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For release: July 25, 2016

Capital Power reports second quarter 2016 results and announces a 6.8% dividend increase for its common shares

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released financial results for the second quarter ended June 30, 2016. The Company also announced that its Board of Directors approved a 6.8% dividend increase for its common shares. Accordingly, effective for the third quarter 2016 dividend payment, the quarterly dividend will increase from $0.365 to $0.39 per common share, representing an annualized dividend of $1.56 per common share.

Net income (loss) attributable to shareholders in the second quarter of 2016 was $23 million and basic earnings (loss) per share attributable to common shareholders was $0.19 per share, compared with $(34) million, or $(0.39) per share, in the comparable period of 2015. Normalized earnings attributable to common shareholders in the second quarter of 2016, after adjusting for one-time items and fair value adjustments, were $29 million or $0.30 per share compared with $10 million or $0.10 per share in the second quarter of 2015.

Net cash flows from operating activities were $70 million in the second quarter of 2016 compared with $14 million in the second quarter of 2015. Funds from operations were $106 million in the second quarter of 2016, up 51%, on a comparable basis, from $70 million in the second quarter of 2015.

For the six months ended June 30, 2016, net income attributable to shareholders was $17 million and basic earnings (loss) per share attributable to common shareholders was $0.07 per share compared with $6 million and $(0.06) for the six months ended June 30, 2015. Net cash flows from operating activities were $201 million for the six months ended June 30, 2016 compared with $121 million for the six months ended June 30, 2015.

For the six months ended June 30, 2016, normalized earnings attributable to common shareholders were $61 million, or $0.63 per share, compared with $37 million, or $0.40 per share, in the first six months of 2015. Funds from operations totaled $215 million compared with $178 million in the comparable six month period last year.

“Capital Power’s second quarter financial performance exceeded management’s expectations,” said Brian Vaasjo, President and CEO of Capital Power. “We continue to see the benefits of strong portfolio optimization activities that contributed to the strong quarterly results. Our trading desk captured an average realized Alberta power price of $61 per megawatt hour (MWh) in the second quarter, well above the average spot price of $15 per MWh that primarily reflected excess supply in the market, low natural gas prices, and conservative offer strategies from market participants. In addition, our Alberta contracted assets delivered favourable results in the quarter driven by savings during the Genesee 2 major maintenance outage due to a shorter than anticipated outage as well as lower than anticipated outage costs.”

“Normalized earnings of $0.30 per share in the second quarter were significantly higher than the $0.10 per share a year ago. We generated strong funds from operations of $106 million in the second quarter, a 51% increase from the same period a year ago. With $215 million in funds from operations generated in the first half of the 2016 and based on our outlook for the remainder of the year, we remain on track to meet our $380 to $430 million annual financial target range,” said Mr. Vaasjo.

“Based on Capital Power’s projected cash flows and consistent with our 7% annual dividend growth guidance that was discussed at our December 2015 Investor Day, I am pleased to announce that the Board of Directors has approved a 6.8% or $0.10 per share increase to an annual dividend of $1.56 per share effective with the third quarter 2016 quarterly dividend payment.”

“We continue to be engaged with the Alberta government to ensure fair compensation is received for the proposed accelerated closure of coal-fired generating units by 2030 under the Alberta government’s Climate Leadership Plan,” added Mr. Vaasjo. “Discussions with the government-appointed facilitator are on-going and we remain optimistic that a fair and appropriate outcome will be reached for our shareholders. We expect the Alberta government will provide more details on the implementation of their Climate Leadership Plan in the third and fourth quarters of this year.”

Operational and Financial Highlights [1] (unaudited)	**Three months ended June 30**		**Six months ended June 30**	
(millions of dollars except per share and operational amounts)	**2016**	**2015**	**2016**	**2015**
Electricity generation (excluding Sundance power purchase arrangement (PPA)) (GWh)	3,707	3,553	7,605	6,951
Generation plant availability (excluding Sundance PPA) (%)	90%	90%	93%	94%
Revenues	$ 229	$ 83	$ 570	$ 441
Adjusted EBITDA [2]	$ 108	$ 47	$ 228	$ 194
Net income (loss)	$ 20	$ (48)	$ 12	$ 2
Net income (loss) attributable to shareholders of the Company	$ 23	$ (34)	$ 17	$ 6
Basic and diluted earnings (loss) per share	$ 0.19	$ (0.39)	$ 0.07	$ (0.06)
Normalized earnings attributable to common shareholders [2]	$ 29	$ 10	$ 61	$ 37
Normalized earnings per share [2]	$ 0.30	$ 0.10	$ 0.63	$ 0.40
Net cash flows from operating activities	$ 70	$ 14	$ 201	$ 121
Funds from operations [2]	$ 106	$ 70	$ 215	$ 178
Purchase of property, plant and equipment and other assets	$ 81	$ 35	$ 112	$ 87
Dividends per common share, declared	$ 0.3650	$ 0.3400	$ 0.7300	$ 0.6800

[1] The operational and financial highlights in this press release should be read in conjunction with Management’s Discussion and Analysis and the unaudited Condensed Interim Consolidated Financial Statements for the six months ended June 30, 2016.

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

Significant Events

Completion of contract for output for Bloom Wind

On April 25, 2016, Capital Power announced that construction of its Bloom Wind project (Bloom Wind) is expected to commence in the third quarter of 2016. Bloom Wind is a 178 megawatt (MW) facility in southwestern Kansas consisting of 54 3.3 MW turbines and is anticipated to cost $358 million (US$272 million). Commercial operation of the facility is expected in the third quarter of 2017. Capital Power will operate Bloom Wind under a 10-year fixed price contract with Allianz Risk Transfer (rated AA- stable by Standard & Poor's), a subsidiary of Allianz SE, the worldwide insurance and asset management group, covering 100% of the project's output. Under the contract, which was executed on April 21, 2016, Capital Power will swap the market revenue of the project's generation for a fixed annual payment for a 10-year term. The agreement will secure long-term predictable revenues and mitigate generation volume uncertainty related to wind resources, allowing Bloom Wind to secure renewable energy tax equity financing and provide Capital Power the opportunity to complete its first wind development project in the growing U.S. renewables market.

Approval of normal course issuer bid

On April 25, 2016, Capital Power announced that the Toronto Stock Exchange (TSX) approved the Company's normal course issuer bid (NCIB) to purchase and cancel up to 8.6 million of its outstanding common shares during the one year period from April 28, 2016 to April 27, 2017. Capital Power purchased and cancelled 7.1 million common shares under its prior NCIB approved by the TSX on March 25, 2015 for the period from April 7, 2015 to April 6, 2016, but has not yet purchased and cancelled any common shares under the NCIB approved on April 25, 2016.

Termination of the Sundance PPA

On March 24, 2016, Capital Power notified the Balancing Pool of the Company's decision to terminate its role as Buyer of the Sundance PPA effective March 24, 2016. Capital Power exercised its right to terminate the Sundance PPA under the Change in Law provisions of the arrangement, following changes to the Specified Gas Emitters Regulation (SGER) that took effect at the start of 2016. As a result of this termination, no further economic benefits are expected from the Sundance PPA and the related intangible asset was derecognized. The Company has recorded a non-cash pre-tax loss of $53 million ($46 million post-tax) with respect to the derecognition of the Sundance PPA asset. The Balancing Pool and Capital Power could differ in opinion as to the effective termination date.

Climate Leadership Plan (CLP) Update

On March 16, 2016, the Alberta government appointed a Facilitator to oversee the transition away from coal-fired generation in Alberta by 2030. The Facilitator's background is with large public power providers and centrally dispatched power systems and advising energy leaders in numerous countries around the world. The Facilitator's mandate is to provide options and preferred approaches to the Alberta government to phase out emissions from coal-fired generation by 2030 that will maintain the reliability of Alberta's electricity grid and price stability for consumers while preventing unnecessarily stranding capital assets. Throughout this process, the Alberta government has indicated that it intends to ensure that affected workers, communities and companies are treated fairly. It is expected that the Facilitator will report to the Alberta government on this mandate in the latter half of 2016. Capital Power is participating in the Facilitator process to ensure that fair compensation is received for the proposed accelerated closure of the Company's coal facilities.

On January 26, 2016, the Alberta government tasked the Alberta Electric System Operator (AESO) to develop and implement a plan to bring on new renewable electricity generation capacity to the grid by 2030 in connection with the CLP. The Alberta government mandated that the process must be carefully managed and operate in concert with the retirement of the current coal generating units. The Alberta government also confirmed that it has not chosen to fundamentally alter the current wholesale electricity market structure. The AESO undertook a process to receive industry perspectives regarding various elements of the Renewable Energy Program (REP), and provided its recommendations regarding the REP to the Alberta government on May 31, 2016. The recommendations have not been made public. It is currently expected that the Alberta government will provide direction on the REP by the third quarter of 2016, and the AESO currently expects to initiate the process for the first procurement by year-end.

As of July 22, 2016, the Alberta government has yet to initiate formal consultations relating to the Carbon Competitiveness Regulation (CCR Regulation). The CCR Regulation will establish the performance standard and carbon pricing framework that will apply to facilities that are currently subject to the Specified Gas Emitters Regulation (SGER), and will replace SGER effective January 1, 2018. The CLP provided general direction that the performance standard for the electricity sector will be based on the emissions performance of the cleanest natural gas-fired facility in Alberta, with specific details to be developed through consultation.

Preferred Shares (Series 1) dividend rate reset

On February 18, 2016 the Board of Directors of Capital Power declared a quarterly dividend of $0.19125 per share on the Company's Cumulative 5-Year Rate Reset Preference Shares, Series 1 (Series 1 Shares). This quarterly dividend was paid on March 31, 2016. The Annual Fixed Dividend Rate for the Series 1 Shares for the next five year period was reset from 4.60% to 3.06% on December 31, 2015 at a rate equal to the sum of the then Government of Canada bond yield and 2.17%. The Annual Fixed Dividend Rate will be next reset on December 31, 2020 and every five years thereafter.

Subsequent Event

On July 25, 2016 the Company announced that its Board of Directors approved a 6.8% increase in the annual dividend for holders of its common shares, from $1.46 per common share to $1.56 per common share. This increased common dividend will commence with the third quarter 2016 quarterly dividend payment payable on October 31, 2016 to shareholders of record at the close of business on September 30, 2016.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on July 25, 2016 at 9:00 am (MDT) to discuss the second quarter financial results. The conference call dial-in numbers are:

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

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

Non-GAAP Financial Measures

The Company uses (i) adjusted EBITDA, (ii) funds from operations, (iii) normalized earnings attributable to common shareholders, and (iv) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective. Reconciliations of adjusted EBITDA to net income (loss), funds from operations to net cash flows from operating activities and normalized earnings attributable to common shareholders to net income (loss) attributable to shareholders of the Company are contained in the Company's Management's Discussion and Analysis, prepared as of July 22, 2016, for the six months ended June 30, 2016 which is available under the Company's profile on SEDAR at www.SEDAR.com.

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 expectations regarding: (i) compensation to be received by the Company from the Government of Alberta in respect of the proposed early retirement of coal facilities (ii) the structure and stability of Alberta's merchant power market and (iii) growth opportunities that may come to the Company as a result of new renewable electricity generation capacity.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity and other energy prices, (ii) performance, (iii) business prospects and opportunities including expected growth and capital projects, (iv) status and impact of policy, legislation and regulation, 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 prices in markets in which the Company operates, (ii) changes in energy commodity market prices and use of derivatives, (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) power plant availability and performance including maintenance of equipment, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's Management's Discussion and Analysis, prepared as of July 22, 2016, for further discussion of these and other risks.

For more information, please contact:

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of July 22, 2016, 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, 2016, the audited consolidated financial statements and MD&A of Capital Power Corporation for the year ended December 31, 2015, the annual information form of Capital Power Corporation dated March 2, 2016, and the cautionary statements regarding forward-looking information that begin on page 7. 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, 2016 and the six months ended June 30, 2015 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods that 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 22, 2016.

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FORWARD-LOOKING INFORMATION

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

- future revenues, expenses, earnings and funds from operations,
- the future pricing of electricity and market fundamentals in existing and target markets,
- future dividend growth,
- the Company's future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions,
- the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings,
- future growth and emerging opportunities in the Company's target markets including the focus on certain technologies,
- the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions,
- plant availability and planned outages,
- capital expenditures for plant maintenance and other (sustaining capital, future growth projects),
- the impact of environmental regulations on the Company, its businesses, accounting policies, and emissions compliance costs,
- the impact of the Alberta Climate Leadership Plan (CLP) on the Company's future growth projects including the Genesee 4 and 5 project, and
- compensation to be received by the Company from the Government of Alberta in respect of the proposed early retirement of coal facilities.

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

- electricity and other energy prices,
- performance,
- business prospects and opportunities, including expected growth and capital projects,
- status of and impact of policy, legislation and regulations,
- effective tax rates, and
- other matters discussed under the Performance Overview and Outlook sections.

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

- changes in electricity prices in markets in which the Company operates,
- changes in energy commodity market prices and use of derivatives,
- regulatory and political environments including changes to environmental, financial reporting and tax legislation,
- power plant availability and performance including maintenance of equipment,
- ability to fund current and future capital and working capital needs,
- acquisitions and developments including timing and costs of regulatory approvals and construction,
- changes in market prices and availability of fuel, and
- changes in general economic and competitive conditions.

See Risks and Risk Management in the Company's December 31, 2015 annual MD&A for further discussion of these and other risks.

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

OVERVIEW OF BUSINESS AND CORPORATE STRUCTURE

Capital Power is a growth-oriented North American power producer headquartered in Edmonton, Alberta. The Company develops, acquires, operates and optimizes power generation from a variety of energy sources. Capital Power owns more than 3,200 megawatts (MW) of power generation capacity across North America and owned 371 MW of capacity through its interest in the acquired Sundance C power purchase arrangement (Sundance PPA) until the Company notified the Balancing Pool of the Company's decision to terminate its role as Buyer of the Sundance PPA, effective March 24, 2016 (See Significant Events). More than 700 MW of owned generation capacity is in advanced development in Alberta and Kansas.

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP), a wholly owned subsidiary of the Company.

CORPORATE STRATEGY

The Company's corporate strategy remains unchanged from that disclosed in its 2015 annual MD&A.

PERFORMANCE OVERVIEW

The Company measures its performance in relation to its corporate strategy through financial and non-financial targets that are approved by the Board of Directors. The measurement categories include corporate measures and measures specific to certain groups within the Company. The corporate measures are company-wide and include funds from operations, safety and compensation for the proposed accelerated closure of the Company's coal facilities. The group-specific measures include plant operating margin and other operations measures, committed capital, construction and maintenance capital on budget and on schedule, and plant site safety.

Alberta Climate Leadership Plan

	2016 target	Actual results for the six months ended June 30, 2016
Compensation	Ensure fair compensation will be received for the proposed accelerated closure of the Company's coal facilities.	The Alberta government appointed the coal phase-out facilitator (Facilitator) and outlined his scope of work. A report from the Facilitator is expected in the latter half of 2016 (see Significant Events).

The Facilitator will engage with those coal-fired electricity generators operating units beyond 2030 to develop options for the Alberta government to phase out coal-fired electricity emissions by 2030 that will maintain the reliability of Alberta's electricity grid and price stability for consumers, while preventing unnecessarily stranding capital assets. The Company continues to be engaged with the Alberta government on this topic and will work with the Facilitator throughout the process to ensure fair compensation will be received.

Operational excellence

Performance measure	2016 target	Actual results for the six months ended June 30, 2016
Plant availability average [1]	94% or greater	93%
Capital expenditures for plant maintenance, Genesee mine and other (sustaining capital expenditures)	$65 million	$33 million
Plant operating and maintenance expenses	$200 million to $220 million	$108 million

[1] All plants excluding Sundance PPA.

The Company's plant availability averaged 93% which reflected planned outages at Genesee 2, Clover Bar Energy Centre, Shepard, Southport, Roxboro and Joffre. Unplanned outages also occurred at Keephills 3, Southport, Genesee and Joffre which were offset by the planned Genesee 2 shutdown being completed earlier than budgeted.

Sustaining capital expenditures for the six months ended June 30, 2016 were lower than target for the year to date but the full year expenditures are expected to be consistent with the target range.

The plant operating and maintenance expenses target includes other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expenses for the Company's plants. The actual results for the six months ended June 30, 2016 were consistent with the target range.

Disciplined growth

Performance measure	2016 target	Status as at June 30, 2016
Genesee 4 and 5	Proceed with construction based on clarification regarding the CLP and price signals from the energy only market.	Awaiting clarification regarding the CLP and the assessment of potential impacts on current Alberta assets.
New development	Execute a contract for the output of a new development.	Construction of the Bloom Wind project (Bloom Wind) is expected to commence in the third quarter of 2016, and Capital Power will operate the facility under a 10-year fixed price contract (see Significant Events).

See Outlook section below for further discussion of updated timing of completion of the Genesee 4 and 5 project.

Financial stability and strength

Performance measure	2016 target	Actual results for the six months ended June 30, 2016
Funds from operations [1]	$380 million to $430 million	$215 million

[1] Funds from operations is a non-GAAP measure. See Non-GAAP Financial Measures.

Actual funds from operations for the six months ended June 30, 2016 were in line with expected funds from operations for the full year.

OUTLOOK

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

At its Investor Day held in December 2015, the Company provided financial guidance for 2016 funds from operations in the range of $380 million to $430 million. This was based on baseload generation from the Company's Alberta commercial portfolio, hedged at 100%, with average contracted prices of high-$40 per MWh. Since then, the termination of the Sundance PPA (see Significant Events) increased the hedged portion of Capital Power's Alberta commercial portfolio and reduced the Company's contractual obligations in 2016. Based on actual results for the second quarter of 2016 and the Company's forecast for the two future quarters, it is still expected that funds from operations for the full year will be in the target range.

In 2016, the Company will continue to work with the Alberta government and the appointed Facilitator to ensure that fair compensation is received for the proposed accelerated closure of its coal facilities in connection with the CLP. The Company will also continue to work diligently with regulators and other generators in the province to implement the Carbon Competiveness Regulation (CCR) and to develop a planned transition away from coal-fired generation that does not compromise the electricity market design in Alberta. Further investment in the Alberta market, including continuation of construction of the Genesee 4 and 5 project, will be considered once sufficient detail about the CLP is released and the Company has assessed the impact on its existing Alberta assets.

In conjunction with Capital Power's partner, ENMAX Corporation, on the Genesee 4 and 5 project, the construction execution of the project has been restructured by the Company at modestly higher costs and risk, to move the decision point to the fourth quarter of 2016. Accordingly, assuming that favourable conditions exist by the end of 2016, the Company expects to proceed with the project targeting substantial completion of the first unit in early 2020.

In 2016, Capital Power's availability target of 94% reflects major scheduled maintenance outages for Genesee 2, Genesee 3, Joffre, and Shepard compared with the 2015 major scheduled maintenance outages for Genesee 1 and Keephills 3. With all of its baseload power position hedged in 2016, the Company will continue to focus on operational excellence at its operated facilities and to work with its partners in other facilities to ensure that the past excellent availability continues throughout 2016.

Portfolio position, contracted prices and forward Alberta pool prices for 2017, 2018 and 2019, as at June 30, 2016, were:

Alberta commercial portfolio positions and power prices	Full year 2017	Full year 2018	Full year 2019
Percentage of baseload generation sold forward [1]	100%	54%	44%
Contracted price [2]	Mid-$40 per MWh	Low-$50 per MWh	Low-$50 per MWh
Forward Alberta pool prices	$37.50	$46.50	$51.75

[1] Based on the Alberta baseload plants plus a portion of Joffre and the uncontracted portion of Shepard baseload. The Sundance PPA is no longer a part of Capital Power's baseload generation effective March 24, 2016 (see Significant Events).

[2] Forecasted average contracted prices may differ significantly from the future average realized prices as the hedged and unhedged positions have a mix of varyingly priced blocks of power.

The 2016 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. They do not, however, include the effects of potential future acquisitions, development activities, or potential market and operational impacts relating to unplanned plant outages, including outages at facilities of other market participants, and the related impacts on market power prices.

At its Investor Day held in December 2015, the Company provided 7% annual dividend growth guidance from 2016 through 2018. Each annual increase is subject to approval by the Board of Directors of Capital Power at the time of the increase. See Subsequent Event for annual dividend increase effective for the third quarter of 2016.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding.

NON-GAAP FINANCIAL MEASURES

The Company uses (i) earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense from joint venture, and gains or losses on disposals (adjusted EBITDA), (ii) funds from operations, (iii) normalized earnings attributable to common shareholders, and (iv) normalized earnings per share as financial performance measures.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and are therefore 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 plants and categories of plants from period to period. Management believes that a measure of plant operating performance is more meaningful if results not related to plant operations such as impairments, foreign exchange gains or losses, and gains or losses on disposals are excluded from the adjusted EBITDA measure.

Commencing with the Company's March 31, 2016 quarter-end, the reported adjusted EBITDA measure was changed to include Capital Power's share of adjusted EBITDA from joint venture. All comparative adjusted EBITDA amounts for quarters prior to those ended on March 31, 2016 were revised to conform with this change.

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

(unaudited, $ millions)	Three months ended							
	Jun 30 2016	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**
Revenues	229	341	341	469	83	358	432	248
Adjusted EBITDA from joint venture [1]	9	11	13	6	2	-	-	-
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expenses	(130)	(232)	(220)	(321)	(38)	(211)	(291)	(157)
Adjusted EBITDA	**108**	**120**	**134**	**154**	**47**	**147**	**141**	**91**
Depreciation and amortization	(54)	(56)	(56)	(53)	(55)	(51)	(49)	(47)
Foreign exchange (loss) gain	(1)	8	-	(8)	1	(8)	(4)	(5)
Loss on termination of power purchase arrangement	-	(53)	-	-	-	-	-	-
Finance expense	(19)	(22)	(27)	(25)	(24)	(18)	(16)	(15)
Finance expense from joint venture [1]	(4)	(3)	(3)	(2)	(1)	-	-	-
Income tax expense	(10)	(2)	(14)	(16)	(16)	(20)	(24)	(81)
Net income (loss)	**20**	**(8)**	**34**	**50**	**(48)**	**50**	**48**	**(57)**
Net (loss) income attributable to:								
Non-controlling interests	(3)	(2)	(1)	1	(14)	10	9	(12)
Shareholders of the Company	23	(6)	35	49	(34)	40	39	(45)
Net income (loss)	**20**	**(8)**	**34**	**50**	**(48)**	**50**	**48**	**(57)**

[1] Total income from joint venture as per the Company's Condensed Interim Consolidated Statements of Income (Loss).

Funds from operations

Capital Power uses funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund capital expenditures, debt repayments, dividends to the Company's shareholders, and distributions to non-controlling interests. Funds from operations are net cash flows from operating activities adjusted to include finance and current income tax expenses and exclude changes in operating working capital. They also include 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. The Company includes interest and current income tax expenses excluding Part VI.1 tax recorded during the period rather than interest and income taxes paid. The timing of cash receipts and payments of interest and income taxes and the resulting cash basis amounts are not comparable from period to period. The timing of cash receipts and payments also affects the period-to-period comparability of changes in operating working capital which are also excluded from funds from operations.

Commencing with the Company's December 31, 2014 quarter-end, the reported funds from operations measure was changed to remove 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. The impact of the fair value changes in derivatives reflected as cash settlement was immaterial for quarters prior to the fourth quarter of 2014.

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

(unaudited, $ millions)	**Three months ended June 30**		**Six months ended June 30**	
	2016	**2015**	**2016**	**2015**
Net cash flows from operating activities per Consolidated Statements of Cash Flows	**70**	**14**	**201**	**121**
Add (deduct) items included in calculation of net cash flows from operating activities per Consolidated Statements of Cash Flows:				
Interest paid	23	26	41	34
Change in fair value of derivatives reflected as cash settlement	13	22	13	22
Realized gains on the settlement of interest rate derivatives	-	(1)	-	(1)
Miscellaneous financing charges paid [1]	-	2	1	3
Income taxes paid	1	1	1	1
Change in non-cash operating working capital	16	28	(3)	34
	53	78	53	93
Finance expense [2]	(17)	(22)	(39)	(36)
Current income tax expense	(2)	(3)	(7)	(5)
Decrease in current income tax expense due to Part VI.1 tax	2	3	7	5
Funds from operations	**106**	**70**	**215**	**178**

1 Included in other items of non-cash adjustments to reconcile net income (loss) to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts and amortization, accretion charges and non-cash finance charges incurred on early debt extinguishment.

Normalized earnings attributable to common shareholders and normalized earnings per share

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

(unaudited, $ millions except per share amounts and number of common shares)	Three months ended							
	Jun 30 2016	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**
Basic earnings (loss) per share ($)	**0.19**	**(0.11)**	**0.29**	**0.44**	**(0.39)**	**0.41**	**0.40**	**(0.62)**
Net income (loss) attributable to shareholders of the Company per Condensed Interim Consolidated Statements of Income (Loss)	**23**	**(6)**	**35**	**49**	**(34)**	**40**	**39**	**(45)**
Preferred share dividends including Part VI.1 tax	(5)	(5)	(6)	(5)	(6)	(6)	(6)	(6)
Earnings (loss) attributable to common shareholders	18	(11)	29	44	(40)	34	33	(51)
Unrealized foreign exchange loss (gain) on revaluation of U.S. dollar denominated debt	1	(8)	1	6	(2)	10	4	5
Unrealized changes in fair value of derivatives	10	5	11	(19)	33	(17)	(21)	(3)
Loss on termination of the Sundance PPA	-	46	-	-	-	-	-	-
Income tax expense related to increase in deferred tax liabilities caused by change in Alberta statutory corporate income tax rate	-	-	-	-	19	-	-	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	-	-	-	-	(1)	-	1	-
Write-down of U.S. deferred tax assets	-	-	-	-	-	-	-	59
Restructuring charges	-	-	-	2	-	-	-	-
Recognition of tax liability on foreign domiciled investment	-	-	-	-	1	-	-	-
Normalized earnings attributable to common shareholders	**29**	**32**	**41**	**33**	**10**	**27**	**17**	**10**
Weighted average number of common shares outstanding (millions)	96.1	96.4	98.7	100.9	102.1	83.7	83.3	82.8
Normalized earnings per share ($)	**0.30**	**0.33**	**0.42**	**0.33**	**0.10**	**0.32**	**0.20**	**0.12**

Normalized earnings per share reflects the period-over-period change in normalized earnings attributable to common shareholders and the changes from period to period as the weighted average number of common shares outstanding increases or decreases and the net income attributable to non-controlling interests decreases.

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Revenues	229	83	570	441
Adjusted EBITDA [1]	108	47	228	194
Net income (loss)	20	(48)	12	2
Net income (loss) attributable to shareholders of the Company	23	(34)	17	6
Normalized earnings attributable to common shareholders [1]	29	10	61	37
Basic and diluted earnings (loss) per share ($) [2]	0.19	(0.39)	0.07	(0.06)
Normalized earnings per share ($) [1]	0.30	0.10	0.63	0.40
Funds from operations [1]	106	70	215	178
Purchase of property, plant and equipment and other assets	81	35	112	87
Dividends per common share, declared ($)	0.3650	0.3400	0.7300	0.6800
Dividends per Series 1 preferred share, declared ($)	0.1913	0.2875	0.3826	0.5750
Dividends per Series 3 preferred share, declared ($)	0.2875	0.2875	0.5750	0.5750
Dividends per Series 5 preferred share, declared ($)	0.2813	0.2813	0.5626	0.5626

	As at	
	June 30, 2016	December 31, 2015
Loans and borrowings including current portion	1,552	1,615
Total assets	5,215	5,393

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

2 Diluted earnings (loss) per share was calculated after giving effect to outstanding share purchase options and the subsequent exchange of common limited partnership units of CPLP held by EPCOR Utilities Inc. (EPCOR) which were exchangeable for common shares of Capital Power on a one-for-one basis as at March 31, 2015. All common limited partnership units of CPLP were subsequently exchanged on April 2, 2015.

Normalized earnings attributable to common shareholders and normalized earnings per share

Normalized earnings attributable to common shareholders and normalized earnings per share for the second quarter of 2016 were higher compared with the second quarter of 2015. See Consolidated Net Income (Loss) and Results of Operations for key drivers of the increases for the quarter. The number of common shares outstanding increased as a result of the common shares issued to EPCOR following the secondary offering and exchange of exchangeable common limited partnership units on April 2, 2015.

Funds from operations

Funds from operations for the three months ended June 30, 2016 were higher compared with funds from operations for the three months ended June 30, 2015 primarily due to higher adjusted EBITDA before unrealized changes in fair value of commodity derivatives and emission credits and Capital Power's share of the adjusted EBITDA from K2 Wind; lower finance expense, and higher cash distributions received from K2 Wind also contributed to higher funds from operations. For the six months ended June 30, 2016, the above impacts were partly offset by higher finance expense in 2016 as a result of lower capitalized interest given the completion of Shepard in March 2015.

SIGNIFICANT EVENTS

Completion of contract for output for Bloom Wind

On April 25, 2016, Capital Power announced that construction of its Bloom Wind project (Bloom Wind) is expected to commence in the third quarter of 2016. Bloom Wind is a 178 MW facility in southwestern Kansas consisting of 54 3.3 MW turbines and is anticipated to cost $358 million (US$272 million). Commercial operation of the facility is expected in the third quarter of 2017. Capital Power will operate Bloom Wind under a 10-year fixed price contract with Allianz Risk Transfer (rated AA- stable by Standard & Poor's), a subsidiary of Allianz SE, the worldwide insurance and asset management group, covering 100% of the project's output. Under the contract, which was executed on April 21, 2016, Capital Power will swap the market revenue of the project's generation for a fixed annual payment for a 10-year term. The agreement will secure long-term predictable revenues and mitigate generation volume uncertainty related to wind resources, allowing Bloom Wind to secure renewable energy tax equity financing and provide Capital Power the opportunity to complete its first wind development project in the growing U.S. renewables market.

Approval of normal course issuer bid

On April 25, 2016, Capital Power announced that the Toronto Stock Exchange (TSX) approved the Company's normal course issuer bid (NCIB) to purchase and cancel up to 8.6 million of its outstanding common shares during the one year period from April 28, 2016 to April 27, 2017. Capital Power purchased and cancelled 7.1 million common shares under its prior NCIB approved by the TSX on March 25, 2015 for the period from April 7, 2015 to April 6, 2016, but has not yet purchased and cancelled any common shares under the NCIB approved on April 25, 2016.

Termination of the Sundance PPA

On March 24, 2016, Capital Power notified the Balancing Pool of the Company's decision to terminate its role as Buyer of the Sundance PPA effective March 24, 2016. Capital Power exercised its right to terminate the Sundance PPA under the Change in Law provisions of the arrangement, following changes to the Specified Gas Emitters Regulation (SGER) that took effect at the start of 2016. As a result of this termination, no further economic benefits are expected from the Sundance PPA and the related intangible asset was derecognized. The Company has recorded a non-cash pre-tax loss of $53 million ($46 million post-tax) with respect to the derecognition of the Sundance PPA asset. The Balancing Pool and Capital Power could differ in opinion as to the effective termination date. See Contractual Obligations and Contingent Liabilities for further discussion.

CLP Update

On March 16, 2016, the Alberta government appointed a Facilitator to oversee the transition away from coal-fired generation in Alberta by 2030. The Facilitator's background is with large public power providers and centrally dispatched power systems and advising energy leaders in numerous countries around the world. The Facilitator's mandate is to provide options and preferred approaches to the Alberta government to phase out emissions from coal-fired generation by 2030 that will maintain the reliability of Alberta's electricity grid and price stability for consumers while preventing unnecessarily stranding capital assets. Throughout this process, the Alberta government has indicated that it intends to ensure that affected workers, communities and companies are treated fairly. It is expected that the Facilitator will report to the Alberta government on this mandate in the latter half of 2016. Capital Power is participating in the Facilitator process to ensure that fair compensation is received for the proposed accelerated closure of the Company's coal facilities.

On January 26, 2016, the Alberta government tasked the Alberta Electric System Operator (AESO) to develop and implement a plan to bring on new renewable electricity generation capacity to the grid by 2030 in connection with the CLP. The Alberta government mandated that the process must be carefully managed and operate in concert with the retirement of the current coal generating units. The Alberta government also confirmed that it has not chosen to fundamentally alter the current wholesale electricity market structure. The AESO undertook a process to receive industry perspectives regarding various elements of the Renewable Energy Program (REP), and provided its recommendations regarding the REP to the Alberta government on May 31, 2016. The recommendations have not been made public. It is currently expected that the Alberta government will provide direction on the REP by the third quarter of 2016, and the AESO currently expects to initiate the process for the first procurement by year-end.

As of July 22, 2016, the Alberta government has yet to initiate formal consultations relating to the Carbon Competitiveness Regulation (CCR Regulation). The CCR Regulation will establish the performance standard and carbon pricing framework that will apply to facilities that are currently subject to the Specified Gas Emitters Regulation (SGER), and will replace SGER effective January 1, 2018. The CLP provided general direction that the performance standard for the electricity sector will be based on the emissions performance of the cleanest natural gas-fired facility in Alberta, with specific details to be developed through consultation.

Capital Power looks forward to further clarifications of the renewable electricity program and the growth opportunities that this may bring to the Company.

Preferred Shares (Series 1) dividend rate reset

On February 18, 2016 the Board of Directors of Capital Power declared a quarterly dividend of $0.19125 per share on the Company's Cumulative 5-Year Rate Reset Preference Shares, Series 1 (Series 1 Shares). This quarterly dividend was paid on March 31, 2016. The Annual Fixed Dividend Rate for the Series 1 Shares for the next five year period was reset from 4.60% to 3.06% on December 31, 2015 at a rate equal to the sum of the then Government of Canada bond yield and 2.17%. The Annual Fixed Dividend Rate will be next reset on December 31, 2020 and every five years thereafter.

SUBSEQUENT EVENT

Dividend Increase

On July 25, 2016, the Company announced that its Board of Directors approved a 6.8% increase in the annual dividend for holders of its common shares, from $1.46 per common share to $1.56 per common share. This increased common dividend will commence with the third quarter 2016 quarterly dividend payment payable on October 31, 2016 to shareholders of record at the close of business on September 30, 2016.

CONSOLIDATED NET INCOME (LOSS) AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income (loss) for the three and six months ended June 30, 2016 compared with the three and six months ended June 30, 2015 are presented below followed by further discussion of these items.

(unaudited, $ millions)	Three months		Six months	
Consolidated net (loss) income for the periods ended June 30, 2015		**(48)**		**2**
Increase (decrease) in adjusted EBITDA:				
Alberta commercial plants and portfolio optimization	22		23	
Alberta contracted plants	(2)		(2)	
Ontario and British Columbia contracted plants	7		15	
U.S. contracted plants	2		5	
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits	32	61	(7)	34
Increase (decrease) in depreciation and amortization expense		1		(4)
Change in foreign exchange gain or loss		(2)		14
Loss on termination of power purchase arrangement		-		(53)
Decrease in finance expense		5		1
Increase in finance expense from joint venture		(3)		(6)
Increase (decrease) in income before tax		62		(14)
Decrease in income tax expense		6		24
Increase in net income		**68**		**10**
Consolidated net income for the periods ended June 30, 2016		**20**		**12**

Results by Plant Category and Other

	Three months ended June 30							
	2016	2015	2016	2015	2016	2015	2016	2015
	Electricity generation (GWh) [1]		Plant availability (%) [2]		Revenues (unaudited, $ millions)		Adjusted EBITDA (unaudited, $ millions) [3]	
Total electricity generation, average plant availability and plant revenues excluding Sundance PPA	3,707	3,553	90	90	173	228		
Alberta commercial plants and Sundance PPA								
Genesee 3	474	491	100	100	6	27		
Keephills 3	501	436	100	97	7	22		
Clover Bar Energy Centre 1, 2 and 3	106	98	91	95	2	16		
Joffre	21	76	55	87	6	11		
Shepard Energy Centre [4]	647	443	82	73	23	23		
Halkirk	124	107	98	98	8	9		
Clover Bar Landfill Gas	2	3	99	93	-	-		
Alberta commercial plants – owned	1,875	1,654	87	89	52	108		
Sundance PPA [5]	-	565	-	79	-	27		
Portfolio optimization	N/A	N/A	N/A	N/A	114	(5)		
	1,875	2,219	87	86	166	130	71	49
Alberta contracted plants								
Genesee 1	770	608	95	72				
Genesee 2	582	838	72	100				
	1,352	1,446	84	86	62	67	43	45
Ontario and British Columbia contracted plants								
Island Generation	-	37	100	100	9	9		
K2 Wind [6]	34	19	99	98	-	N/A		
Kingsbridge 1	16	21	97	95	1	1		
Port Dover and Nanticoke	65	69	100	97	8	9		
Quality Wind	90	82	98	97	7	6		
	205	228	99	98	25	25	28	21
U.S. contracted plants								
Roxboro, North Carolina	82	70	100	87	9	8		
Southport, North Carolina	144	118	92	88	19	16		
Beaufort Solar, North Carolina [7]	8	N/A	91	N/A	1	N/A		
Macho Springs, New Mexico	41	37	98	99	5	4		
	275	225	95	91	34	28	8	6
Corporate [8]					1	4	(27)	(27)
Unrealized changes in fair value of commodity derivatives and emission credits					(59)	(171)	(15)	(47)
Consolidated revenues and adjusted EBITDA					**229**	**83**	**108**	**47**

	Six months ended June 30							
	2016	2015	2016	2015	2016	2015	2016	2015
	Electricity generation (GWh) [1]		**Plant availability** (%) [2]		**Revenues** (unaudited, $ millions)		**Adjusted EBITDA** (unaudited, $ millions) [3]	
Total electricity generation, average plant availability and plant revenues excluding Sundance PPA	7,605	6,951	93	94	361	406		
Alberta commercial plants and Sundance PPA								
Genesee 3	948	984	100	100	14	41		
Keephills 3	889	893	95	99	14	35		
Clover Bar Energy Centre 1, 2 and 3	154	168	95	96	3	21		
Joffre	104	162	72	94	12	18		
Shepard Energy Centre [4]	1,224	503	91	74	44	24		
Halkirk	248	243	98	98	16	18		
Clover Bar Landfill Gas	3	5	99	96	-	-		
Alberta commercial plants – owned	3,570	2,958	92	93	103	157		
Sundance PPA [5]	655	1,256	95	85	13	47		
Portfolio optimization	N/A	N/A	N/A	N/A	238	142		
	4,225	4,214	93	90	354	346	135	112
Alberta contracted plants								
Genesee 1	1,613	1,423	98	85				
Genesee 2	1,415	1,674	85	100				
	3,028	3,097	91	92	133	133	85	87
Ontario and British Columbia contracted plants								
Island Generation	-	37	100	100	19	19		
K2 Wind [6]	105	19	99	98	-	N/A		
Kingsbridge 1	50	52	96	96	3	3		
Port Dover and Nanticoke	160	160	99	98	20	20		
Quality Wind	181	190	99	98	17	19		
	496	458	99	99	59	61	66	51
U.S. contracted plants								
Roxboro, North Carolina	148	129	95	92	17	14		
Southport, North Carolina	271	247	88	88	38	34		
Beaufort Solar, North Carolina [7]	15	N/A	95	N/A	2	N/A		
Macho Springs, New Mexico	77	62	97	99	9	7		
	511	438	92	92	66	55	16	11
Corporate [8]					3	5	(51)	(51)
Unrealized changes in fair value of commodity derivatives and emission credits					(45)	(159)	(23)	(16)
Consolidated revenues and adjusted EBITDA					**570**	**441**	**228**	**194**

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

2 Plant availability represents the percentage of time in the period that the plant 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 plant category, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

4 Shepard was commissioned on March 11, 2015.

5 The Company notified the Balancing Pool of the Company's decision to terminate its role as Buyer of the Sundance PPA effective March 24, 2016 (see Significant Events). Revenues, adjusted EBITDA, electricity generation, and plant availability in 2016 include the results of the Sundance PPA up to the effective termination date.

6 K2 Wind is accounted for under the equity method. Capital Power's share of the plant's net income is included in income from joint venture on the Company's Condensed Interim Consolidated Statements of Income (Loss). The plant was commissioned on May 29, 2015 and the equivalent of Capital Power's share of the plant's revenues was $10 million and $23 million for the

three and six months ended June 30, 2016, respectively, compared with $2 million for the three and six months ended June 30, 2015, which are not included in the above results.

7 Beaufort Solar was commissioned on December 22, 2015.

8 Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

		Three months ended June 30		Six months ended June 30		Year ended December 31, 2015
Alberta	**Unit**	**2016**	**2015**	**2016**	**2015**	
Hedged position [1]	Percentage sold forward at beginning of period (%)	100	100	100	100	97
Spot power price average	$/MWh	15	57	17	43	33
Realized power price [2]	$/MWh	61	46	56	53	55
Natural gas price (AECO) [3]	$/gigajoule (Gj)	1.34	2.52	1.54	2.58	2.60

1 Hedged position is for the Alberta baseload plants and a portion of Joffre and the uncontracted portion of Shepard baseload. The Sundance PPA is no longer a part of Capital Power's baseload generation effective March 24, 2016 (see Significant Events).

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

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

Alberta commercial plants, Sundance PPA and portfolio optimization

The Alberta spot power price averaged $15 per MWh and $17 per MWh for the three and six months ended June 30, 2016, respectively which were lower than the corresponding periods in 2015. Alberta spot power prices in 2016 were primarily driven by low natural gas prices, strong wind supply and conservative offer strategies from market participants.

Generation, availability, revenues, and adjusted EBITDA for the Alberta commercial plants include results of the Sundance PPA up to the effective termination date of March 24, 2016 (see Significant Events).

For the three months ended June 30, 2016, generation was lower than the comparable period in 2015 primarily due to the termination of the Sundance PPA in the first quarter of 2016. This was partially offset by higher generation at Shepard in 2016, as the facility experienced an unplanned outage during the second quarter of 2015. Availability for the second quarter ended June 30, 2016 was not materially different from the same quarter in 2015 due to fewer outage hours at Shepard offset by planned outages at CBEC as well as planned and unplanned outages at Joffre.

For the six months ended June 30, 2016, generation increased compared with the same periods in 2015 primarily due to stronger performance at Shepard given no comparable outage at the facility in 2016 combined with the commissioning of Shepard in March 2015. Partially offsetting this was the termination of the Sundance PPA. Availability for these comparative periods also increased primarily due to significantly higher Shepard availability partially offset by second quarter outages, as discussed above, as well as a first quarter forced outage at Keephills 3.

Revenues for the Alberta commercial plants were lower for the three and six months ended June 30, 2016 compared with the same periods in 2015 mainly as a result of lower average Alberta spot prices. Portfolio optimization revenues were higher in the current period compared with 2015, as the portfolio was fully hedged at an average realized price of $61 per MWh and $56 per MWh for the three and six months ended June 30, 2016, respectively compared to $46 per MWh and $53 per MWh for the same periods in 2015. Second quarter revenues in 2015 were also negatively impacted as the Company was required to cover a short market position at higher prices. The above factors also contributed to the increase in adjusted EBITDA in 2016 as compared with the same periods in 2015.

Adjusted EBITDA for the three and six months ended June 30, 2016 was higher than the same periods in 2015 resulting from strong portfolio optimization performance offset by unfavorable commercial plant results.

Alberta contracted plants

For the three and six months ended June 30, 2016 compared with the same periods in 2015, generation and availability decreased as a result of higher planned and unplanned outage hours experienced at Genesee 2, partially offset by the early completion of the planned Genesee 2 turnaround during the second quarter of 2016, which incurred fewer outage hours compared with the Genesee 1 turnaround in 2015. Lower revenues and adjusted EBITDA in the second quarter of 2016 were primarily attributed to lower excess energy and incentive revenues received. On a year to date basis, the aforementioned impacts to revenues in 2016 were partially offset by the recovery of environmental compliance costs received from the Balancing Pool. As a result of changes to the SGER effective January 1, 2016, the Company incurred higher compliance costs. However, under the terms of the PPA with the Balancing Pool, increases in environmental compliance costs for the Alberta plants are passed onto the Balancing Pool until the PPA expires at the end of 2020.

Ontario and British Columbia contracted plants

Generation and adjusted EBITDA increased in the three and six months ended June 30, 2016 compared with the corresponding periods in 2015 due to the addition of K2 Wind, which began commercial operations on May 29, 2015. The increase in generation for the three months ended June 30, 2016 over the three months ended June 30, 2015, driven by K2 wind was more than offset by lower generation as a result of Island Generation not being dispatched during 2016. Revenues for 2016 do not include the revenues of K2 Wind which is accounted for under the equity method.

U.S. contracted plants

For the three and six months ended June 30, 2016, generation, revenues and adjusted EBITDA increased when compared with the same periods in 2015 due to higher off-peak generation at Southport and Roxboro, the addition of Beaufort Solar in the fourth quarter of 2015 and increased wind generation at Macho Springs.

Availability for the three months ended June 30, 2016 compared to the corresponding period in 2015 increased due to an absence of outages at Roxboro during the quarter, slightly offset by lower availability at Macho Springs. Availability for the six months ended June 30, 2016 was consistent with performance in the comparable periods in 2015.

Corporate

Corporate includes (i) revenues for cost recoveries, (ii) the cost of support services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management, and environment, health and safety, and (iii) business development expenses. The cost recovery revenues are primarily intercompany revenues which are offset by interplant category transactions.

The Corporate category's net expenditures for the periods ended June 30, 2016 were consistent compared with the periods ended June 30, 2015.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	**Three months ended June 30**			
Unrealized changes in fair value of commodity derivatives and emission credits	**2016**	**2015**	**2016**	**2015**
	Revenues		**Adjusted EBITDA**	
Unrealized losses on Alberta energy derivatives	(52)	(159)	(29)	(46)
Unrealized (losses) gains on natural gas derivatives	(6)	(11)	15	-
Unrealized losses on emission derivatives	(1)	(1)	(1)	-
Unrealized losses on emission credits held for trading	-	-	-	(1)
	(59)	**(171)**	**(15)**	**(47)**

(unaudited, $ millions)	**Six months ended June 30**			
Unrealized changes in fair value of commodity derivatives and emission credits	**2016**	**2015**	**2016**	**2015**
	Revenues		**Adjusted EBITDA**	
Unrealized losses on Alberta energy derivatives	(39)	(120)	(28)	(24)
Unrealized (losses) gains on natural gas derivatives	(1)	(40)	13	8
Unrealized (losses) gains on emission derivatives	(5)	1	(5)	1
Unrealized losses on emission credits held for trading	-	-	(3)	(1)
	(45)	**(159)**	**(23)**	**(16)**

The Company's financial results relating to its Alberta commercial plants and portfolio optimization include unrealized changes in the fair value of commodity and other derivatives.

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

During the three months ended, June 30, 2016 and 2015, the Alberta energy portfolio recognized unrealized losses of $29 million and $46 million respectively due to the impact of increasing forward power prices combined with the portfolio's net forward sales contracts. During the six months ended June 30, 2016 and 2015, the Company recognized unrealized losses of $28 million and $24 million respectively. This reflected the reversal of prior periods' unrealized net gains on forward sales contracts that settled during the first six months in the corresponding years. There were additional unrealized losses in 2016 that were the result of decreasing forward prices on existing portfolio positions.

Unrealized gains on natural gas derivatives reported by the Company in 2016 and 2015 were attributable to reversals of previously unrealized net losses on contracts which settled in the corresponding periods. In 2016, the unrealized gains were further attributed to net forward purchase contracts entered into which were valued against increasing forward natural gas prices as at June 30, 2016.

Unrealized losses on emission derivatives of $5 million for the six months ended June 30, 2016 resulted from net forward purchase contracts on allowances and renewable energy credits which were valued at decreasing prices and reversal of prior period gains on positions settled during the first six months of 2016, partially offset by a gain on net forward sale contracts valued at decreasing prices. Emission portfolio activities for the comparable periods in 2015 were immaterial.

During six months ended June 30, 2016, the Company recognized unrealized net losses in fair value of emission credits held for trading of $3 million primarily due to the reversal of previously unrealized net gains.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $ millions)	**Three months ended June 30**		**Six months ended June 30**	
	2016	**2015**	**2016**	**2015**
Interest on borrowings less capitalized interest	(17)	(21)	(38)	(34)
Realized gains on settlement of interest rate derivatives	-	1	-	1
Other finance expense – sundry interest and guarantee and other fees	-	(2)	(1)	(3)
	(17)	(22)	(39)	(36)
Unrealized loss representing changes in the fair value of interest rate derivatives	(1)	-	-	(2)
Other finance expense – amortization and accretion charges	(1)	(2)	(2)	(3)
Other finance expense – finance charges incurred on early debt extinguishment	-	-	-	(1)
Total finance expense	(19)	(24)	(41)	(42)
Depreciation and amortization	(54)	(55)	(110)	(106)
Foreign exchange (loss) gain	(1)	1	7	(7)
Loss on termination of power purchase arrangement	-	-	(53)	-
Finance expense from joint venture	(4)	(1)	(7)	(1)
Income tax expense	(10)	(16)	(12)	(36)
Net loss attributable to non-controlling interests	3	14	5	4

Finance expense

Finance expense for the three months ended June 30, 2016 decreased compared with the same period in the prior year primarily due to reduced interest expense incurred on long-term debt as a result of EPCOR debt repayment in the first quarter of 2016 and the retirement of medium-term notes in November 2015. Offsetting these impacts on a year to date basis was decreased capitalized interest as Shepard was completed in March 2015 and increased credit facility interest.

Depreciation and amortization

Depreciation and amortization for the six months ended June 30, 2016 increased by $4 million compared with the same period in the prior year primarily due to additional expense recognized for Shepard which commenced commercial operations in March 2015.

Foreign exchange (loss) gain

Foreign exchange consisted of the (loss) gain incurred on the revaluation of U.S. dollar denominated debt not hedged (US$100 million) for accounting purposes. For the six months ended June 30, 2016, the exchange rate of the Canadian dollar relative to the U.S. dollar increased resulting in an unrealized gain of $7 million.

Loss on termination of power purchase arrangement

The Company recorded a pre-tax loss of $53 million with respect to the derecognition of the Sundance PPA intangible asset during the three months ended March 31, 2016. On March 24, 2016, the Company notified the Balancing Pool of the Company's decision to terminate its role as Buyer of the Sundance PPA effective March 24, 2016 (see Significant Events).

Finance expense from joint venture

Finance expense from joint venture includes Capital Power's share of finance expenses of K2 Wind accounted for under the equity method. This plant was commissioned on May 29, 2015.

Income tax expense

For the three and six months ended June 30, 2016 compared with the same periods in the prior year, income tax expense decreased $6 million and $24 million, respectively mainly due to the change in the Alberta statutory income tax rate in the second quarter of 2015 which increased non-cash income tax expense during that period. No comparable non-cash income tax expense was recorded in 2016. For the quarter ended June 30, 2016, this decrease was partly offset by higher taxable income and higher CPLP ownership. For the six months ended June 30, 2016, tax expense decreased due to the above impacts and lower taxable income which was offset by an increase in unrecognized tax benefits.

Non-controlling interests

For the three and six months ended June 30, 2016, none (January 1, 2015 to April 2, 2015, 18%) of CPLP's net income was attributable to EPCOR which was reported as net income attributable to non-controlling interests by the Company in 2015. Effective April 2, 2015, EPCOR disposed of all its interest in CPLP. Subsequent to April 2, 2015, non-controlling interests consist only of the Genesee Coal Mine Assets (Coal Mine) partner's share of the consolidated net income of the Coal Mine.

COMPREHENSIVE LOSS

(unaudited, $ millions)	Three months ended June 30		Six months ended June 30	
	2016	**2015**	**2016**	**2015**
Net income (loss)	20	(48)	12	2
Other comprehensive (loss):				
Net unrealized (losses) gains on commodity derivatives designated as cash flow hedges	(23)	(89)	11	(41)
Net realized (gains) losses on commodity derivatives designated as cash flow hedges reclassified to revenues and/or energy purchases and fuel	(19)	7	(49)	(14)
Unrealized foreign exchange (loss) gain on the translation of foreign operations	(1)	(2)	(13)	14
	(43)	(84)	(51)	(41)
Comprehensive loss	**(23)**	**(132)**	**(39)**	**(39)**

Other comprehensive 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 (loss). Other unrealized fair value changes on derivatives designated as cash flow hedges and foreign currency translation gain or loss are subsequently recognized in net income (loss) when the hedged transactions are completed and the foreign operations are disposed of or otherwise terminated. As a result of the termination of the Sundance PPA (see Significant Events), certain derivatives that were previously designated as accounting hedges were de-designated as the hedged transactions are no longer expected to occur. The de-designation resulted in the reclassification of unrealized gains of $5 million ($4 million post tax) from other comprehensive loss to net income (loss).

FINANCIAL POSITION

The significant changes in the Consolidated Statements of Financial Position from December 31, 2015 to June 30, 2016 were as follows:

(unaudited, $ millions)	June 30, 2016	December 31, 2015	Increase (decrease)	Primary reason for increase (decrease)
Trade and other receivables	164	190	(26)	Primarily lower generation including reduced generation due to the termination of the Sundance PPA (see Significant Events) and lower Alberta pool prices.
Inventories	90	99	(9)	Increased sales of emission credit inventory.
Net derivative financial instruments assets	104	167	(63)	Due to reversal of prior periods' unrealized net gains on forward sales contracts and unrealized losses on Bloom Power swap.
Equity-accounted investment	-	10	(10)	Due to distributions received and unrealized loss recognized partially offset by net income.
Intangible assets	289	341	(52)	Derecognition of assets related to the Sundance PPA (see Significant Events).
Trade and other payables	148	181	(33)	Due to final construction costs related to Shepard being paid in the first quarter of 2016 and the termination of the Sundance PPA (see Significant Events).
Loans and borrowings (including current portion)	1,552	1,615	(63)	Repayment of debt payable to EPCOR partly offset by increased bankers' acceptances outstanding and US dollar bank loans.
Share capital	2,722	2,744	(22)	Common shares purchased by Capital Power.
Deficit	(133)	(70)	(63)	Net income offset by common and preferred share dividends.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Six months ended June 30		
Cash inflows (outflows)	**2016**	**2015**	**Increase (decrease)**
Operating activities	201	121	80
Investing activities	(112)	(56)	(56)
Financing activities	(139)	(89)	(50)

Operating activities

Cash flows from operating activities for the six months ended June 30 increased year over year primarily due to higher adjusted EBITDA results realized by the Company, distributions received from the K2 Wind joint venture and higher contributions from operating working capital, partly offset by higher interest paid as a result of lower capitalized interest due to the completion of Shepard in the first quarter of 2015.

Investing activities

Cash flows used in investing activities for the six months ended June 30 increased on a quarter-over-quarter basis primarily due to the procurement of turbines for Bloom Wind in 2016.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2016 Actual	Six months ended June 30, 2016 Actual [1]	Balance of 2016 Estimated [2, 3]	Actual or Projected Total [3, 4]	Timing
Shepard	847	-	1	848	Commercial operation commenced March 2015.
Genesee 4 and 5 [5, 6]	9	2	27	700	Targeted substantial completion as early as 2020 and 2021, respectively.
Bloom Wind	-	60	115	358	Targeted completion in mid-2017.
Subtotal growth projects		**62**			
Sustaining – plant maintenance excluding Genesee mine		32			
Sustaining – Genesee mine maintenance and lands [7]		1			
Total capital expenditures[1]		**95**			
Emission credits held for compliance		18			
Capitalized interest		(1)			
Purchase of property, plant and equipment and other assets		**112**			

1 Capital expenditures exclude capitalized interest.

2 The Company's 2016 estimated capital expenditures include only expenditures for previously announced growth projects and exclude other potential new development projects.

3 Costs for the Shepard project completed in 2015 include certain costs that are expected to be incurred subsequent to the date of commercial operations such as capital spares to be received.

4 Projected capital expenditures to be incurred over the life of the project are based on management's estimates.

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

6 Continuation of the Genesee 4 and 5 project will be considered once sufficient detail about the CLP is released and the Company has assessed the impact on its existing Alberta assets. The construction execution of the project has been restructured at modestly higher costs and risk, to move the decision point to the fourth quarter of 2016.

7 Capital expenditures for Genesee mine maintenance represent only those capital expenditures funded by the Company for its share of the Genesee mine operation.

Financing activities

The cash flows used in financing activities for the six months ended June 30, 2016 primarily reflected the sum of common share dividends, preferred share dividends, common shares purchased, and the net repayment of loans and borrowings.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at June 30, 2016			As at December 31, 2015		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
CPLP committed credit facility	2020	1,000			1,000		
Letters of credit outstanding			9			15	
Bankers' acceptances outstanding			315			212	
U.S. dollar bank loans outstanding			36			27	
		1,000	360	640	1,000	254	746
CPLP bilateral demand credit facilities	N/A	200			200		
Letters of credit outstanding			114	86		110	90
CPLP demand credit facility	N/A	20	-	20	20	-	20
Capital Power Corporation demand credit facility	N/A	5	-	5	5	-	5
		1,225	**474**	**751**	**1,225**	**364**	**861**

As at June 30, 2016, the committed credit facility utilization increased $110 million compared with the utilization as at December 31, 2015 primarily due to increased bankers' acceptances outstanding and U.S. dollar bank loans outstanding at June 30, 2016. The increase in bankers' acceptances outstanding was incurred to fund the debt payment made to EPCOR in the first quarter of 2016. The committed credit facility includes an accordion feature that permits an increase to the facility size by $300 million in the future, subject to certain conditions including lender approval. The maturity date of CPLP's credit agreements is July 9, 2020.

The available credit facilities provide the Company with adequate funding for ongoing development projects.

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

The Company has a long-term debt credit rating of BBB from DBRS Limited (DBRS) and on March 10, 2016, DBRS changed the trend of the rating from stable to negative. The negative trend indicates the possibility of a downgrade to BBB (low). The BBB rating 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. 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 2016 include:

(unaudited, $millions)	**Six months ended June 30, 2016 Actual**	**Balance of 2016 estimated**	**Total 2016 Expected Cash Requirements**
Repayment of debt payable to EPCOR	139	-	139
Capital expenditures excluding capitalized interest and emission credits held for compliance	94	172	266
Common share dividends [1]	71	72	143
Preferred share dividends	10	10	20

[1] Includes the 6.8% dividend increase approved by the Board of Directors of Capital Power on July 25, 2016.

The current portion of loans and borrowings on the June 30, 2016 Condensed Interim Consolidated Statements of Financial Position included $186 million of senior debt payable to EPCOR that was classified as current since the debt is callable and, therefore, all potentially repayable within one year.

The Company expects to fund the construction of the Genesee 4 and 5 and Bloom Wind projects using existing bank credit facilities and cash flows from operating activities. The Company's other cash requirements identified above are expected to be funded with cash on hand, cash flows from operating activities, and use of existing bank credit facilities.

The Company uses a short-form base shelf prospectus to provide it with the ability, market conditions permitting, to obtain new debt and equity capital from external markets when required. Under the short-form base shelf prospectus, Capital Power may raise up to $3 billion by issuing common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities. This prospectus expires in June 2018.

If the Canadian and U.S. financial markets become unstable, as they did particularly in the period from 2008 to 2010, Capital Power's ability to raise new capital, to meet its financial requirements, and to refinance indebtedness under existing credit facilities and debt agreements may be adversely affected. Capital Power has credit exposure relating to various agreements, particularly with respect to its PPA, trading and supplier counterparties. While Capital Power continues to monitor its exposure to its significant counterparties, there can be no assurance that all counterparties will be able to meet their commitments.

Off-statement of financial position arrangements

The Company has off-statement of financial position arrangements including operating leases and, as at June 30, 2016, $123 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, 2016	**December 31, 2015**
Loans and borrowings	1,552	1,615
Finance lease obligation [1]	20	22
Less cash and cash equivalents	28	80
Net debt	1,544	1,557
Share capital	2,722	2,744
Deficit and other reserves	(110)	4
Non-controlling interests	63	68
Total equity	2,675	2,816
Total capital	**4,219**	**4,373**

[1] Includes the current portion disclosed within trade and other payables.

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES

Sundance PPA Termination

As at July 22, 2016, Capital Power has not received acceptance of the Sundance PPA termination or of the effective termination date from the Balancing Pool. The Balancing Pool and Capital Power could differ in opinion as to the effective date of termination which, in the event that the termination date is determined to be later than the March 24, 2016 termination notification date, may result in an estimated additional loss of up to $26 million as at June 30, 2016 pertaining to the total Sundance PPA. Of this estimated loss, Capital Power's 52 percent share of up to $13 million as at June 30, 2016 would be recognized in the Company's consolidated statements of (loss) income in the event that the termination date is determined to be later than the March 24, 2016 termination notification date. The calculation of the estimated loss is based on several key assumptions, including output generated by the Sundance PPA units during the period, Alberta power prices that settled during the period, emission intensity factors, and other fixed payment terms as specified in the Sundance PPA. Although there can be no assurance that the termination date will be accepted as filed by the Company, the Company does not believe that the resulting outcome will have a material adverse impact on its financial position.

Line Loss Rule Proceeding

Capital Power is participating in the Line Loss Rule (LLR) Proceeding currently underway before the Alberta Utilities Commission (AUC) regarding loss factors that form the basis for certain transmission charges paid by Alberta generators, including Capital Power. The LLR Proceeding intends to address the replacement for the currently non-compliant LLR as well as the possible correction of line loss charges and credits for the years 2006 forward through three modules. In January 2015, the AUC issued its "Module A" decision and concluded that it has the jurisdiction and authority to retroactively adjust line loss rates. The Module A decision was subsequently appealed by multiple parties, including the Company and consideration of those appeals has been deferred until after the completion of "Module C". The AUC approved principles for the new LLR in "Module B" in November 2015 and has directed the AESO to provide a plan for implementing the new LLR. The AESO submitted a plan that will achieve implementation of the new LLR by January 1, 2017. In June 2016, the AUC rejected applications for review and variance of the Module B decision that had been submitted by two parties, ruling that it would be premature to review the decision prior to completing Module C, but noting that the parties could resubmit the Module B review applications upon completion of Module C. In January 2016, the AUC initiated Module C, which will address issues relating to what retrospective adjustments, if any, are to be paid to or received by the various parties. As of July 22, 2016, the timelines for consideration of Module C issues had not been established by the AUC.

As at July 22, 2016, no prospective (Module B) loss factors or retroactive (Module C) loss factors for the full historic period have been produced by the AESO using the new LLR, nor has any alternative or supplemental mechanism for determining retrospective adjustments been established by the AUC. It is unclear when such loss factors will be made available, and the timing of a Module C decision remains unknown. Capital Power may incur material additional transmission charges on a go-forward basis but a provision has not been recorded in the Company's unaudited condensed interim consolidated financial statements since the outcome of the LLR Proceeding is not known.

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.

TRANSACTIONS WITH RELATED PARTIES

EPCOR was a related party of Capital Power until April 2, 2015, following the secondary offering and exchange of exchangeable common limited partnership units which decreased EPCOR's interest in the Company to 9.1%. The City of Edmonton, as the sole shareholder of EPCOR, was also a related party of Capital Power until April 2, 2015.

Power sales and purchases of energy, fuel, raw materials and other services transactions with EPCOR and the City of Edmonton were in the normal course of operations and were recorded at exchange amounts based on normal commercial rates. CPLP paid distributions to EPCOR for the three months ended March 31, 2015 based on EPCOR's unitholdings during that period.

(unaudited, $millions)	**Period from January 1, 2015 to April 2, 2015**
Revenues – energy sales:	
EPCOR and City of Edmonton	5
Purchase of raw materials and other services:	
EPCOR	2
Finance expense:	
EPCOR	5
CPLP distributions paid [1]	
EPCOR	7
Repayment of unsecured senior debt payable	
EPCOR	9

[1] Distributions of $6 million were paid on April 30, 2015 based on EPCOR's unitholdings outstanding as of March 31, 2015.

RISKS AND RISK MANAGEMENT

There have been no material changes in the six months ended June 30, 2016 to the Company's business and operational risks as described in the Company's December 31, 2015 MD&A.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $199 million as at June 30, 2016 ($184 million as at December 31, 2015) for its generation plants and the Genesee coal mine as it is obligated to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. Decommissioning provisions for the coal mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation. The timing of reclamation activities could be accelerated and the amount of decommissioning provisions could change on enactment of the CLP.

The Company is obligated under contract to purchase environmental credits totalling approximately $219 million in the current and future years and expects to mostly use these credits to comply with applicable environmental regulations, including the proposed CCR.

USE OF JUDGMENTS AND ESTIMATES

In preparing the condensed interim consolidated financial statements, management made necessary estimates in determining transaction amounts and financial statement balances. There have been no significant changes to the Company's use of judgments and estimates as described in the Company's December 31, 2015 MD&A.

ACCOUNTING CHANGES

Effective January 1, 2016

The Company adopted new accounting standards as issued by the International Accounting Standards Board (IASB). The changes and impact to Capital Power are:

Standard	Description	Impact to Capital Power
Presentation of financial statements (amendments to IAS 1)	Amendments providing guidance on materiality and aggregation on the statements of financial position, clarification of presentation issues on the statements of income or loss and other comprehensive income or loss, and providing additional examples of ways of ordering notes.	There was no impact to the Company's interim financial statement disclosures and the Company expects an insignificant impact to annual financial statement disclosures.
Acquisition of an interest in a joint operation (amendments to IFRS 11)	Provides guidance on how a joint operator accounts for the acquisition of an interest in a joint operation that is a business. It requires a joint operator to account for such an acquisition by applying IFRS 3 Business Combinations and other standards, and disclosing the relevant information specified in those IFRSs for business combinations.	No immediate impact but would affect applicable future transactions.

Future

The IASB issued the following new standards and amendments to existing standards that were not yet effective as of June 30, 2016 and which may significantly impact Capital Power:

Standard	Description	Impact to Capital Power	Effective Date
Statement of Cash Flows (amendments to IAS 7)	Amendments issued to improve disclosures of changes in financing liabilities to allow users of financial statements to evaluate changes in liabilities arising from financing activities.	Capital Power is currently analyzing the requirements to determine how best to apply them. The amendments may require further disclosures with respect to cash and non-cash debt transactions.	Effective for annual periods beginning on or after January 1, 2017.
Revenue from contracts with customers (IFRS 15)	New standard on revenue recognition consisting of a single and comprehensive framework for revenue recognition to ensure consistent treatment for all transactions in all industries and capital markets.	May change the timing of revenue recognized from any contracts with a number of discrete performance obligations (multiple-element arrangements), require separate line disclosure of credit losses, and require more extensive disclosures on annual and interim basis.	Effective for annual periods beginning on or after January 1, 2018; early application permitted and to be applied retrospectively.
Financial instruments (IFRS 9)	New standard, replacing IAS 39, which addresses requirements for classification and measurement, impairment, hedge accounting and derecognition of financial assets and liabilities.	May change the measurement of certain financial instruments and the recording of expected credit losses. Capital Power is currently analyzing the requirements to determine how best to apply them, determine system requirements, and develop the required disclosures.	Effective for annual periods beginning on or after January 1, 2018; early application permitted.
Leases (IFRS 16)	New standard which replaces IAS 17 which addresses the recognition, measurement, presentation and disclosure of leases and provides a new approach to lessee accounting, requiring lessees to recognize assets and liabilities for all leases.	Will require the Company to recognize leased assets and leased obligations with respect to its lease arrangements for office space.	Effective for annual periods beginning on or after January 1, 2019. Early application is permitted if IFRS 15 has also been applied.

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at June 30, 2016 and December 31, 2015 were as follows:

(unaudited, $ millions)	Classification	Fair value hierarchy level [1]	June 30, 2016 Carrying amount	June 30, 2016 Fair value	December 31, 2015 Carrying amount	December 31, 2015 Fair value
Financial assets:						
Cash and cash equivalents	Loans and receivables	N/A	28	28	80	80
Trade and other receivables	Loans and receivables	N/A	164	164	190	190
Derivative financial instruments assets – current and non-current	Financial assets designated at fair value through income or loss	See below	214	214	220	220
Finance lease receivables	Loans and receivables	Level 2	678	799	689	786
Other financial assets	Loans and receivables	Level 2	8	8	12	12
Financial liabilities:						
Trade and other payables (excluding current portion of finance lease obligation)	Other financial liabilities	N/A	147	147	180	180
Derivative financial instruments liabilities – current and non-current	Financial liabilities designated at fair value through income or loss	See below	110	110	53	53
Finance lease obligation (including current portion disclosed within trade & other payables)	Other financial liabilities	Level 2	20	20	22	22
Loans and borrowings (including current portion)	Other financial liabilities	Level 2	1,552	1,576	1,615	1,623

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 performed using valuation techniques and models reviewed by the Company's commodity risk group and the calculations are reviewed by management.

Risk management and hedging activities

There have been no material changes in the six months ended June 30, 2016 to the Company's risk management and hedging activities as described in the Company's December 31, 2015 MD&A.

The derivative financial instruments assets and liabilities held at June 30, 2016 compared with December 31, 2015 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at June 30, 2016				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 2	45	96	55	9	205
	Level 3	-	9	-	-	9
		45	105	55	9	214
Derivative financial instruments liabilities	Level 2	(5)	(76)	-	(15)	(96)
	Level 3	(14)	-	-	-	(14)
		(19)	(76)	-	(15)	(110)
Net derivative financial instruments assets (liabilities)		**26**	**29**	**55**	**(6)**	**104**

(unaudited, $ millions)		As at December 31, 2015				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 2	64	72	68	5	209
	Level 3	-	11	-	-	11
		64	83	68	5	220
Derivative financial instruments liabilities	Level 2	(4)	(38)	-	(11)	(53)
Net derivative financial instruments assets (liabilities)		**60**	**45**	**68**	**(6)**	**167**

Commodity and foreign exchange derivatives designated as accounting hedges

Unrealized gains and losses for fair value changes on commodity and foreign exchange derivatives that qualify for hedge accounting are recorded in other comprehensive loss and, when realized, are reclassified to net income (loss) as revenues, energy purchases and fuel, or foreign exchange gains and losses. As a result of the termination of the Sundance PPA (see Significant Events), certain derivatives that were previously designated as accounting hedges were de-designated as the hedged transactions are no longer expected to occur. The Company performed a hedge effectiveness test before and after the de-designation and concluded no ineffectiveness was present. Unrealized gains and losses associated with these de-designated hedges began to flow through net income as revenues starting in the first quarter of 2016.

Commodity and interest rate 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 prices and their impact on the Alberta power portfolio. 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 losses on interest rate derivatives that are not designated as hedges for accounting purposes are recorded in net income as finance expense.

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, 2016 that have materially affected or are reasonably likely to materially affect the Company's disclosures of required information and internal control over financial reporting.

SUMMARY OF QUARTERLY RESULTS

(GWh)	Three months ended							
Electricity generation	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**
Total generation excluding Sundance PPA	3,707	3,898	3,929	3,687	3,553	3,398	3,204	3,220
Alberta commercial plants and Sundance PPA								
Genesee 3	474	474	500	498	491	493	369	473
Keephills 3	501	388	489	258	436	457	433	461
Clover Bar Energy Centre 1, 2 and 3	106	48	41	39	98	70	45	77
Joffre	21	83	84	62	76	86	58	77
Shepard	647	577	387	572	443	60	N/A	N/A
Halkirk	124	124	129	88	107	136	146	86
Clover Bar Landfill Gas	2	1	1	2	3	2	3	3
Alberta commercial plants – owned	1,875	1,695	1,631	1,519	1,654	1,304	1,054	1,177
Sundance PPA [1]	-	655	717	688	565	691	819	673
	1,875	2,350	2,348	2,207	2,219	1,995	1,873	1,850
Alberta contracted plants								
Genesee 1	770	843	842	865	608	815	857	854
Genesee 2	582	833	861	843	838	836	856	841
	1,352	1,676	1,703	1,708	1,446	1,651	1,713	1,695
Ontario and British Columbia contracted plants								
Island Generation	-	-	5	37	37	-	9	6
K2 Wind	34	71	102	46	19	N/A	N/A	N/A
Kingsbridge 1	16	34	36	13	21	31	35	14
Port Dover and Nanticoke	65	95	95	44	69	91	91	51
Quality Wind	90	91	121	97	82	108	101	71
	205	291	359	237	228	230	236	142
U.S. contracted plants								
Roxboro, North Carolina	82	66	77	76	70	59	74	73
Southport, North Carolina	144	127	131	128	118	129	122	133
Beaufort Solar, North Carolina	8	7	-	N/A	N/A	N/A	N/A	N/A
Macho Springs, New Mexico	41	36	28	19	37	25	5	N/A
	275	236	236	223	225	213	201	206

[1] The Company gave notice to terminate its role as Buyer of the Sundance PPA effective March 24, 2016 (see Significant Events). Results of the Sundance PPA were recognized up to March 24, 2016.

(%)	Three months ended							
Plant availability	**Jun 30 2016**	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**
Total average plant availability excluding Sundance PPA	90	97	99	95	90	98	94	97
Alberta commercial plants and Sundance PPA								
Genesee 3	100	99	100	100	100	100	74	97
Keephills 3	100	90	100	63	97	100	92	100
Clover Bar Energy Centre 1, 2 and 3	91	99	97	88	95	97	90	97
Joffre	55	89	100	100	87	99	82	95
Shepard	82	100	98	100	73	80	N/A	N/A
Halkirk	98	99	96	97	98	99	98	91
Clover Bar Landfill Gas	99	99	84	81	93	100	87	58
Alberta commercial plants – owned	87	96	98	92	89	97	87	96
Sundance PPA [1]	-	95	92	91	79	92	96	85
	87	96	96	92	86	95	91	91
Alberta contracted plants								
Genesee 1	95	100	99	100	72	98	100	100
Genesee 2	72	99	100	98	100	100	100	99
	84	99	100	99	86	99	100	99
Ontario and British Columbia contracted plants								
Island Generation	100	100	100	100	100	100	100	99
K2 Wind	99	99	99	98	98	N/A	N/A	N/A
Kingsbridge 1	97	94	98	94	95	97	96	93
Port Dover and Nanticoke	100	97	98	95	97	99	97	98
Quality Wind	98	99	98	94	97	98	98	93
	99	99	99	97	98	99	98	97
U.S. contracted plants								
Roxboro, North Carolina	100	89	99	94	87	97	100	100
Southport, North Carolina	92	83	93	94	88	89	88	85
Beaufort Solar, North Carolina	91	98	100	N/A	N/A	N/A	N/A	N/A
Macho Springs, New Mexico	98	97	96	96	99	99	99	N/A
	95	89	96	95	91	94	92	90

[1] The Company gave notice to terminate its role as Buyer of the Sundance PPA effective March 24, 2016 (see Significant Events). Results of the Sundance PPA were recognized up to March 24, 2016.

Financial results

(unaudited, $ millions)	Three months ended							
	Jun 30 2016	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**
Revenues								
Alberta commercial plants, Sundance PPA and portfolio optimization [1]	166	188	199	237	130	216	178	119
Alberta contracted plants	62	71	70	72	67	66	69	76
Ontario and British Columbia contracted plants	25	34	40	23	25	36	36	21
U.S. contracted plants	34	32	30	29	28	27	22	22
Corporate [2]	1	2	1	2	4	1	2	2
Unrealized changes in fair value of commodity derivatives and emission credits	(59)	14	1	106	(171)	12	125	8
	229	**341**	**341**	**469**	**83**	**358**	**432**	**248**
Adjusted EBITDA								
Alberta commercial plants, Sundance PPA and portfolio optimization [1]	71	64	70	72	49	63	60	49
Alberta contracted plants	43	42	45	52	45	42	41	44
Ontario and British Columbia contracted plants [3]	28	38	45	22	21	30	29	15
U.S. contracted plants	8	8	10	6	6	5	1	3
Corporate	(27)	(24)	(24)	(25)	(27)	(24)	(27)	(25)
Unrealized changes in fair value of commodity derivatives and emission credits	(15)	(8)	(12)	27	(47)	31	37	5
	108	**120**	**134**	**154**	**47**	**147**	**141**	**91**

1 The Company gave notice to terminate its role as Buyer of the Sundance PPA effective March 24, 2016 (see Significant Events). Results of the Sundance PPA were recognized up to March 24, 2016.

2 Revenues are offset by interplant category revenue eliminations.

3 Commencing with the first quarter of 2016, the reported Ontario and British Columbia contracted plants' adjusted EBTIDA was changed to include the adjusted EBITDA from joint venture and the applicable comparative periods have been adjusted to conform to the current period's presentation.

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

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Jun 30 2016	Mar 31 2016	Dec 31 2015	Sep 30 2015	Jun 30 2015	Mar 31 2015	Dec 31 2014	Sep 30 2014
Revenues	229	341	341	469	83	358	432	248
Adjusted EBITDA [1,2]	108	120	134	154	47	147	141	91
Net income (loss)	20	(8)	34	50	(48)	50	48	(57)
Net income (loss) attributable to shareholders of the Company	23	(6)	35	49	(34)	40	39	(45)
Basic earnings (loss) per share ($)	0.19	(0.11)	0.29	0.44	(0.39)	0.41	0.40	(0.62)
Normalized earnings per share ($) [1]	0.30	0.33	0.42	0.33	0.10	0.32	0.20	0.12
Funds from operations [1,3]	106	109	125	97	70	108	102	83
Purchase of property, plant and equipment and other assets	81	31	17	36	35	52	57	25

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

2 Commencing with the first quarter of 2016, the reported Ontario and British Columbia contracted plants' adjusted EBTIDA was changed to include the adjusted EBITDA from joint venture and the applicable comparative periods have been adjusted to conform to the current period's presentation.

3 Commencing with the Company's December 31, 2014 quarter-end, the reported funds from operations measure was changed to remove 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.

	Three months ended							
Spot price averages	Jun 30 2016	Mar 31 2016	Dec 31 2015	Sep 30 2015	Jun 30 2015	Mar 31 2015	Dec 31 2014	Sep 30 2014
Alberta power ($ per MWh)	15	18	21	26	57	29	30	64
Alberta natural gas (AECO) ($ per Gj)	1.34	1.72	2.35	2.77	2.52	2.63	3.43	3.81
Capital Power's Alberta portfolio average realized power price ($ per MWh)	61	52	55	61	46	59	58	56

Factors impacting results for the previous quarters

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

Financial results for the first quarter 2016 reflected the impact of lower Alberta power pricing averaging $18 per MWh. Revenues were lower compared with the corresponding period in 2015 mainly due to lower Alberta average spot prices and lower average realized price on the Alberta portfolio. Adjusted EBITDA decreased quarter over quarter mainly due to unrealized losses recognized on commodity derivatives and emission credits held for trading. Adjusted EBITDA was also negatively impacted by increased environmental compliance costs resulting from higher contributions to the Climate Change and Emissions Fund and decreased generation at Quality Wind. The Company exercised its right to terminate the Sundance PPA effective March 24, 2016. As a result, Capital Power's first quarter net income was negatively impacted by a non-cash $53 million pre-tax loss with respect to the derecognition of the Sundance PPA intangible asset.

For the quarter ended December 31, 2015, the Company recorded net income attributable to shareholders of $35 million and normalized earnings per share of $0.42, compared to $39 million and $0.20 respectively for the quarter ended December 31, 2014. Net income attributable to common shareholders was lower for the quarter compared to the same quarter in 2015 primarily due to lower adjusted EBITDA, increased depreciation on new assets and finance expense on additional plant financing, partially offset by the contribution of K2 equity earnings and lower taxes. Generating plants contributed higher adjusted EBITDA for the fourth quarter with higher generation across the fleet, including fully hedged Alberta baseload units, the addition of Shepard and a full quarter of Macho Springs compared to the same quarter last year. These additions were more than offset by the quarter over quarter decrease in unrealized changes in the fair value of derivative contracts. In the fourth quarter of 2014, the Company reported unrealized gains of $37 million due to declining forward prices on its forward sales contracts. In the fourth quarter of 2015, the Company reported unrealized losses on its forward electricity sales contracts upon reversal of prior quarter gains and declining prices on its long natural gas position. Normalized earnings per share of $0.42 in the fourth quarter of 2015 was higher than the comparable amount of $0.20 in the fourth quarter of 2014 primarily due to the increase in adjusted EBITDA after removing the effects of unrealized changes in fair value of derivative contracts.

The results for the third quarter of 2015 reflected strong portfolio optimization results due to the forward sale of 100%

of its commercial production, realizing a price of $61 per MWh compared with the $26 per MWh Alberta spot power price average for the three months ended September 30, 2015. Alberta commercial plant results reflected the Keephills 3 planned outage and an unplanned outage at Clover Bar Energy Centre Unit 2. The Alberta electricity portfolio accounted for unrealized net gains of $27 million due to decreasing Alberta forward prices combined with the portfolio's net forward sales contracts.

The results for the second quarter of 2015 reflected volatility in Alberta power prices where spot prices averaged $97 per MWh in June due to warmer weather compared with $21 per MWh in April 2015 and $54 per MWh in May 2015. The positive EBITDA realized by the Alberta plants was partly offset by portfolio optimization results. With commercial production 100% sold forward in the quarter, the Company was required to cover a short market position at higher prices. Capital Power's second quarter 2015 results were also negatively impacted by the announcement of an increase to the Alberta statutory income tax rate, which resulted in $19 million of additional income tax expense for the quarter. The Alberta government also announced changes to Alberta's regulations governing carbon emissions with increases to the required reduction in emissions intensity and cost of compliance. Capital Power announced a 7.4% increase in the annual dividend for holders of its common shares commencing with the third quarter dividend paid on October 30, 2015.

The results for the quarter ended March 31, 2015 reflected the impact of low Alberta power pricing averaging $29 per MWh. Alberta commercial plant results reflected the commencement of operations at Shepard. Portfolio optimization results were strong since the Company was fully hedged at an average realized price of $59 per MWh. The Alberta electricity portfolio accounted for unrealized net gains of $21 million due to decreasing Alberta forward prices combined with the portfolio's net forward sales contracts.

The results for the quarter ended December 31, 2014 reflected the Genesee 3 major planned outage and the impact of low Alberta power pricing averaging $30 per MWh. Portfolio optimization revenues were strong since the Company hedged a greater portion of its baseload generation by entering into more contracts. Captured prices realized through portfolio optimization were greater than spot prices during the fourth quarter of 2014. Alberta commercial plant results included an $8 million recovery on settlement of a claim with a turbine supplier relating to a component failure at Genesee 3 in 2008. Adjusted EBITDA for the Alberta contracted plants was negatively impacted by costs associated with the wind-up of the Genesee coal mine's defined benefit pension plan. Significant events during the quarter were the acquisition of renewable development sites and the receipt of all major regulatory approvals for Genesee 4 and 5.

Financial results for the third quarter of 2014 reflected the impact of an extended planned outage and other unplanned outages at the Sundance PPA units and derates at the Keephills 3 plant. The outages occurred primarily in July 2014 coinciding with a period of pricing volatility with Alberta spot power prices in July, averaging $122 per MWh compared with $45 per MWh in August 2014 and $24 per MWh in September 2014. With commercial production 100% sold forward in July 2014, the resulting short position was covered at the higher prices. Capital Power's third quarter 2014 net income was also negatively impacted by a non-cash write-down of deferred tax assets of $73 million. The write-down related to the accounting impact of U.S. income tax loss carryforwards that could no longer be recognized for accounting purposes based on the Company's long-term forecast for U.S. taxable income.

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

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

	Three months ended							
	Jun 30 2016	**Mar 31 2016**	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**
Share price ($/common share)								
High	20.23	18.93	20.21	22.42	25.58	27.12	28.14	28.71
Low	17.31	16.37	15.41	18.28	21.53	23.77	24.50	25.75
Close	19.28	18.00	17.77	18.88	21.54	24.51	26.00	26.75
Volume of shares traded (millions)	14.8	19.2	20.5	19.4	21.1	18.8	13.9	12.5

Outstanding share and partnership unit data

As at July 19, 2016, the Company had 96.134 million common shares outstanding, 5 million Cumulative Rate Reset Preference Shares, Series 1 outstanding, 6 million Cumulative Rate Reset Preference Shares, Series 3, 8 million Cumulative Rate Reset Preference Shares, Series 5, and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares as at July 19, 2016 were 100.320 million. The outstanding special limited voting share is held by EPCOR.

As at July 19, 2016, CPLP had 21.750 million general partnership units outstanding and 80.953 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held, indirectly, 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, 2016 and 2015

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Revenues	$ 229	$ 83	$ 570	$ 441
Energy purchases and fuel (note 8)	(45)	42	(200)	(100)
Gross margin	184	125	370	341
Other raw materials and operating charges	(31)	(29)	(57)	(47)
Staff costs and employee benefits expense	(31)	(30)	(63)	(62)
Depreciation and amortization	(54)	(55)	(110)	(106)
Loss on termination of power purchase arrangement (note 4)	-	-	(53)	-
Other administrative expense	(23)	(21)	(42)	(40)
Foreign exchange (loss) gain	(1)	1	7	(7)
Operating income (loss)	44	(9)	52	79
Finance expense	(19)	(24)	(41)	(42)
Income from joint venture	5	1	13	1
Income (loss) before tax	30	(32)	24	38
Income tax expense (note 5)	(10)	(16)	(12)	(36)
Net income (loss)	$ 20	$ (48)	$ 12	$ 2
Attributable to:				
Non-controlling interests	$ (3)	$ (14)	$ (5)	$ (4)
Shareholders of the Company	$ 23	$ (34)	$ 17	$ 6
Earnings (loss) per share (attributable to common shareholders of the Company):				
Basic (note 7)	$ 0.19	$ (0.39)	$ 0.07	$ (0.06)
Diluted (note 7)	$ 0.19	$ (0.39)	$ 0.07	$ (0.06)

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Net income (loss)	$ 20	$ (48)	$ 12	$ 2
Other comprehensive loss:				
Items that are or may be reclassified subsequently to net income (loss):				
Cash flow hedges:				
Unrealized (losses) gains on derivative instruments[1]	(18)	(94)	19	(38)
Unrealized (losses) gains on derivative instruments – joint venture[2]	(5)	5	(8)	(3)
Reclassification of (gains) losses on derivative instruments to income for the period[3]	(19)	7	(49)	(14)
Net investment in foreign subsidiaries:				
Unrealized (loss) gain[4]	(1)	(2)	(13)	14
Total items that are or may be reclassified subsequently to net income (loss), net of tax	(43)	(84)	(51)	(41)
Total other comprehensive loss, net of tax	(43)	(84)	(51)	(41)
Total comprehensive loss	$ (23)	$ (132)	$ (39)	$ (39)
Attributable to:				
Non-controlling interests	$ (3)	$ (25)	$ (5)	$ (6)
Shareholders of the Company	$ (20)	$ (107)	$ (34)	$ (33)

[1] For the three and six months ended June 30, 2016, net of income tax recovery of $6 million and income tax expense of $7 million respectively. For the three and six months ended June 30, 2015, net of income tax recovery of $27 million and $12 million respectively.

[2] For the three and six months ended June 30, 2016, net of income tax recovery of $2 million and $3 million respectively. For the three and six months ended June 30, 2015, net of income tax expense of $2 million and income tax recovery of $1 million respectively.

[3] For the three and six months ended June 30, 2016, net of reclassification of income tax expense of $7 and $18 respectively. For the three and six months ended June 30, 2015, net of reclassification of income tax expense of nil and $6 million respectively.

[4] For the three and six months ended June 30, 2016 and June 30, 2015, 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, 2016	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 28	$ 80
Trade and other receivables	164	190
Inventories	90	99
Derivative financial instruments assets (note 8)	101	93
	383	462
Non-current assets:		
Other assets	20	24
Derivative financial instruments assets (note 8)	113	127
Finance lease receivables	678	689
Other financial assets	9	13
Deferred tax assets	15	18
Equity-accounted investment	-	10
Intangible assets (note 4)	289	341
Property, plant and equipment	3,680	3,679
Goodwill	28	30
Total assets	$ 5,215	$ 5,393
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 148	$ 181
Derivative financial instruments liabilities (note 8)	41	27
Loans and borrowings	201	339
Deferred revenue and other liabilities	6	2
Provisions	17	22
	413	571
Non-current liabilities:		
Derivative financial instruments liabilities (note 8)	69	26
Loans and borrowings	1,351	1,276
Finance lease obligation	19	21
Deferred revenue and other liabilities	94	97
Deferred tax liabilities	365	376
Provisions	229	210
	2,127	2,006
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 9)	2,722	2,744
Deficit	(133)	(70)
Other reserves	23	74
Deficit and other reserves	(110)	4
	2,612	2,748
Non-controlling interests	63	68
Total equity	2,675	2,816
Total liabilities and equity	$ 5,215	$ 5,393

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	Cash flow hedges[1]	Cumulative translation account[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, 2016	$ 2,744	$ 42	$ 31	$ (9)	$ 10	$ (70)	$ 2,748	$ 68	$ 2,816
Net income (loss)	-	-	-	-	-	17	17	(5)	12
Other comprehensive loss:									
Cash flow derivative hedge gains	-	26	-	-	-	-	26	-	26
Cash flow derivative hedge losses – joint venture	-	(11)	-	-	-	-	(11)	-	(11)
Reclassification of gains to net income	-	(67)	-	-	-	-	(67)	-	(67)
Unrealized loss on foreign currency translation	-	-	(13)	-	-	-	(13)	-	(13)
Tax on items recognized directly in equity	-	14	-	-	-	-	14	-	14
Other comprehensive loss	$ -	$ (38)	$ (13)	$ -	$ -	$ -	$ (51)	$ -	$ (51)
Total comprehensive loss	-	(38)	(13)	-	-	17	(34)	(5)	(39)
Common share dividends (note 9)	-	-	-	-	-	(70)	(70)	-	(70)
Preferred share dividends (note 9)	-	-	-	-	-	(10)	(10)	-	(10)
Common shares purchased	(22)	-	-	-	-	-	(22)	-	(22)
Equity as at June 30, 2016	$ 2,722	$ 4	$ 18	$ (9)	$ 10	$ (133)	$ 2,612	$ 63	$ 2,675

[1] Accumulated other comprehensive income. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income 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	Cash flow hedges[1]	Cumulative translation account[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2015	$ 2,391	$ 40	$ (1)	$ (13)	$ 9	$ 25	$ 2,451	$ 552	$ 3,003
Net income (loss)	-	-	-	-	-	6	6	(4)	2
Other comprehensive (loss) income :									
Cash flow derivative hedge losses	-	(50)	-	-	-	-	(50)	-	(50)
Cash flow derivative hedge losses – joint venture	-	(4)	-	-	-	-	(4)	-	(4)
Reclassification of gains to net loss	-	(20)	-	-	-	-	(20)	-	(20)
Unrealized gain on foreign currency translation	-	-	14	-	-	-	14	-	14
Tax on items recognized directly in equity	-	19	-	-	-	-	19	-	19
Attributed to non-controlling interests	-	2	-	-	-	-	2	(2)	-
Other comprehensive (loss) income	$ -	$ (53)	$ 14	$ -	$ -	$ -	$ (39)	$ (2)	$ (41)
Total comprehensive (loss) income	-	(53)	14	-	-	6	(33)	(6)	(39)
Issue of share capital	449	-	-	-	-	-	449	-	449
Distributions to non-controlling interests	-	-	-	-	-	-	-	(6)	(6)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	2	2
Change in non-controlling interests ownership	-	(5)	-	-	-	28	23	(473)	(450)
Tax on change in non-controlling interests ownership	-	(3)	-	-	-	(56)	(59)	-	(59)
Common share dividends (note 9)	-	-	-	-	-	(63)	(63)	-	(63)
Preferred share dividends (note 9)	-	-	-	-	-	(11)	(11)	-	(11)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Dividends reinvested (note 9)	22	-	-	-	-	-	22	-	22
Common shares purchased	(38)	-	-	-	-	-	(38)	-	(38)
Share-based payment	-	-	-	-	1	-	1	-	1
Share options exercised	2	-	-	-	-	-	2	-	2
Equity as at June 30, 2015	$ 2,826	$ (21)	$ 13	$ (13)	$ 10	$ (72)	$ 2,743	$ 69	$ 2,812

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

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Six months ended June 30, 2016	2015
Cash flows from operating activities:		
Net income	$ 12	$ 2
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Loss on termination of power purchase arrangement (note 4)	53	-
Depreciation and amortization	110	106
Finance expense	41	42
Fair value changes on commodity derivative instruments and emission credits held for trading	23	16
Unrealized foreign exchange (gain) loss	(6)	7
Income tax expense	12	36
Income from joint venture	(13)	(1)
Other items	(6)	(6)
Change in fair value of derivative instruments reflected as cash settlement	(13)	(22)
Distribution received from joint venture	17	-
Finance lease receivable collected	10	10
Interest paid[1]	(41)	(34)
Income taxes paid[2]	(1)	(1)
Change in non-cash operating working capital	3	(34)
Net cash flows from operating activities	201	121
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(112)	(87)
Other cash flows from investing activities	9	10
Change in non-cash investing working capital	(9)	21
Net cash flows used in investing activities	(112)	(56)
Cash flows used in financing activities:		
Proceeds from issue of loans and borrowings	115	57
Repayment of loans and borrowings	(146)	(38)
Proceeds from exercise of share options	-	1
Common shares purchased	(22)	(38)
Distributions paid to non-controlling interests	-	(12)
Common share dividends paid (note 9)	(71)	(35)
Preferred share dividends paid (note 9)	(10)	(11)
Capitalized interest paid[1]	(1)	(8)
Income taxes paid[2]	(4)	(5)
Net cash flows used in financing activities	(139)	(89)
Foreign exchange (loss) gain on cash held in a foreign currency	(2)	3
Net decrease in cash and cash equivalents	(52)	(21)
Cash and cash equivalents at beginning of period	80	71
Cash and cash equivalents at end of period	$ 28	$ 50

[1] Total interest paid.

[2] Total income taxes paid.

See accompanying notes to the condensed interim consolidated financial statements

1. Reporting entity:

Capital Power Corporation (the Company or Capital Power) builds, owns and operates power plants 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 2015 annual consolidated financial statements prepared in accordance with International Financial Reporting Standards (IFRS).

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

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on July 22, 2016.

3. Changes in accounting policies:

Effective January 1, 2016, the Company has adopted the following amendments:

IAS 1 – Presentation of Financial Statements (Amendment) – The objective of the amendments is to improve the presentation and disclosure in financial reports by providing guidance on materiality, clarifying presentation issues related to the statement of financial position, statement of income and other comprehensive income or loss and providing additional examples of possible ways of ordering notes. The amendments did not change the presentation and disclosure within the condensed interim consolidated financial statements as previous treatment applied by the Company was aligned with the amendments.

IFRS 11 – Acquisition of an Interest in Joint Operations (Amendment) – The objective of the amendments issued is to improve comparability of reported financial information by providing guidance on how a joint operator accounts for the acquisition of an interest in a joint operation, in which the activity of the operation constitutes a business. It would require a joint operator to account for such an acquisition by applying IFRS 3 – Business Combinations and other standards, and disclosing the relevant information specified in those IFRSs for business combinations. The amendments to IFRS 11 will affect applicable future transactions.

4. Loss on termination of power purchase arrangement:

On March 24, 2016, Capital Power notified the Balancing Pool of the Company’s decision to terminate its role as Buyer of the Sundance C Power Purchase Arrangement (Sundance PPA) effective March 24, 2016. As a result, no further economic benefits are expected from the Sundance PPA and the related intangible asset was derecognized. The Company has recorded a pre-tax non-cash loss of $53 million ($46 million post-tax) with respect to the derecognition of the Sundance PPA intangible asset. Effective March 24, 2016, the Company also de-designated certain energy cash flow hedges related to forecasted transactions no longer expected to occur as a result of the Sundance PPA termination, which resulted in the reclassification of unrealized gains of $5 million ($4 million post-tax) from other comprehensive loss to net income. No hedge ineffectiveness resulted from the de-designation of the cash flow hedges.

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

4. Loss on termination of power purchase arrangement, continued:

As at July 22, 2016, Capital Power has not received acceptance of the Sundance PPA termination or of the effective termination date from the Balancing Pool. The Balancing Pool and Capital Power could differ in opinion as to the effective date of termination which, in the event that the termination date is determined to be later than the March 24, 2016 termination notification date, may result in an estimated additional loss of up to $26 million as at June 30, 2016 pertaining to the total Sundance PPA. Of this estimated loss, Capital Power's 52% share of up to $13 million as at June 30, 2016 would be recognized in the Company's consolidated statements of income (loss) in the event that the termination date is determined to be later than the March 24, 2016 termination notification date. The calculation of the estimated loss is based on several key assumptions, including output generated by the Sundance PPA units during the period, Alberta power prices that settled during the period, emission intensity factors, and other fixed payment terms as specified in the Sundance PPA. Although there can be no assurance that the termination date will be accepted as filed by the Company, the Company does not believe that the resulting outcome will have a material adverse impact on its financial position.

5. Income tax:

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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Income (loss) before tax	$ 30	$ (32)	$ 24	$ 38
Income tax at the statutory rates of 27% (2015 – 26.0%)	8	(8)	6	10
Increase (decrease) resulting from:				
Non-deductible amounts	-	-	5	-
Amounts attributable to non-controlling interests	1	4	2	2
Change in unrecognized tax benefits	-	1	(1)	4
Statutory and other rate differences	-	17	(2)	18
Other	1	2	2	2
Income tax expense	$ 10	$ 16	$ 12	$ 36

6. Impairment testing:

Property, plant and equipment and definite life intangible assets

The uncertainty created by the Climate Leadership Plan (CLP) announced on November 22, 2015 by the Alberta Government (the Government), combined with the impact of low Alberta power prices and general negative market reaction to Alberta's economic conditions led to a substantial decline in the Company's market capitalization, particularly in the last quarter of 2015. As a result, the Company's Alberta Commercial and Alberta Contracted cash-generating units (together referred to as the Alberta CGUs) were tested for impairment during the fourth quarter of 2015 using valuation techniques, inputs, and assumptions as described in the Company's 2015 annual consolidated financial statements. No impairment was recorded to the Alberta CGUs as at December 31, 2015.

During the six months ended June 30, 2016, the Company's market capitalization continued to be below the book value of its net assets, which management concluded was a continuation of the factors described above. Accordingly, there have been no material changes to the previous management assessment performed in the fourth quarter of 2015.

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

6. Impairment testing, continued:

Property, plant and equipment and definite life intangible assets, continued

On March 16, 2016, the Government announced the appointment of a facilitator to support the phase out of coal (Facilitator) as proposed under the CLP. The Facilitator's scope of work includes advising the Government on options for phasing out coal-fired electricity emissions by 2030 that will maintain both the reliability of Alberta's electricity grid and stability of prices for consumers, while avoiding unnecessarily stranding capital assets. The Company anticipates the Facilitator's work to be completed in the second half of 2016. Capital Power will continue to monitor its market capitalization and re-assess potential impairments arising from the early plant closures once there is reasonable certainty in respect of compensation.

7. Earnings (loss) per share:

Basic earnings (loss) per share

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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Income (loss) for the period attributable to shareholders of the Company	$ 23	$ (34)	$ 17	$ 6
Preferred share dividends of the Company [1]	(5)	(6)	(10)	(12)
Earnings (loss) used in the calculation of basic earnings (loss) per share	$ 18	$ (40)	$ 7	$ (6)

[1] Includes preferred share dividends and related taxes in respect of the three and six months ended June 30, 2016 and 2015 respectively.

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	96,138,650	102,049,876	96,293,747	92,946,100

Diluted earnings (loss) per share

The earnings (loss) used in the calculation of diluted earnings (loss) per share are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Earnings (loss) used in the calculation of basic earnings (loss) per share	$ 18	$ (40)	$ 7	$ (6)
Effect of exchangeable limited partnership units issued to EPCOR for common shares [2]	-	-	-	-
Earnings (loss) used in the calculation of diluted earnings per share	$ 18	$ (40)	$ 7	$ (6)

[2] The exchangeable limited partnership units issued to EPCOR Utilities Inc. (EPCOR) were exchangeable for common shares of Capital Power on a one-for-one basis. For the three and six months ended June 30, 2016, the potential exchange of such units for common shares of the Company was not included in the calculation of diluted loss per share, as EPCOR exchanged all of its outstanding exchangeable limited partnership units for common shares of Capital Power on April 2, 2015. The unit exchange was included in the calculation of the Company's basic loss per share for the three months ended June 30, 2015. For the six months ended June 30, 2015, the potential exchange of such units for common shares of the Company was not included in the calculation of diluted earnings per share as it was anti-dilutive during the first quarter of 2015.

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

7. Earnings (loss) per share, continued:

The weighted average number of common shares for the purposes of diluted earnings (loss) per share reconciles to the weighted average number of common shares used in the calculation of basic earnings (loss) per share as follows:

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	96,138,650	102,049,876	96,293,747	92,946,100
Effect of dilutive share purchase options[3]	23,025	-	-	-
Weighted average number of common shares used in the calculation of diluted earnings (loss) per share	96,161,675	102,049,876	96,293,747	92,946,100

[3] For the three months ended June 30, 2016, the average market price of the Company's common shares exceeded the exercise price of certain granted share purchase options, but had a neutral effect on earnings per share. For the six months ended June 30, 2016, the average market price of the Company's common shares was below the exercise price of all granted share purchase options and as a result none of the share purchase options had a dilutive effect on earnings per share. For the three and six months ended June 30, 2015, the average market price of the Company's common shares exceeded the exercise price of certain granted share purchase options, but since the assumed exercise of the stock options decreased the basic loss per share, the options did not have a dilutive effect.

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

8. Derivative financial instruments and hedge accounting:

Derivative financial and non-financial instruments are held for the purpose 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, 2016				
	Energy and emission allowances		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 29	$ 68	$ 2	$ 2	$ 101
Non-current	16	37	53	7	113
Derivative instruments liabilities:					
Current	(2)	(39)	-	-	(41)
Non-current	(17)	(37)	-	(15)	(69)
Net fair value	$ 26	$ 29	$ 55	$ (6)	$ 104
Net notional (sells) buys (millions):					
Megawatt hours of electricity	(15)	(8)			
Gigajoules of natural gas		25			
Metric tons of emission allowances		1			
Number of renewable energy certificates		(2)			
Cross currency swaps and interest rate swaps (U.S. dollars)			$ 195	$ 100	
Interest rate swaps (Canadian dollars)				$ 200	
Range of remaining contract terms in years [1]	0.2 to 11.0	0.1 to 7.5	5.0 to 10.0	3.9 to 6.9	

[1] Terms of certain foreign exchange cash flow hedge contracts and interest rate non-hedge contracts require settlement in 2.0 years and 3.9 years respectively. The remaining years of the underlying derivatives of these contracts are reflected in the table above.

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

8. Derivative financial instruments and hedge accounting, continued:

	December 31, 2015				
	Energy and emission allowances		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 42	$ 51	$ -	$ -	$ 93
Non-current	22	32	68	5	127
Derivative instruments liabilities:					
Current	(2)	(25)	-	-	(27)
Non-current	(2)	(13)	-	(11)	(26)
Net fair value	$ 60	$ 45	$ 68	$ (6)	$ 167
Net notional (sells) buys (millions):					
Megawatt hours of electricity	(8)	(3)			
Gigajoules of natural gas		19			
Metric tons of emission allowances		2			
Number of renewable energy certificates		(2)			
Cross currency swaps and interest rate swaps (U.S. dollars)			$ 195	$ 100	
Interest rate swaps (Canadian dollars)				$ 200	
Range of remaining contract terms in years [2]	0.1 to 4.0	0.1 to 5.3	5.5 to 10.5	4.4 to 7.4	

[2] Terms of certain foreign exchange cash flow hedge contracts and interest rate non-hedge contracts require settlement in 2.5 years and 4.4 years respectively. The remaining years of the underlying derivatives of these contracts are reflected in the table above.

Except as disclosed in note 10, the fair values of derivative instruments are determined using valuation techniques, inputs, and assumptions as described in the Company's 2015 annual consolidated financial statements. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

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

	Three months ended June 30, 2016		Three months ended June 30, 2015	
	Unrealized (losses) gains	Realized gains	Unrealized losses	Realized (losses) gains
Energy cash flow hedges	$ (53)	$ 26	$ (110)	$ (8)
Energy and emission allowances non-hedges	(15)	38	(46)	(8)
Foreign exchange cash flow hedges[3]	3	1	(3)	-
Interest rate non-hedges	(1)	-	-	1

[3] For the three months ended June 30, 2016, unrealized losses of $1 million (three months ended June 30, 2015 – unrealized losses of $4 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive loss to net income (loss) to offset the impact to unrealized foreign exchange gains from the revaluation of U.S. dollar denominated loans and borrowings.

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

8. Derivative financial instruments and hedge accounting, continued:

	Six months ended June 30, 2016		Six months ended June 30, 2015	
	Unrealized (losses) gains	Realized gains	Unrealized losses	Realized gains
Energy cash flow hedges	$ (45)	$ 62	$ (69)	$ 20
Energy and emission allowances non-hedges	(20)	68	(15)	15
Foreign exchange cash flow hedges[4]	4	1	(1)	-
Interest rate non-hedges	-	-	(2)	1

[4] For the six months ended June 30, 2016, unrealized losses of $18 million (six months ended June 30, 2015 – unrealized gains of $17 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive loss to net income (loss) to offset the impact to unrealized foreign exchange gains and losses from the revaluation of U.S. dollar denominated loans and borrowings.

Realized and unrealized gains and losses relate only to financial derivative instruments. The following gains and losses are included in the Company's statements of income (loss) for the three and six months ended June 30, 2016 and 2015:

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Revenues	$ 35	$ (181)	$ 153	$ (34)
Energy purchases and fuel[5]	14	119	(43)	54
Foreign exchange (loss) gain	-	(4)	(17)	17
Finance expense	(1)	1	-	(1)

[5] For the three and six months ended June 30, 2016, energy purchases and fuel includes unrealized gains of $44 million and $22 million, respectively (three and six months ended June 30, 2015 – unrealized gains of $124 million and $143 million, respectively).

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices and currency risk relating to U.S. dollar denominated loans and borrowings. For the three and six months ended June 30, 2016, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statement of income was nil (three and six months ended June 30, 2015 – nil).

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

	June 30, 2016
Within one year	$ 31
Between 1 – 5 years	17
After more than 5 years	3
	$ 51

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

9. Share capital:

	Dividends declared							
	For the three months ended June 30,				For the six months ended June 30,			
	2016		2015		2016		2015	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.3650	$ 35	$ 0.3400	$ 34	$ 0.7300	$ 70	$ 0.6800	$ 63
Preference, Series 1 [1]	0.1913	1	0.2875	2	0.3826	2	0.5750	3
Preference, Series 3	0.2875	2	0.2875	2	0.5750	4	0.5750	4
Preference, Series 5	0.2813	2	0.2813	2	0.5626	4	0.5626	4

	Dividends paid							
	For the three months ended June 30,				For the six months ended June 30,			
	2016		2015		2016		2015	
	Per share	Total[1]	Per share	Total [2]	Per share	Total[1]	Per share	Total[1]
Common	$ 0.3650	$ 35	$ 0.3400	$ 29	$ 0.7300	$ 71	$ 0.6800	$ 57
Preference, Series 1	0.1913	1	0.2875	2	0.3826	2	0.5750	3
Preference, Series 3	0.2875	2	0.2875	2	0.5750	4	0.5750	4
Preference, Series 5	0.2813	2	0.2813	2	0.5626	4	0.5626	4

[1] The annual fixed dividend rate for the Series 1 shares was reset from 4.60% to 3.06% for a quarterly dividend of $0.1913 per share effective for the March 31, 2016 dividend payment.

[2] The Company suspended its dividend reinvestment plan for its common shares effective June 30, 2015 until further notice. As a result, all dividends on common shares for the three and six months ended June 30, 2016 were paid in cash. For the three and six months ended June 30, 2015, dividends paid on common shares consists of $17 million and $35 million paid in cash and $12 million and $22 million paid through the Company's dividend reinvestment plan as common shares issued, respectively.

During the three and six months ended June 30, 2016, the Company purchased and canceled 59,388 and 1,245,600, respectively, of its outstanding common shares (three and six months ended June 30, 2015 – 1,598,136) under its normal course issuer bid (NCIB) approved by the Toronto Stock Exchange (TSX) on March 25, 2015. The Company has an additional NCIB approved by the TSX on April 28, 2016 to purchase and cancel up to 8,600,000 of its outstanding common shares during the one year period from April 28, 2016 to April 27, 2017.

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

10. Financial instruments:

Fair values

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

The classification and measurement of the Company's other short-term financial instruments are consistent with the methodologies described in the Company's 2015 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 2015 annual consolidated financial statements. The classification, carrying amount and fair value of the Company's other financial instruments are summarized as follows:

		June 30, 2016		December 31, 2015	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Loans and receivables					
Other financial assets	Level 2	$ 8	$ 8	$ 12	$ 12
Finance lease receivables	Level 2	678	799	689	786
Other financial liabilities[1]					
Loans and borrowings	Level 2	1,552	1,576	1,615	1,623
Finance lease obligation	Level 2	20	20	22	22

[1] Includes current portion.

Fair value hierarchy

Fair value represents the Company's estimate of the price at which a financial instrument could be exchanged between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated statements of financial position are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The valuation techniques used by the Company in determining the fair value of its financial instruments are the same as those used as at December 31, 2015.

The fair value measurement of a financial instrument is included in only one of the three levels described in the Company's 2015 annual consolidated financial statements, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment which will affect the placement within the fair value hierarchy levels.

The Company's policy is to recognize transfers between levels as of the date of the event of change in circumstances that caused the transfer. There were no significant transfers between levels in the fair value hierarchy for the three and six months ended June 30, 2016 and the year ended December 31, 2015.

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

10. Financial instruments, continued:

Fair value hierarchy, continued

The table below presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated statements of financial position, classified using the fair value hierarchy described in the Company's 2015 annual consolidated financial statements.

	June 30, 2016			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 205	$ 9	$ 214
Derivative financial instruments liabilities	-	(96)	(14)	(110)

	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 209	$ 11	$ 220
Derivative financial instruments liabilities	-	(53)	-	(53)

Valuation techniques used in determination of fair values within Level 3

On April 21, 2016, the Company entered into a 10-year, fixed price contract to swap the market revenue of its Bloom Wind project's generation for a fixed annual payment for a 10-year term, which extends beyond a liquid trading period. As forward market prices are not available for the full period of this contract, its fair value is derived using a forecast based on internal modelling. Accordingly this financial instrument is classified as Level 3. In addition, as at June 30, 2016 and December 31, 2015, the Company holds a contract for the sale of renewable energy certificates (RECs) for which pricing beyond two years is not readily observable and therefore classified in Level 3 of the hierarchy.

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

	June 30, 2016	December 31, 2015
REC pricing (per certificate)	$0.35 to $0.45	$0.39 to $0.45
Power pricing (per MWh)	$18.50 to $32.55	n/a

Valuation process applied to Level 3

The valuation model used to calculate the fair value of the derivative financial instruments assets and liabilities within Level 3 is reviewed by the Company's commodity risk group and the calculation is reviewed by management. The valuation technique and the associated inputs are assessed on a regular basis for ongoing reasonability. The table below presents the impact to fair value of Level 3 derivative instruments based on reasonably possible alternative assumptions:

	June 30, 2016	December 31, 2015
REC pricing [1]	$ 2	$ 2
Power pricing [1]	4	n/a

[1] Increase or decrease to fair value calculated using a $1 per unit change.

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

10. Financial instruments, continued:

Fair value hierarchy, continued

Continuity of Level 3 balances

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

	Six months ended June 30, 2016	Year ended December 31, 2015
As at January 1 [1]	$ 11	$ 11
Unrealized and realized gains included in net income (loss) [2]	1	2
Unrealized and realized losses included in other comprehensive loss	(14)	-
Settlements [3]	(3)	(2)
As at end of period	$ (5)	$ 11
Total unrealized losses for the period included in other comprehensive loss	$ (14)	$ -
Total unrealized losses for the period included in net income (loss) [2]	$ (2)	$ -

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

[2] Gains are recorded in revenues.

[3] Relates to settlement of financial derivative instruments.

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

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

11. 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 and New Mexico), 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.

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

	Three months ended June 30, 2016				Three months ended June 30, 2015			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 201	$ 28	$ -	$ 229	$ 55	$ 28	$ -	$ 83
Revenues - inter-area	(4)	(16)	20	-	-	2	(2)	-
Total revenues	$ 197	$ 12	$ 20	$ 229	$ 55	$ 30	$ (2)	$ 83

	Six months ended June 30, 2016				Six months ended June 30, 2015			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 502	$ 68	$ -	$ 570	$ 380	$ 61	$ -	$ 441
Revenues - inter-area	5	(1)	(4)	-	3	2	(5)	-
Total revenues	$ 507	$ 67	$ (4)	$ 570	$ 383	$ 63	$ (5)	$ 441

	As at June 30, 2016			As at December 31, 2015		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,414	$ 266	$ 3,680	$ 3,452	$ 227	$ 3,679
Intangible assets	251	38	289	300	41	341
Goodwill	-	28	28	-	30	30
Other assets	18	2	20	22	2	24
	$ 3,683	$ 334	$ 4,017	$ 3,774	$ 300	$ 4,074

12. Subsequent event:

On July 22, 2016, the Company's Board of Directors approved an increase of 6.8% in the annual dividend to $1.56 per common share effective for the third quarter of 2016.

13. Comparative figures:

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