences	1	(4)	(1)	(14)
Other	(1)	1	-	1
Income tax expense	$ 31	$ 14	$ 64	$ 34

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

4. Earnings per share:

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

	Three months ended June 30,		Six months ended June 30,	
	2022	2021	2022	2021
Income for the period attributable to shareholders	$ 80	$ 20	$ 202	$ 123
Preferred share dividends[1]	(11)	(14)	(21)	(28)
Earnings available to common shareholders	$ 69	$ 6	$ 181	$ 95
Weighted average number of common shares	116,398,934	109,730,029	116,310,808	108,283,457
Basic earnings per share	$ 0.59	$ 0.05	$ 1.56	$ 0.88
Weighted average number of common shares	116,398,934	109,730,029	116,310,808	108,283,457
Effect of dilutive share purchase options	747,853	767,000	701,566	715,715
Diluted weighted average number of common shares	117,146,787	110,497,029	117,012,374	108,999,172
Diluted earnings per share	$ 0.59	$ 0.05	$ 1.55	$ 0.87

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

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, 2022					
	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	$ 10	$ 125	$ 37	$ 9	$ 1	$ 182
Non-current	3	309	51	14	-	377
Derivative instruments liabilities:						
Current	(91)	(229)	(10)	-	-	(330)
Non-current	(22)	(376)	(14)	-	-	(412)
Net fair value	$ (100)	$ (171)	$ 64	$ 23	$ 1	$ (183)
Net notional (sells) buys (millions):						
Megawatt hours of electricity	(6)	(31)				
Gigajoules of natural gas purchased[1]		96				
Gigajoules of natural gas basis swaps[1]		99				
Metric tonnes of emission allowances		3				
Number of renewable energy credits		(12)				
Interest rate swaps			$ 1,526	$ 230		
Forward currency buys (U.S. dollars)					$ 19	
Range of remaining contract terms in years	0.1 to 4.5	0.1 to 24.6	0.2 to 4.6	0.9 to 1.4	0.1 to 0.2	

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

5. Derivative financial instruments and hedge accounting, continued:

[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.

	December 31, 2021				
	Energy and emission allowances		Interest rate		
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 5	$ 94	$ -	$ 9	$ 108
Non-current	2	210	10	-	222
Derivative instruments liabilities:					
Current	(72)	(149)	(31)	-	(252)
Non-current	(21)	(290)	(40)	(1)	(352)
Net fair value	$ (86)	$ (135)	$ (61)	$ 8	$ (274)
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(5)	(26)			
Gigajoules of natural gas purchased[2]		129			
Gigajoules of natural gas basis swaps[2]		128			
Number of renewable energy credits		(8)			
Interest rate swaps			$ 1,501	$ 80	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 25.1	0.7 to 5.1	1.4 to 1.9	

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

Fair values of derivative instruments are determined using valuation techniques, inputs, and assumptions as described in the Company’s 2021 annual consolidated financial statements. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

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

	Three months ended June 30, 2022		Three months ended June 30, 2021	
	Unrealized (losses) gains	Realized losses	Unrealized (losses) gains	Realized (losses) gains
Energy cash flow hedges	$ (71)	$ (60)	$ (42)	$ (67)
Energy and emission allowances non-hedges	(27)	(50)	(22)	2
Interest rate cash flow hedges[3]	52	(1)	(28)	-
Interest rate non-hedges	6	-	(1)	-
Foreign exchange cash flow hedges	1	-	6	-
Foreign exchange non-hedges	(1)	(1)	(8)	6

(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, 2022		Six months ended June 30, 2021	
	Unrealized (losses) gains	Realized losses	Unrealized (losses) gains	Realized (losses) gains
Energy cash flow hedges	$ (53)	$ (65)	$ (53)	$ (111)
Energy and emission allowances non-hedges	(41)	(47)	(32)	(8)
Interest rate cash flow hedges[3]	118	(3)	22	(2)
Interest rate non-hedges	14	-	9	-
Foreign exchange cash flow hedges	1	-	5	-
Foreign exchange non-hedges	-	(1)	(6)	5

[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 was 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.

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, 2022 and 2021:

	Three months ended June 30,		Six months ended June 30,	
	2022	2021	2022	2021
Revenues	$ (212)	$ (271)	$ (497)	$ (434)
Energy purchases and fuel	75	184	344	283
Foreign exchange loss	(2)	(2)	(1)	(1)
Net finance expense	5	(1)	11	7

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, 2022, the amount realized within net finance expense pertaining to the ineffective portion of hedging derivatives was nil (three and six months ended June 30, 2021 – $2 million of gains).

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, 2022
Within one year	$ (106)
Between one and five years	21
After five years	39
	$ (46)

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

6. Finance lease receivable

In May 2022, Capital Power executed a 4.5-year energy purchase agreement (EPA) for its Island Generation facility with BC Hydro, effective May 2022 through to October 2026. The new EPA is classified as a finance lease, whereas the previous EPA which expired in April 2022 was classified as an operating lease. Accordingly, during the second quarter of 2022, Capital Power derecognized Island Generation's net assets that were previously presented within property, plant and equipment on the consolidated statements of financial position and recognized a corresponding finance lease receivable, with the current portion included within trade and other receivables. The new EPA is subject to regulatory approval by the British Columbia Utilities Commission.

Finance income of $2 million was recognized in revenues for the three and the six months ended June 30, 2022.

The following table sets out the maturity analysis of the lease receivable, showing the minimum undiscounted lease payments to be received:

	June 30, 2022
Amounts receivable under finance lease:	
Less than one year	$ 19
Between one and five years	59
Total undiscounted lease receivable	78
Unearned finance income	(35)
Net investment in lease	43
Less: current portion[1]	(5)
	$ 38

[1] Included within trade and other receivables

7. Share capital:

	Dividends declared							
	For the three months ended June 30,				For the six months ended June 30,			
	2022		2021		2022		2021	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.5475	$ 63	$ 0.5125	$ 59	$ 1.0950	$ 127	$ 1.0250	$114
Preference								
Series 1	0.1638	1	0.1638	1	0.3276	2	0.3276	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[1]	-	-	0.3750	3	-	-	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

[1] On December 31, 2021, the Company redeemed all of its 8 million issued and outstanding 6.00% cumulative rate reset preference shares, Series 7.

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

7. Share capital, continued:

	Dividends paid[2]							
	For the three months ended June 30,				For the six months ended June 30,			
	2022		2021		2022		2021	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common[3]	$ 0.5475	$ 64	$ 0.5125	$ 55	$ 1.0950	$ 128	$ 1.0250	$109

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

[3] For the three and six months ended June 30, 2022, all common dividends were paid in cash.

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.

During the three and six months ended June 30, 2022 and 2021, the Company did not purchase and cancel any of its outstanding common shares under its Toronto Stock Exchange approved normal course issuer bid.

In March 2022, the Toronto Stock Exchange approved the Company's normal course issuer bid to purchase and cancel up to 8 million of its outstanding common shares during the one-year period from February 28, 2022 to February 27, 2023.

8. 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 2021 annual consolidated financial statements. Due to the short-term nature of the financial instruments, the fair values are not materially different from their carrying amounts.

The fair values of the Company's other long-term financial instruments are determined using the same valuation techniques, inputs, and assumptions as described in the Company's 2021 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, 2022		December 31, 2021	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets[1]					
Government grant receivable	Level 2	$ 411	$ 367	$ 404	$ 395
Financial liabilities[1]					
Loans and borrowings	Level 2	$ 3,064	$ 2,910	$ 3,360	$ 3,515

[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 at December 31, 2021.

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

8. Financial instruments, continued:

Fair value hierarchy, continued

The fair value measurement of a financial instrument is included in only one of the three levels described in the Company's 2021 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. There were no transfers between levels in the fair value hierarchy for the six months ended June 30, 2022 and the year ended December 31, 2021.

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 2021 annual consolidated financial statements.

	June 30, 2022			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 528	$ 31	$ 559
Derivative financial instruments liabilities	-	(430)	(312)	(742)

	December 31, 2021			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 316	$ 14	$ 330
Derivative financial instruments liabilities	-	(406)	(198)	(604)

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, this 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 4 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.

The Company has a 10-year renewable energy agreement for Whitla Wind, a 15-year fixed price contract for Enchant Solar and a 25-year fixed price contract for Strathmore Solar, expiring in 2032, 2037 and 2047, respectively, to generate renewable generation and deliver environmental attributes. Observable forward market prices are not available for the full terms of the contracts and notional quantities used to calculate fair value reflect anticipated generation, therefore pricing and generation forecasts have been developed based on internal modelling. Accordingly, these financial instruments are classified as Level 3.

In addition, at June 30, 2022 and December 31, 2021, the Company holds contracts for the sale of renewable energy credits for which pricing beyond two years is not readily observable and the contracts are therefore classified in Level 3 of the hierarchy.

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

8. Financial instruments, continued:

Fair value hierarchy, continued

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, 2022	December 31, 2021
REC pricing (per certificate) – Solar	$2.75 to $323.21	$2.96 to $352.48
REC pricing (per certificate) – Wind	$2.17 to $4.60	$2.07 to $4.18
Forward power pricing (per MWh) – Solar	$40.24 to $135.00	$35.32 to $113.86
Forward power pricing (per MWh) – Wind	$27.01 to $172.18	$25.25 to $88.42
Average monthly generation (MWh) – Strathmore Solar	7,122	7,123
Average monthly generation (MWh) – Enchant Solar	6,905	6,905
Average monthly generation (MWh) – Whitla Wind	41,473	N/A
Average monthly generation (MWh) – Bloom Wind	58,944	59,067
Average monthly generation (MWh) – Buckthorn Wind	17,627	17,702

Valuation process applied to Level 3

The valuation models used to calculate the fair values of the derivative financial instrument 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 increase or decrease to fair value of Level 3 derivative instruments based on a 10% decrease or increase in the respective input:

	June 30, 2022	December 31, 2021
REC pricing – Solar	$ (1)	$ -
REC pricing – Wind	2	1
Forward power pricing – Solar	15	16
Forward power pricing – Wind	69	31
Generation – Solar	3	1
Generation – Wind	17	14

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, 2022	December 31, 2021
At January 1[2]	$ (184)	$ 35
Unrealized and realized losses included in net income[3]	(110)	(211)
Settlements[4]	18	(6)
Foreign exchange losses	(5)	(2)
At end of period	$ (281)	$ (184)
Total unrealized and realized losses for the period included in net income[3]	$ (110)	$ (211)

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

[3] Recorded in revenues.

[4] Relates to settlement of financial derivative instruments.

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

8. Financial instruments, continued:

Fair value hierarchy, continued

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.

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, 2022				Three months ended June 30, 2021			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues – external[1]	$ 544	$ 113	$ -	$ 657	$ 392	$ (60)	$ -	$ 332
Revenues – inter-area	(59)	66	(7)	-	8	-	(8)	-
Other income	33	23	-	56	33	22	-	55
Total revenues and other income	$ 518	$ 202	$ (7)	$ 713	$ 433	$ (38)	$ (8)	$ 387

	Six months ended June 30, 2022				Six months ended June 30, 2021			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues – external[1]	$ 1,149	$ (46)	$ -	$ 1,103	$ 844	$ (16)	$ -	$ 828
Revenues – inter-area	(65)	77	(12)	-	13	-	(13)	-
Other income	66	45	-	111	66	47	-	113
Total revenues and other income	$ 1,150	$ 76	$ (12)	$ 1,214	$ 923	$ 31	$ (13)	$ 941

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

	At June 30, 2022			At December 31, 2021		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 4,562	$ 1,577	$ 6,139	$ 4,603	$ 1,600	$ 6,203
Right-of-use assets	57	63	120	56	64	120
Intangible assets and goodwill	625	134	759	645	139	784
Finance lease receivable[2] (note 6)	43	-	43	-	-	-
Other assets	48	-	48	47	-	47
	$ 5,335	$ 1,774	$ 7,109	$ 5,351	$ 1,803	$ 7,154

[2] Includes current portion.

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

9. Segment information, continued:

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

	Three months ended June 30, 2022						
	Alberta Commercial	Western Canada Contracted	Ontario Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 552	$ 34	$ 88	$ 82	$ 756	$ (117)	$ 639
Emission credit revenues	7	1	-	-	8	10	18
Total revenues[3]	$ 559	$ 35	$ 88	$ 82	$ 764	(107)	$ 657

	Six months ended June 30, 2022						
	Alberta Commercial	Western Canada Contracted	Ontario Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 1,002	$ 71	$ 186	$ 135	$ 1,394	$ (334)	$ 1,060
Emission credit revenues	14	4	-	3	21	22	43
Total revenues[3]	$ 1,016	$ 75	$ 186	$ 138	$ 1,415	(312)	$ 1,103

	Three months ended June 30, 2021						
	Alberta Commercial	Western Canada Contracted	Ontario Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 416	$ 16	$ 65	$ 36	$ 533	$ (209)	$ 324
Emission credit revenues	6	1	-	-	7	1	8
Total revenues[3]	$ 422	$ 17	$ 65	$ 36	$ 540	(208)	$ 332

	Six months ended June 30, 2021						
	Alberta Commercial	Western Canada Contracted	Ontario Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 806	$ 41	$ 140	$ 120	$ 1,107	$ (292)	$ 815
Emission credit revenues	13	3	-	2	18	(5)	13
Total revenues[3]	$ 819	$ 44	$ 140	$ 122	$ 1,125	(297)	$ 828

[3] Included within trade and other receivables, at June 30, 2022, were amounts related to contracts with customers of $308 million (2021 - $257 million).

10. Subsequent events:

Dividend increase

On July 29, 2022, the Company's Board of Directors approved an increase of 6% in the annual dividend for holders of its common shares, from $2.19 per common share to $2.32 per common share. This increased common share dividend will commence with the third quarter 2022 quarterly dividend payment on October 31, 2022 to shareholders of record at the close of business on September 30, 2022.

Acquisition of Midland Cogeneration Venture

On July 12, 2022, Capital Power announced its partnership with Manulife Investment Management on behalf of the Manulife Infrastructure Fund II (Manulife) and its affiliates to acquire 100% of the interests in MCV Holding Company, which owns Midland Cogeneration Venture (Midland Cogen), a 1,633 MW natural gas combined-cycle cogeneration facility. Midland Cogen is being acquired from OMERS Infrastructure Management Inc and its co-investors and is expected to close in the third quarter of 2022, subject to regulatory approvals and other customary closing conditions.

The purchase price for the natural gas combined-cycle cogeneration facility consists of a total purchase price of $1,163 million (US$894 million), including the assumption of $678 million (US$521 million) of project level debt. Capital Power and Manulife Investment Management will each own a 50% interest in MCV Holdings Company and will each contribute approximately $242 million (US$186 million) subject to working capital and other closing adjustments. Capital Power will finance its share of the transaction using cash on hand and its existing credit facilities. Capital Power will be responsible for operations and maintenance and asset management for which it will receive an annual management fee.

11. Comparative figures:

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