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Capital Power reports fourth quarter and year-end 2015 results

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released financial results for the fourth quarter and year ended December 31, 2015.

Funds from operations were $125 million in the fourth quarter of 2015, an increase of 23% from $102 million in the fourth quarter of 2014. Normalized earnings attributable to common shareholders in the fourth quarter of 2015 were $41 million, or $0.42 per share, compared with $17 million, or $0.20 per share, in the comparable period of 2014. Net income attributable to shareholders in the fourth quarter of 2015 was $35 million and basic earnings per share (attributable to common shareholders) were $0.29 compared with net income attributable to shareholders of $39 million and basic earnings per share of $0.40 (attributable to common shareholders) in the comparable period of 2014.

For the year ended December 31, 2015, funds from operations totaled $400 million compared with $362 million for the year ended December 31, 2014. Normalized earnings attributable to common shareholders were $111 million or $1.15 per share compared with $59 million or $0.72 per share for 2014. Net income attributable to shareholders in 2015 was $90 million and basic earnings per share (attributable to common shareholders) were $0.70 compared with net income attributable to shareholders of $46 million and basic earnings per share (attributable to common shareholders) of $0.28 in 2014.

“Capital Power’s fourth quarter 2015 results exceeded our expectations and were driven by excellent operational performance and strong Alberta commercial portfolio results,” said Brian Vaasjo, President and CEO of Capital Power. “We achieved an average plant availability of 99% in the fourth quarter and generated our highest electricity output in the past two years. Despite Alberta power prices averaging $21 per megawatt-hour (MWh) in the fourth quarter, our trading desk captured a realized average price of $55 per MWh through our hedging program. Overall, we generated funds from operations of $125 million in the fourth quarter, a 23% increase from the same period a year ago.”

“Despite the weak economic environment and regulatory uncertainty in Alberta, Capital Power continued to deliver on its corporate priorities in 2015,” said Mr. Vaasjo. “We achieved our annual operating and financial targets with average plant availability of 95% and generated funds from operations of $400 million that was in the upper end of our $365 to $415 million target range. We continued to strengthen our contracted cash flow profile by adding 505 megawatts of owned generation capacity to our fleet last year from three new facilities utilizing natural gas, wind and solar generation.”

“For 2016, we look forward to working with the Alberta government to discuss fair compensation for the proposed accelerated closure of coal-fired generating units by 2030, and develop implementation plans for their Climate Leadership Plan announced last November,” continued Mr. Vaasjo. “The timely, fair and appropriate outcomes of these issues for our investors would provide the basis for continuing to invest in Alberta, including the proposed Genesee 4 and 5 project.” The deadline to provide full notice to proceed to the turbine manufacturer for Genesee 4 and 5 has been extended by up to 90 days from the previous March 1, 2016 deadline.

Operational and Financial Highlights [1] (unaudited)	**Three months ended December 31**		**Year ended December 31**	
(millions of dollars except per share and operational amounts)	**2015**	**2014**	**2015**	**2014**
Electricity generation (excluding acquired Sundance power purchase arrangement (PPA)) (GWh)	3,929	3,204	14,567	12,376
Generation plant availability (excluding acquired Sundance PPA) (%)	99%	94%	95%	95%
Revenues	$ 341	$ 432	$ 1,251	$ 1,228
Adjusted EBITDA [2]	$ 121	$ 141	$ 461	$ 423
Net income	$ 34	$ 48	$ 86	$ 50
Net income attributable to shareholders of the Company	$ 35	$ 39	$ 90	$ 46
Basic and diluted earnings per share	$ 0.29	$ 0.40	$ 0.70	$ 0.28
Normalized earnings attributable to common shareholders [2]	$ 41	$ 17	$ 111	$ 59
Normalized earnings per share [2]	$ 0.42	$ 0.20	$ 1.15	$ 0.72
Net cash flows from operating activities	$ 115	$ 107	$ 420	$ 391
Funds from operations [2]	$ 125	$ 102	$ 400	$ 362
Purchase of property, plant and equipment and other assets	$ 17	$ 57	$ 140	$ 220
Dividends per common share, declared	$ 0.3650	$ 0.3400	$ 1.4100	$ 1.3100

1 The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the audited Consolidated Financial Statements for the year ended December 31, 2015.

2 Earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses, income from joint venture, and gains 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

Medium-term note exchange

On December 17, 2015, CPLP noteholders of issued and outstanding 4.85% medium-term notes due February 21, 2019 ("Series 3") and 5.276% medium-term notes due November 16, 2020 ("Series 1") (collectively, the "CPLP Notes") voted to exchange the CPLP Notes for an equal principal amount of newly issued medium-term notes of Capital Power (Note Exchange Transaction). The newly issued notes have terms and conditions that are the same as those attached to the CPLP Notes. The Note Exchange Transaction was successfully completed on December 18, 2015 and is expected to simplify the organizational structure, reduce reporting obligations, and result in efficiencies for CPLP while providing noteholders with better liquidity over time and structural enhancement. Effective January 1, 2016, as a result of the Note Exchange Transaction, CPLP is no longer a reporting issuer.

Preferred Shares (Series 1) conversion privilege and dividend rate notice

On December 1, 2015, Capital Power notified registered shareholders of the Company's Cumulative 5-Year Rate Reset Preference Shares, Series 1 (Series 1 Shares) of the conversion privilege and dividend rate notice. Series 1 shareholders had the right to elect to convert any or all of their Series 1 Shares into an equal number of Cumulative Floating Rate Preference Shares, Series 2 (Series 2 Shares). Following the conversion deadline on December 16, 2015, approximately 930,800 Series 1 Shares were tendered for conversion, which was less than the one million shares required for conversion into Series 2 Shares. Accordingly, there were no Series 2 Shares issued as at December 31, 2015. Effective December 31, 2015, the Annual Fixed Dividend Rate for the Series 1 Shares for the next five year period was reset from 4.60% to 3.06%.

Beaufort Solar begins commercial operation

On December 22, 2015, Capital Power's 15 MW Beaufort Solar facility was commissioned and commenced operating under a 15 year power purchase agreement with Duke Energy Progress LLC. The Company constructed the facility and then entered into a sale and leaseback agreement with an A-rated U.S. financial institution for proceeds of $46 million (US$35 million) and a lease term of 10 years with an option for extension at the end of the lease term. The lease is classified as a finance lease for accounting purposes. As a result, the gain on the sale of the facility of $5 million (US$4 million) was recognized as deferred revenue on the Company's Consolidated Statements of Financial Position and will be amortized over the term of the lease.

Dividend increase

On July 27, 2015, the Company announced that its Board of Directors approved a 7.4% increase in the annual dividend for holders of its common shares, from $1.36 per common share to $1.46 per common share. This increased common share dividend commenced with the third quarter 2015 quarterly dividend payment paid on October 30, 2015 to shareholders of record at the close of business on September 30, 2015.

Changes to Alberta's emissions regulations and the announcement of the Alberta Climate Leadership Plan

On June 25, 2015, the Alberta government announced changes to Alberta's regulations governing carbon emissions and a comprehensive review of Alberta's climate change policy. The changes to the Specified Gas Emitters Regulation (SGER) will increase the required reduction in emissions intensity from 12% to 15% in 2016 and 20% in 2017, and increase the cost of contributions to the Climate Change and Emissions Management Fund from $15 per tonne of greenhouse gases to $20 per tonne in 2016 and $30 per tonne in 2017.

On August 14, 2015, a five member panel, appointed by the Alberta Minister of Environment and Parks, was announced with a mandate to provide recommendations to the Alberta government on how to address climate change in Alberta. Capital Power actively participated in the consultation process that led to the Alberta Climate Leadership Plan (CLP) that was announced on November 22, 2015.

The CLP provides guidance in three primary areas that affect the Company: changes to the compliance requirements for coal emissions, procurement of target renewable generation, and the accelerated retirement of Alberta coal-fired generation. The CLP recommends that the existing SGER be replaced in 2018 with the CCR. Under the CCR, electricity generators will pay $30 per tonne of greenhouse gas emissions above an electricity sector performance standard, which has yet to be determined. Coal emissions from coal-fired generating plants will be zero by 2030, subject to release of final CLP legislation and ensuring Alberta electric system reliability. It is expected that two-thirds of the phased out coal-fired generation will be replaced by renewable generation. The Company's Genesee 1 and Genesee 2 units and its 50% interests in the Genesee 3 and Keephills 3 units are all affected by this recommendation of the CLP. The Alberta government has committed to treat workers, communities and affected companies fairly, and avoid stranding capital. The CLP recommends that Renewable Energy Credits (REC's) be offered through a competitive process to the developers of renewables projects. The CLP maintains Alberta's deregulated market structure with new generation outside the renewable procurement process to continue to be built based on price signals from the energy only market.

Capital Power expects that the increase in the Company's compliance costs under the CCR will be mitigated by higher wholesale power prices from owner's passing through the compliance costs and the use of its inventory of low-cost carbon offset credits. The projected incremental impact of the CCR, between 2018 and 2020, is an average annual increase of approximately $20 million in adjusted EBITDA. From 2021 to 2029, the projected annual impact to adjusted EBITDA is a decrease of approximately $100 million, due to increased compliance costs of the CCR due to the depletion of the Company's carbon offset inventory and the expiry of the Genesee 1 and Genesee 2 PPA's. Under the terms of those PPAs, any carbon offset costs as a result of a change in legislation (like the CCR) are and will be borne by the PPA holder, the Balancing Pool, until 2020. Thereafter, the full CCR cost for Genesee 1 and Genesee 2 will be borne by Capital Power. Although unrelated to the CCR, the decrease in adjusted EBITDA is expected to be more than offset by the sale of electricity from Genesee 1 and Genesee 2 into the Alberta wholesale market at prices which are expected to exceed the contracted price under the PPA. The contracted prices under the PPA are projected to be approximately $37 per MWh in 2020. These projections do not take into account the compensation to be received from the Alberta government for the accelerated closure of Alberta's coal-fired power plants and assume no actions by Capital Power to further reduce greenhouse gas emissions.

There are numerous uncertainties associated with the CLP. Most significantly, it represents a proposed framework that has not been substantively enacted in legislation and therefore the final legal form and substance of the CLP is unknown. The Alberta government has indicated that an independent facilitator and the Alberta Electric System Operator (AESO) will work with owners of coal-fired power generation to address compensation and develop a transition plan. The Company will work closely with the government, the facilitator and the AESO, and strive to ensure successful implementation of government policies for the electricity sector and our investors. While the Company will employ its best efforts, there can be no assurance that the legislated process to replace coal-fired generation with renewables will not disrupt the effective functioning of Alberta merchant power market and there can be no assurance that the Company will be appropriately and sufficiently compensated for the potential early retirement of its coal assets.

K2 Wind begins commercial operation

On May 29, 2015, Capital Power, Samsung Renewable Energy Inc. and Pattern Energy Group LP announced that K2 Wind was fully operational and capable of generating 270 MW of electricity for the province of Ontario and would operate under a 20-year power purchase agreement with the Independent Electricity System Operator. Capital Power owns 90 MW or 33.3% of the capacity of this facility. Capital Power's share of final construction costs was $297 million, including both debt and equity financed components.

Secondary offering of Capital Power shares by EPCOR

On April 2, 2015, EPCOR exchanged all of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9.450 million of such common shares to the public pursuant to a secondary offering at $23.85 per common share. Capital Power did not receive any of the proceeds from EPCOR's sale of common shares. After giving effect to the exchange and the secondary offering, EPCOR owns approximately 9.1% of the common shares of Capital Power and no special voting shares of Capital Power or limited partnership units of CPLP. EPCOR has advised that it plans to eventually sell all or a substantial portion of its remaining interest in Capital Power, subject to market conditions, based on its requirements for capital and other circumstances that may arise in the future. In connection with the offering, the Registration Rights Agreement between Capital Power and EPCOR was terminated. Thus, the Company will no longer be obligated to assist EPCOR in making a secondary offering and any future sales of common shares by EPCOR will be completed by other means. As a result of EPCOR ceasing to hold special voting shares and EPCOR's ownership interest in Capital Power decreasing to below 10%, EPCOR no longer has the right, separately as a holder of special voting shares, to nominate and appoint any directors to Capital Power's Board of Directors.

This exchange and secondary offering by EPCOR and the medium-term note exchange discussed above will allow the Company to simplify the organization structure and reporting, and reduce costs associated with CPLP, including audit, legal, board, management and filing expenses.

Approval of normal course issuer bid and suspension of Dividend Re-investment Plan

On March 25, 2015, Capital Power's normal course issuer bid (NCIB) to purchase and cancel up to 5 million of its outstanding common shares during the one-year period from April 7, 2015 to April 6, 2016 was approved by the Toronto Stock Exchange (TSX). On November 27, 2015 the TSX approved an amendment to Capital Power's NCIB to purchase and cancel up to an additional 3,369,838 shares. Up to December 31, 2015, the Company purchased and cancelled approximately 6 million common shares totalling $121 million. Effective with the June 30, 2015 dividend, Capital Power suspended its Dividend Re-investment Plan (DRIP) for its common shares until further notice. Shareholders participating in the DRIP began receiving cash dividends as of the July 31, 2015 payment date.

Shepard begins commercial operation

On March 11, 2015, Capital Power and ENMAX announced that Shepard was fully operational and capable of generating over 800 MW of electricity to the Alberta grid. Capital Power became a 50% owner of this natural gas facility in 2012 and its final construction costs are expected to be $848 million which includes a performance bonus paid to the turbine manufacturer. The commercial arrangements with ENMAX include a 20-year tolling agreement where 75% of the Company's owned capacity is contracted from 2015 to 2017 and 50% thereafter to 2035.

Executive appointments

Capital Power and the Board of Directors announced the appointments of Bryan DeNeve to the executive position of Senior Vice President, Finance and Chief Financial Officer and Stuart Lee to the executive position of Senior Vice President Corporate Development and Commercial Services effective May 1, 2015. Mr. DeNeve and Mr. Lee formerly held the positions of Senior Vice President Corporate Development and Commercial Services and Senior Vice President, Finance and Chief Financial Officer, respectively.

The Company announced the appointment of Mark Zimmerman to the position of Senior Vice President, Corporate Development and Commercial Services effective November 2, 2015, to replace Mr. Lee who resigned from Capital Power effective August 31, 2015.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on February 19, 2016 at 12:00 noon (ET) to discuss the fourth quarter results. The conference call dial-in numbers are:

(604) 681-8564 (Vancouver)
(403) 532-5601 (Calgary)
(416) 623-0333 (Toronto)
(514) 687-4017 (Montreal)
(855) 353-9183 (toll-free from Canada and USA)

Participant access code for the call: 21543#

A replay of the conference call will be available following the call at: (855) 201-2300 (toll-free) and entering conference reference number 1192649# followed by participant code 21543#. The replay will be available until May 19, 2016.

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, funds from operations to net cash flows from operating activities and normalized earnings attributable to common shareholders to net income attributable to shareholders of the Company are contained in the Company's Management's Discussion and Analysis, prepared as of February 18, 2016, for the year ended December 31, 2015 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) impact to adjusted EBITDA as a result of the CLP, (ii) compensation to be received by the Company from the Government of Alberta in respect of the proposed early retirement of coal facilities and (iii) the structure and stability of Alberta's merchant power market.

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 February 18, 2016, for further discussion of these and other risks.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of February 18, 2016, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the years ended December 31, 2015 and December 31, 2014, the annual information form of Capital Power Corporation for the year ended December 31, 2015 and the cautionary statements regarding forward-looking information which begin on page 8. 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 years ended December 31, 2015, 2014 and 2013 is based on the audited consolidated financial statements of the Company which were prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors approved this MD&A as of February 18, 2016.

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FORWARD-LOOKING INFORMATION

Forward-looking information or statements included in this MD&A are provided to inform the Company's shareholders and potential investors about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this MD&A is generally identified by words such as will, anticipate, believe, plan, intend, target, and expect or similar words that suggest future outcomes.

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

- 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,
- the impact of environmental regulations on the Company, its businesses, accounting policies, and emissions compliance costs,
- compensation to be received by the Company from the Government of Alberta in respect of the proposed early retirement of coal facilities,
- carbon credits, and,
- future income taxes payable.

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 and Targets for 2016 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 for further discussion of these and other risks.

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

OVERVIEW OF BUSINESS AND CORPORATE STRUCTURE

Capital Power is a growth-oriented North American 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 owns 371 MW of capacity through its interest in the acquired Sundance power purchase arrangement (acquired Sundance PPA). An additional 530 MW of owned generation capacity is in advanced stages of development in Alberta.

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP), a subsidiary of the Company. As at December 31, 2015, the Company held 21.750 million general partnership units and 80.953 million common limited partnership units of CPLP which represented 100% of CPLP's total partnership units. Effective April 2, 2015, EPCOR (in this MD&A, EPCOR refers to EPCOR Utilities Inc. collectively with its subsidiaries) exchanged 18.841 million exchangeable common limited partnership units of CPLP for common shares of Capital Power Corporation (see Significant Events).

CORPORATE STRATEGY

Capital Power's corporate strategy is based on its vision to be recognized as one of North America's most respected, reliable and competitive power generators. The corporate strategy comprises the business strategy to operate as a competitive power producer and the financial strategy designed to provide consistent access to low-cost capital. The Company is committed to a position that provides for future dividend growth, an investment-grade credit rating supported by contracted cash flows, and a prudent expansion strategy.

(a) **Geographic focus** – Canada and the U.S. for contracted power generation and Alberta for merchant power generation.

(b) **Technology focus** – large-scale thermal technologies, renewable wind and solar facilities with a limited number of technologies and suppliers for each type of generation.

(c) **Financial strategy** – supportive of the business strategy; intended to provide access to cost competitive capital throughout the business cycle. This is facilitated by maintaining an investment grade credit rating with a stable and growing dividend. This requires a moderate risk profile where price volatility from merchant facilities is balanced with long-term contracted assets and hedging of merchant power price risk through forward sales.

(d) **Operational excellence** – safely manage, operate and maintain its power generation facilities in a manner that optimizes efficiency, productivity and reliability, and minimizes costs while reducing environmental impact.

(e) **Disciplined growth** – restricted to the geographic and technology focuses with specific financial hurdles and rigorous due diligence processes.

The Company continues to pursue growth in contracted power generation across North America as well as creating additional value in the Alberta market through power generation growth and portfolio trading strategies. During 2015, commercial operation of Shepard Energy Centre (Shepard), K2 Wind, and Beaufort Solar commenced (see Significant Events) and the Company continued its development plans for Genesee 4 and 5.

The Company is assessing a number of additional projects in various stages of development and it continues to evaluate acquisition prospects to strengthen its existing portfolio. To help ensure that the Company's growth strategy does not compromise its financial condition, it employs hurdle rates of return for acquisition and development project opportunities and evaluates them against the Company's current strategic plan. As part of the Company's growth strategy through developing and building new assets, the Company views power plant construction as a core competency.

PERFORMANCE OVERVIEW

The Company measures its performance in relation to its corporate strategy through financial and non-financial targets that are approved by the Board of Directors of Capital Power. The measurement categories include corporate measures and measures specific to certain groups within the Company. The corporate measures are company-wide and include funds from operations and safety. 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.

Operational excellence

Performance measure	2015 target	2015 actual results
Plant availability average [1]	94% or greater	95%
Capital expenditures for plant maintenance, Genesee mine extension and other (sustaining capital expenditures)	$65 million	$62 million
Plant operating and maintenance expenses	$180 million to $200 million	$192 million

1 All plants excluding acquired Sundance PPA.

In 2015, the Company's plant availability averaged 95% which reflected the second quarter planned outages at Genesee 1 and Joffre, the third quarter planned outage at Keephills 3, and unplanned outages for Shepard and Clover Bar Energy Centre Unit 2 in the second and third quarters, respectively.

Sustaining capital expenditures were less than target primarily due to the deferral of various projects into future periods.

The plant operating and maintenance expenses target includes other raw materials and operating charges, staff costs and employee benefits expense and other administrative expense for the Company's plants. The actual results for 2015 were consistent with the target range.

Disciplined growth

Performance measure	2015 target	Status as at December 31, 2015
K2 Wind	Complete construction with commercial operation date in mid-2015	Commercial operation commenced May 2015. Capital Power's share of final construction costs was $297 million, compared with the forecasted amount of $310 million.
Genesee 4 and 5	Transition from development to construction	In 2015, limited construction activities took place, but full notice to proceed was deferred. Full notice to proceed is contingent on clarification regarding the Alberta Climate Leadership Plan (CLP), including continuation of the current Alberta electricity market structure (see Significant Events), and appropriate price signals from the energy only market. It is expected that the current Alberta electricity market structure will not be compromised by the CLP.

See Outlook and Targets for 2016 for discussion of updated timing of completion of the Genesee 4 and 5 project.

Financial stability and strength

Performance measure	2015 target	2015 actual results
Funds from operations [1]	$365 million to $415 million	$400 million

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

Actual funds from operations for the year ended December 31, 2015 was in the target range.

OUTLOOK AND TARGETS FOR 2016

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

At its Investor Day held in December 2015, the Company provided financial guidance for 2016 funds from operations in the range of $380 million to $430 million. This was based on a price of $47 per MWh for 2016 for the Alberta baseload assets which are 100% hedged. The 2016 Alberta forward power price average of $37 per MWh, which is materially lower than the hedged price, is due to a combination of events including lower forward natural gas prices for 2016 and continued expected lower economic growth in Alberta and its expected impact on Alberta power demand growth. Lower expected growth in the Alberta economy is largely the result of the continuation of depressed global oil prices.

Despite the expected weaker economic environment, the Company expects an increased level of contracted cash flow in 2016 compared with 2015, primarily due to the first full year of operations at Shepard and K2 Wind and the addition of Beaufort Solar.

A priority for the Company in 2016 will be to work with the Alberta government to receive fair compensation for the proposed accelerated closure of its coal facilities in connection with the CLP (see Significant Events). The Company will also work diligently with regulators and other generators in the province to implement the Carbon Competitiveness Regulation (CCR) and 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. At that time Capital Power will further clarify if and when it will continue its construction of the Genesee 4 and 5 project and the planned construction and commercial operation date.

In 2016, Capital Power's availability target of 94% reflects major scheduled maintenance outages for Genesee 2, Genesee 3, Clover Bar Energy Centre, Joffre, and Shepard compared with the 2015 major scheduled maintenance outages for Genesee 1 and Keephills 3.

The Alberta portfolio position and contracted prices for 2015 (as at the beginning of the year) compared with 2016, 2017 and 2018 (all as at December 31, 2015) were:

Alberta commercial portfolio positions and power prices	**2015**	**2016**	**2017**	**2018**
Percentage of baseload generation sold forward [1]	97%	100%	38%	9%
Contracted price on net forward sales [2]	Mid-$50 per MWh	High-$40 per MWh	Low-$50 per MWh	Mid-$60 per MWh

1 Based on the Alberta baseload plants and the acquired Sundance PPA plus a portion of Joffre and the uncontracted portion of Shepard baseload.

2 The forecast average contracted prices may differ significantly from the future average realized prices as the hedged and unhedged positions have a varying mix of differently priced blocks of power.

The 2016 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. However, they do not include the effects of potential future acquisitions or development activities, or potential market and operational impacts relating to unplanned 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 to 2018. Each annual increase is subject to approval by the Board of Directors of Capital Power at the time of the increase.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding. It is expected that no additional common share equity will be required in 2016.

Performance measure targets for 2016

Performance measure	2016 target
Alberta Climate Leadership Plan – compensation	Ensure fair compensation will be received for the proposed accelerated closure of the Company's coal facilities.
Operational excellence	
Plant availability average	94% or greater
Sustaining capital expenditures	$65 million
Plant operating and maintenance expenses	$200 million to $220 million
Disciplined growth	
Genesee 4 and 5	Update construction timing based on clarification regarding the CLP and price signals from the energy only market.
New development	Execute a PPA for a new development.
Financial stability and strength	
Funds from operations [1]	$380 million to $430 million

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

NON-GAAP FINANCIAL MEASURES

The Company uses (i) earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, income from joint venture, and gains 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, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective.

Adjusted EBITDA

Capital Power uses adjusted EBITDA to measure the operating performance of 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 on disposals are excluded from the adjusted EBITDA measure.

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

(unaudited, $ millions)	Year ended December 31		Three months ended							
	2015	**2014**	**Dec 2015**	**Sep 2015**	**Jun 2015**	**Mar 2015**	**Dec 2014**	**Sep 2014**	**Jun 2014**	**Mar 2014**
Revenues	1,251	1,228	341	469	83	358	432	248	240	308
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(790)	(805)	(220)	(321)	(38)	(211)	(291)	(157)	(162)	(195)
Adjusted EBITDA	**461**	**423**	**121**	**148**	**45**	**147**	**141**	**91**	**78**	**113**
Depreciation and amortization	(215)	(189)	(56)	(53)	(55)	(51)	(49)	(47)	(47)	(46)
Foreign exchange (loss) gain	(15)	(10)	-	(8)	1	(8)	(4)	(5)	3	(4)
Finance expense	(94)	(55)	(27)	(25)	(24)	(18)	(16)	(15)	(11)	(13)
Income from joint venture	15	-	10	4	1	-	-	-	-	-
Income tax expense	(66)	(119)	(14)	(16)	(16)	(20)	(24)	(81)	(2)	(12)
Net income (loss)	**86**	**50**	**34**	**50**	**(48)**	**50**	**48**	**(57)**	**21**	**38**
Net income (loss) attributable to:										
Non-controlling interests	(4)	4	(1)	1	(14)	10	9	(12)	1	6
Shareholders of the Company	90	46	35	49	(34)	40	39	(45)	20	32
Net income (loss)	**86**	**50**	**34**	**50**	**(48)**	**50**	**48**	**(57)**	**21**	**38**

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. 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. As part of its collateral requirements, the exchange counterparty updates its bank margin accounts daily, by recording fair value changes on unsettled derivative financial instruments outstanding with its customers, including the Company. Consistent with the exchange counterparty, such changes are recorded as cash transactions on the Company's Consolidated Statements of Financial Position and net cash flows from operating activities. However, the underlying derivative transactions have not settled. Accordingly, the Company removes the effect of such fair value changes in its determination of funds from operations. 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)	Year ended December 31		Three months ended December 31	
	2015	**2014**	**2015**	**2014**
Net cash flows from operating activities per Consolidated Statements of Cash Flows	**419**	**391**	**114**	**107**
Add (deduct) items included in calculation of net cash flows from operating activities per Consolidated Statements of Cash Flows:				
Interest paid	80	45	28	16
Change in fair value of derivatives reflected as cash settlement	(8)	(17)	(3)	(17)
Realized gains on the settlement of interest rate derivatives	(3)	(2)	(2)	(1)
Miscellaneous financing charges paid [1]	5	5	2	-
Income taxes paid (recovered)	1	(10)	-	(3)
Change in non-cash operating working capital	(11)	(1)	8	9
	64	20	33	4
Finance expense [2]	(82)	(48)	(22)	(9)
Current income tax expense	(10)	(11)	(1)	(4)
Decrease in current income tax expense due to Part VI.1 tax	9	10	1	4
Funds from operations	**400**	**362**	**125**	**102**

[1] Included in other items of non-cash adjustments to reconcile net income to net cash flows from operating activities.

[2] Excludes unrealized changes on interest rate derivative contracts and amortization and accretion charges.

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 used in the calculation of earnings 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)	**Year ended December 31**		**Three months ended**							
	2015	**2014**	**Dec 2015**	**Sep 2015**	**Jun 2015**	**Mar 2015**	**Dec 2014**	**Sep 2014**	**Jun 2014**	**Mar 2014**
Basic earnings (loss) per share ($)	**0.70**	**0.28**	**0.29**	**0.44**	**(0.39)**	**0.41**	**0.40**	**(0.62)**	**0.17**	**0.33**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income	**90**	**46**	**35**	**49**	**(34)**	**40**	**39**	**(45)**	**20**	**32**
Preferred share dividends	(23)	(23)	(6)	(5)	(6)	(6)	(6)	(6)	(6)	(5)
Earnings (loss) attributable to common shareholders	67	23	29	44	(40)	34	33	(51)	14	27
Income tax expense related to increase in deferred tax liabilities caused by change in Alberta statutory corporate income tax rate	19	-	-	-	19	-	-	-	-	-
Unrealized foreign exchange loss (gain) on revaluation of U.S. dollar denominated debt	15	9	1	6	(2)	10	4	5	(3)	3
Unrealized changes in fair value of derivatives	8	(21)	11	(19)	33	(17)	(21)	(3)	8	(5)
Restructuring charges	2	-	-	2	-	-	-	-	-	-
Recognition of tax liability on foreign domiciled investment	1	-	-	-	1	-	-	-	-	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	(1)	1	-	-	(1)	-	1	-	-	-
Write-down of U.S. deferred tax assets	-	59	-	-	-	-	-	59	-	-
Amount received upon amendment of the Genesee Coal Mine Agreements	-	(14)	-	-	-	-	-	-	(14)	-
Genesee flood damage repair costs	-	2	-	-	-	-	-	-	1	1
Normalized earnings attributable to common shareholders	**111**	**59**	**41**	**33**	**10**	**27**	**17**	**10**	**6**	**26**
Weighted average number of common shares outstanding (millions)	96.4	82.3	98.7	100.9	102.1	83.7	83.3	82.8	81.9	81.2
Normalized earnings per share ($)	**1.15**	**0.72**	**0.42**	**0.33**	**0.10**	**0.32**	**0.20**	**0.12**	**0.07**	**0.32**

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

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Year ended December 31		
	2015	2014	2013
Revenues	1,251	1,228	1,393
Adjusted EBITDA [1]	461	423	509
Net income	86	50	228
Net income attributable to shareholders of the Company	90	46	175
Normalized earnings attributable to common shareholders [1]	111	59	127
Basic earnings per share ($)	0.70	0.28	2.13
Diluted earnings per share ($) [2]	0.70	0.28	2.08
Normalized earnings per share ($) [1]	1.15	0.72	1.74
Funds from operations [1,3]	400	362	426
Purchase of property, plant and equipment and other assets	140	220	943
Dividends per common share, declared ($)	1.410	1.310	1.260
Dividends per Series 1 preferred share, declared ($)	1.150	1.150	1.150
Dividends per Series 3 preferred share, declared ($)	1.150	1.150	1.178
Dividends per Series 5 preferred share, declared ($)	1.125	1.125	0.895

	As at December 31		
	2015	2014	2013
Loans and borrowings including current portion	1,615	1,586	1,527
Total assets	5,393	5,420	5,219

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 per share was calculated after giving effect to outstanding share purchase options and the exchange of common limited partnership units of CPLP held by EPCOR for common shares of Capital Power on a one-for-one basis. See Significant Events.

3 The reported funds from operations measure was changed consistent with the reclassification of Part VI.1 tax from operating activities to financing activities in the Company's Consolidated Statement of Cash Flows. All comparative funds from operations amounts for 2014 and 2013 were revised.

Normalized earnings attributable to common shareholders and normalized earnings per share

Normalized earnings attributable to common shareholders and normalized earnings per share were higher for 2015 compared with 2014. See Consolidated Net Income and Results of Operations for discussion of the key drivers of the increases for the year. The number of common shares outstanding increased as a result of the common shares issued to EPCOR following the exchange transactions (see Significant Events).

Funds from operations

Funds from operations for 2015 increased in comparison to funds from operations for 2014 due to higher adjusted EBITDA. See Results by Plant Category and Other for discussion of the key drivers.

SIGNIFICANT EVENTS

Medium-term note exchange

On December 17, 2015, CPLP noteholders of issued and outstanding 4.85% medium-term notes due February 21, 2019 ("Series 3") and 5.276% medium-term notes due November 16, 2020 ("Series 1") (collectively, the "CPLP Notes") voted to exchange the CPLP Notes for an equal principal amount of newly issued medium-term notes of Capital Power (Note Exchange Transaction). The newly issued notes have terms and conditions that are the same as those attached to the CPLP Notes. The Note Exchange Transaction was successfully completed on December 18, 2015 and is expected to simplify the organizational structure, reduce reporting obligations, and result in efficiencies for CPLP while providing noteholders with better liquidity over time and structural enhancement. Effective January 1, 2016, as a result of the Note Exchange Transaction, CPLP is no longer a reporting issuer.

Preferred Shares (Series 1) conversion privilege and dividend rate notice

On December 1, 2015, Capital Power notified registered shareholders of the Company's Cumulative 5-Year Rate Reset Preference Shares, Series 1 (Series 1 Shares) of the conversion privilege and dividend rate notice. Series 1 shareholders had the right to elect to convert any or all of their Series 1 Shares into an equal number of Cumulative Floating Rate Preference Shares, Series 2 (Series 2 Shares). Following the conversion deadline on December 16, 2015, approximately 930,800 Series 1 Shares were tendered for conversion, which was less than the one million shares required for conversion into Series 2 Shares. Accordingly, there were no Series 2 Shares issued as at December 31, 2015. Effective December 31, 2015, the Annual Fixed Dividend Rate for the Series 1 Shares for the next five year period was reset from 4.60% to 3.06%.

Beaufort Solar begins commercial operation

On December 22, 2015, Capital Power's 15 MW Beaufort Solar facility was commissioned and commenced operating under a 15 year power purchase agreement with Duke Energy Progress LLC. The Company constructed the facility and then entered into a sale and leaseback agreement with an A-rated U.S. financial institution for proceeds of $46 million (US$34 million) and a lease term of 10 years with an option for extension at the end of the lease term. The lease is classified as a finance lease for accounting purposes. As a result, the gain on the sale of the facility of $5 million (US$4 million) was recognized as deferred revenue on the Company's Consolidated Statements of Financial Position and will be amortized over the term of the lease.

Dividend increase

On July 27, 2015, the Company announced that its Board of Directors approved a 7.4% increase in the annual dividend for holders of its common shares, from $1.36 per common share to $1.46 per common share. This increased common share dividend commenced with the third quarter 2015 quarterly dividend payment paid on October 30, 2015 to shareholders of record at the close of business on September 30, 2015.

Changes to Alberta's emissions regulations and the announcement of the Alberta Climate Leadership Plan

On June 25, 2015, the Alberta government announced changes to Alberta's regulations governing carbon emissions and a comprehensive review of Alberta's climate change policy. The changes to the Specified Gas Emitters Regulation (SGER) will increase the required reduction in emissions intensity from 12% to 15% in 2016 and 20% in 2017, and increase the cost of contributions to the Climate Change and Emissions Management Fund from $15 per tonne of greenhouse gases to $20 per tonne in 2016 and $30 per tonne in 2017.

On August 14, 2015, a five member panel, appointed by the Alberta Minister of Environment and Parks, was announced with a mandate to provide recommendations to the Alberta government on how to address climate change in Alberta. Capital Power actively participated in the consultation process that led to the Alberta Climate Leadership Plan (CLP) that was announced on November 22, 2015.

The CLP provides guidance in three primary areas that affect the Company: changes to the compliance requirements for coal emissions, procurement of target renewable generation, and the accelerated retirement of Alberta coal-fired generation. The CLP recommends that the existing SGER be replaced in 2018 with the CCR. Under the CCR, electricity generators will pay $30 per tonne of greenhouse gas emissions above an electricity sector performance standard, which has yet to be determined. Coal emissions from coal-fired generating plants will be zero by 2030, subject to release of final CLP legislation and ensuring Alberta electric system reliability. It is expected that two-thirds of the phased out coal-fired generation will be replaced by renewable generation. The Company's Genesee 1 and Genesee 2 units and its 50% interests in the Genesee 3 and Keephills 3 units are all affected by this recommendation of the CLP. The Alberta government has committed to treat workers, communities and affected companies fairly, and avoid stranding capital. The CLP recommends that Renewable Energy Credits (RECs) be offered through a competitive process to the developers of renewables projects. The CLP maintains Alberta's deregulated market structure with new generation outside the renewable procurement process to continue to be built based on price signals from the energy only market.

Capital Power expects that the increase in the Company's compliance costs under the CCR will be mitigated by higher wholesale power prices from owner's passing through the compliance costs and the use of its inventory of low-cost carbon offset credits. The projected incremental impact of the CCR, between 2018 and 2020, is an average annual increase of approximately $20 million in adjusted EBITDA. From 2021 to 2029, the projected annual impact to adjusted EBITDA is a decrease of approximately $100 million, due to increased compliance costs of the CCR due to the depletion of the Company's carbon offset inventory and the expiry of the Genesee 1 and Genesee 2 PPAs. Under the terms of those PPA's, any carbon offset costs as a result of a change in legislation (like the CCR) are and will be borne by the PPA holder, the Balancing Pool, until 2020. Thereafter, the full CCR cost for Genesee 1 and Genesee 2 will be borne by Capital Power. Although unrelated to the CCR, the decrease in adjusted EBITDA is expected to be more than offset by the sale of electricity from Genesee 1 and Genesee 2 into the Alberta wholesale market at prices which are expected to exceed the contracted price under the PPA. The contracted prices under the PPA are projected to be approximately $37 per MWh in 2020. These projections do not take into account the compensation to be received from the Alberta government for the accelerated closure of Alberta's coal-fired power plants and assume no actions by Capital Power to further reduce greenhouse gas emissions.

There are numerous uncertainties associated with the CLP. Most significantly, it represents a proposed framework that has not been substantively enacted in legislation and therefore the final legal form and substance of the CLP is unknown. The Alberta government has indicated that an independent facilitator and the Alberta Electric System Operator (AESO) will work with owners of coal-fired power generation to address compensation and develop a transition plan. The Company will work closely with the government, the facilitator and the AESO, and strive to ensure successful implementation of government policies for the electricity sector and our investors. While the Company will employ its best efforts, there can be no assurance that the legislated process to replace coal-fired generation with renewables will not disrupt the effective functioning of Alberta merchant power market and there can be no assurance that the Company will be appropriately and sufficiently compensated for the potential early retirement of its coal assets.

K2 Wind begins commercial operation

On May 29, 2015, Capital Power, Samsung Renewable Energy Inc. and Pattern Energy Group LP announced that K2 Wind was fully operational and capable of generating 270 MW of electricity for the province of Ontario and would operate under a 20-year power purchase agreement with the Independent Electricity System Operator (IESO). Capital Power owns 90 MW or 33.3% of the capacity of this facility. Capital Power's share of final construction costs was $297 million, including both debt and equity financed components.

Secondary offering of Capital Power shares by EPCOR

On April 2, 2015, EPCOR exchanged all of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9.450 million of such common shares to the public pursuant to a secondary offering at $23.85 per common share. Capital Power did not receive any of the proceeds from EPCOR's sale of common shares. After giving effect to the exchange and the secondary offering, EPCOR owns approximately 9.1% of the common shares of Capital Power and no special voting shares of Capital Power or limited partnership units of CPLP. EPCOR has advised that it plans to eventually sell all or a substantial portion of its remaining interest in Capital Power, subject to market conditions, based on its requirements for capital and other circumstances that may arise in the future. In connection with the offering, the Registration Rights Agreement between Capital Power and EPCOR was terminated. Thus, the Company will no longer be obligated to assist EPCOR in making a secondary offering and any future sales of common shares by EPCOR will be completed by other means. As a result of EPCOR ceasing to hold special voting shares and EPCOR's ownership interest in Capital Power decreasing to below 10%, EPCOR no longer has the right, separately as a holder of special voting shares, to nominate and appoint any directors to Capital Power's Board of Directors.

This exchange and secondary offering by EPCOR and the medium-term note exchange discussed above will allow the Company to simplify the organization structure and reporting, and reduce costs associated with CPLP, including audit, legal, board, management and filing expenses.

Approval of normal course issuer bid and suspension of Dividend Re-investment Plan

On March 25, 2015, Capital Power's normal course issuer bid (NCIB) to purchase and cancel up to 5 million of its outstanding common shares during the one-year period from April 7, 2015 to April 6, 2016 was approved by the Toronto Stock Exchange (TSX). On November 27, 2015 the TSX approved an amendment to Capital Power's NCIB to purchase and cancel up to an additional 3,369,838 shares. Up to December 31, 2015, the Company purchased and cancelled approximately 6 million common shares totalling $121 million. Effective with the June 30, 2015 dividend, Capital Power suspended its Dividend Re-investment Plan (DRIP) for its common shares until further notice. Shareholders participating in the DRIP began receiving cash dividends as of the July 31, 2015 payment date.

Shepard begins commercial operation

On March 11, 2015, Capital Power and ENMAX announced that Shepard was fully operational and capable of generating over 800 MW of electricity to the Alberta grid. Capital Power became a 50% owner of this natural gas facility in 2012 and its final construction costs are expected to be $848 million, which includes a performance bonus paid to the turbine manufacturer. The commercial arrangements with ENMAX include a 20-year tolling agreement where 75% of the Company's owned capacity is contracted from 2015 to 2017 and 50% thereafter to 2035.

Executive appointments

Capital Power and the Board of Directors announced the appointments of Bryan DeNeve to the executive position of Senior Vice President, Finance and Chief Financial Officer and Stuart Lee to the executive position of Senior Vice President Corporate Development and Commercial Services effective May 1, 2015. Mr. DeNeve and Mr. Lee formerly held the positions of Senior Vice President Corporate Development and Commercial Services and Senior Vice President, Finance and Chief Financial Officer, respectively.

The Company announced the appointment of Mark Zimmerman to the position of Senior Vice President, Corporate Development and Commercial Services effective November 2, 2015, to replace Mr. Lee who resigned from Capital Power effective August 31, 2015.

PLANTS AND PORTFOLIO OPTIMIZATION OPERATIONS

			Capacity (MW)			
Plant category and plant	Type of generating plant	Year commissioned	Plant	Capital Power interest	Revenues based on	Contract expiry
Alberta commercial plants and acquired Sundance PPA						
Genesee 3	Supercritical coal-fired	2005	516	258	Merchant	-
Keephills 3	Supercritical coal-fired	2011	516	258	Merchant	-
Clover Bar Energy Centre 1, 2 and 3	Natural gas-fired simple cycle	2008 (Unit 1) 2009 (Units 2 and 3)	243	243	Merchant	-
Joffre	Natural gas-fired combined cycle cogeneration	2000	480	192	Merchant (mid-merit)	-
Shepard	Natural gas-fired combined cycle	2015	800	400	Merchant with tolling agreement for 50% of owned capacity plus additional 25% contracted for 2015 to 2017	2035 (tolling agreement)
Halkirk	Wind turbine	2012	150	150	Merchant with RECs sold under fixed price agreement	2032 (RECs)
Clover Bar Landfill Gas	Landfill gas-fired	2005	5	5	Merchant with emission credits purchased by Capital Power from the City of Edmonton	-
Acquired Sundance PPA	Coal-fired steam turbine	1978 (Unit 5) 1980 (Unit 6)	710	371	Merchant (plant capacity and output purchased under Alberta PPA)	2020
Alberta contracted plants						
Genesee 1	Coal-fired steam turbine	1994	430	430	Capacity and output sold under Alberta PPA to Alberta Balancing Pool	2020
Genesee 2	Coal-fired steam turbine	1989	430	430	Capacity and output sold under Alberta PPA to Alberta Balancing Pool	2020
Ontario and British Columbia contracted plants						
Island Generation	Natural gas-fired combined cycle	2002	275	275	PPA with B.C. Hydro	2022
K2 Wind	Wind turbine	2015	270	90	PPA with IESO	2035
Kingsbridge 1	Wind turbine	2001 and 2006	40	40	Energy supply contracts with IESO	2026
Port Dover and Nanticoke	Wind turbine	2013	105	105	Energy supply contract with IESO	2033
Quality Wind	Wind turbine	2012	142	142	Energy purchase agreement with B.C. Hydro	2037
U.S. contracted plants						
Roxboro, North Carolina	Solid fuels (wood residuals, tire-derived and coal)	1987	46	46	PPA with Duke Energy Progress Inc.	2021
Southport, North Carolina	Solid fuels (wood residuals, tire-derived and coal)	1987	88	88	PPA with Duke Energy Progress Inc.	2021
Beaufort Solar, North Carolina	Solar	2015	15	15	PPA with Duke Energy Progress, LLC	2030
Macho Springs, New Mexico	Wind turbine	2011	50	50	PPA with Tucson Electric Power	2031

Plant category and plant	Type of generating plant	Year commissioned	Capacity (MW) Plant	Capacity (MW) Capital Power interest	Revenues based on	Contract expiry
Under construction or in advanced development						
Genesee 4 and 5	Natural gas-fired combined cycle	As early as 2020 [1]	1,060	530	Merchant with approximately 250 MW contracted to ENMAX for initial term of 8 years	To be determined

1 Contingent on clarification of fair compensation the Company will receive for the projected accelerated closure of coal-fired generating units in Alberta, the implementation of the CLP having no adverse impact on the Alberta electricity market design, and upon price signals from the energy only market.

Portfolio optimization

Capital Power's commodity portfolio is comprised of generation assets, customer positions and trading positions. All commodity risk management and optimization activities are centrally managed by Capital Power's commodity portfolio management group. Portfolio optimization includes activities undertaken to manage Capital Power's exposure to commodity risk and enhance earnings. Overall commodity exposure within the portfolio is managed within limits established under Capital Power's risk management policies.

Capital Power manages its output from its commercial plants, contracted plants with residual commodity exposure and acquired PPAs on a portfolio basis. Capital Power sells and/or buys physical and/or financial forward contracts that are non-unit specific, to reduce exposure to plant specific availabilities. Capital Power also takes positions in the environmental commodity markets outside of Alberta to develop capability to support Capital Power's growth strategy and to generate trading profits.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for 2015 compared with 2014 are presented below followed by further discussion of these items.

(unaudited, $ millions)		
Consolidated net income for the year ended December 31, 2014		**50**
Increase (decrease) in adjusted EBITDA:		
Alberta commercial plants and portfolio optimization	43	
Alberta contracted plants	23	
Ontario and British Columbia contracted plants	5	
U.S. contracted plants	20	
Corporate	(17)	
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits	(36)	38
Increase in depreciation and amortization expense		(26)
Increase in foreign exchange loss		(5)
Increase in finance expense		(39)
Income from joint venture		15
Decrease in income before tax		(17)
Decrease in income tax expense		53
Increase in net income		**36**
Consolidated net income for the year ended December 31, 2015		**86**

Results by Plant Category and Other

	Year ended December 31							
	2015	2014	2015	2014	2015	2014	2015	2014
	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 acquired Sundance PPA	14,567	12,376	95	95	780	753		
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	1,982	1,746	100	91	63	86		
Keephills 3	1,640	1,674	90	98	51	80		
Clover Bar Energy Centre 1, 2 and 3	248	296	94	95	26	44		
Joffre	308	324	97	93	29	39		
Shepard [4]	1,462	N/A	89	N/A	64	N/A		
Halkirk	460	462	97	96	34	36		
Clover Bar Landfill Gas	8	14	89	78	-	-		
Alberta commercial plants – owned	6,108	4,516	94	94	267	285		
Acquired Sundance PPA	2,661	2,763	88	84	81	112		
Portfolio optimization	N/A	N/A	N/A	N/A	434	215		
	8,769	7,279	92	90	782	612	254	211
Alberta contracted plants								
Genesee 1	3,130	3,160	92	95				
Genesee 2	3,378	3,075	99	91				
	6,508	6,235	96	93	275	266	184	161
Ontario and British Columbia contracted plants								
Island Generation	79	130	100	100	38	38		
K2 Wind [5]	167	N/A	98	N/A	N/A	N/A		
Kingsbridge 1	101	105	96	95	6	7		
Port Dover and Nanticoke	299	301	97	97	36	37		
Quality Wind	408	349	97	96	44	37		
	1,054	885	98	98	124	119	97	92
U.S. contracted plants								
Roxboro, North Carolina	282	244	95	97	32	24		
Southport, North Carolina	506	491	91	91	70	59		
Beaufort Solar, North Carolina [6]	-	N/A	100	N/A	-	N/A		
Macho Springs, New Mexico [7]	109	5	98	99	12	-		
	897	740	94	93	114	83	27	7
Corporate [8]					8	27	(100)	(84)
Unrealized changes in fair value of commodity derivatives and emission credits					(52)	121	(1)	36
Consolidated revenues and adjusted EBITDA					**1,251**	**1,228**	**461**	**423**

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 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 Consolidated Statements of Income. The plant was commissioned on May 29, 2015 and the

equivalent of Capital Power's share of the plant's revenue and adjusted EBITDA was $25 million and $21 million, respectively for 2015.

6 Beaufort Solar was commissioned on December 22, 2015.

7 Macho Springs was acquired in December 2014.

8 Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

		Year ended December 31	
Alberta	**Unit**	**2015**	**2014**
Hedged position [1]	Percentage sold forward at beginning of year (%)	97	100
Spot power price average	$ per MWh	33	49
Realized power price [2]	$ per MWh	55	58
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	2.60	4.49

1 Hedged position is for the Alberta baseload plants and acquired Sundance PPA plus a portion of Joffre and the uncontracted portion of Shepard baseload.

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, acquired Sundance PPA and portfolio optimization

Generation increased 1,490 GWh for 2015 compared with 2014 primarily due to the addition of Shepard, higher production at Genesee 3 as a result of no planned outage in 2015 compared with a planned outage in 2014 and a shorter planned outage at the acquired Sundance PPA units in 2015 compared with 2014. These increases were partly offset by the planned outage at Keephills 3 in 2015, more unplanned outages at the acquired Sundance PPA units in 2015 compared with 2014 and, to a lesser extent, the unplanned outage at Clover Bar Energy Centre Unit 2 during the third quarter of 2015.

The lower average spot price for 2015 compared with 2014 reflected minimal market volatility due to generation from Shepard, fewer unplanned baseload plant outages, and lower market demand.

Revenues and adjusted EBITDA were higher in 2015 compared with 2014 primarily due to higher generation as noted above, despite the lower average spot price in 2015. The Company realized higher power prices by selling forward its commercial production, a portion of which was secured in June 2015 when forward rates increased temporarily. Increased adjusted EBITDA for 2015 compared with 2014 was partially offset by the reallocation of coal costs between Genesee 1 and 2 and Genesee 3 in 2014. In 2014, the Company also recovered $8 million on a claim with a supplier relating to the 2008 Genesee 3 turbine failure.

Alberta contracted plants

Production and availability for Genesee 1 decreased in 2015 compared with 2014 primarily due to the planned outage in 2015, partly offset by fewer and shorter unplanned outages in 2015, compared with 2014. Production and availability for Genesee 2 increased in 2015 compared with 2014 primarily due to the planned outage in 2014 and fewer and shorter unplanned outages in 2015, compared with 2014. Revenues and adjusted EBITDA for the Alberta contracted plants were higher in 2015 compared with 2014 primarily due to increased availability, higher PPA indices, lower coal costs, and flood damage repairs recognized in 2014, partly offset by the impact of lower power prices in 2015.

Ontario and British Columbia contracted plants

Generation increased in 2015 compared with 2014 due to the addition of K2 Wind in the second quarter of 2015 and increased wind generation at Quality Wind.

Revenues and adjusted EBITDA increased in 2015 compared with 2014 primarily due to increased wind generation at Quality Wind. While Island Generation's dispatch decreased in 2015 compared with 2014, the impact on revenues and adjusted EBITDA was minimal because, under the terms of the Island Generation agreement, revenues are based on deemed generation which is determined based on the plant's availability. Deemed generation for 2015 was consistent with 2014 and Island Generation was not dispatched as often during 2015. Revenues and adjusted EBITDA for 2015 do not include the operational results of K2 Wind which is accounted for under the equity method.

U.S. contracted plants

Generation increased in 2015 compared with 2014 due to a full year of operations at Macho Springs and increased off-peak generation at Roxboro and Southport. These factors, combined with an increase in contracted prices for the sale of renewable energy credits, contributed to higher revenues and adjusted EBITDA in 2015 compared with 2014.

The commencement of operations at Beaufort Solar on December 22, 2015 did not materially impact 2015 results.

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.

In keeping with Capital Power's ongoing objectives to realize efficiencies, the Company incurred $3 million of restructuring charges, primarily a reduction of headcount, during the third quarter of 2015. This additional charge was more than offset by reduced performance incentive expenses. The Company also recognized $20 million of revenues in the second quarter of 2014 arising from the amendment of the Genesee Coal Mine Agreements on the acquisition of Prairie Mines & Minerals Royalty Ltd.'s 50% interest in the Genesee Coal Mine by Westmoreland Coal Company. There were no comparable revenues in 2015.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Year ended December 31			
Unrealized changes in fair value of commodity derivatives and emission credits	**2015**	**2014**	**2015**	**2014**
	Revenues		**Adjusted EBITDA**	
Unrealized (losses) gains on Alberta energy derivatives	(52)	112	(1)	26
Unrealized gains on emission derivatives	-	8	-	8
Other	-	1	-	2
	(52)	**121**	**(1)**	**36**

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 or Corporate category.

Unrealized changes in the fair value of Alberta energy derivatives for December 31, 2015 were immaterial compared with unrealized net gains of $26 million for 2014. The unrealized net gains for 2014 primarily reflected the impact of decreasing Alberta forward power prices combined with the portfolio's net forward sales contracts.

Unrealized changes in the fair value of emission derivatives were immaterial in 2015 compared with unrealized net gains of $8 million in 2014. The unrealized net gains for 2014 primarily reflected net forward sales contracts priced at values in excess of forward prices.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $ millions)	Year ended December 31	
	2015	2014
Interest on borrowings less capitalized interest	(80)	(45)
Realized gain on settlement of interest rate derivatives	3	2
Other finance expense – sundry interest and guarantee and other fees	(5)	(5)
	(82)	(48)
Unrealized loss representing changes in the fair value of interest rate derivatives	(5)	-
Other finance expense – amortization and accretion charges	(6)	(5)
Other finance expense – finance charges incurred on early debt extinguishment	(1)	(2)
Total finance expense	(94)	(55)
Depreciation and amortization	(215)	(189)
Foreign exchange loss	(15)	(10)
Income tax expense	(66)	(119)
Net loss (income) attributable to non-controlling interests	4	(4)

Finance expense

Higher finance expense for 2015 compared with 2014 was primarily due to decreased capitalized interest as Shepard was completed in March 2015 and additional debt incurred as a result of the acquisition of Macho Springs in December 2014.

Depreciation and amortization

Depreciation and amortization for 2015 increased $26 million compared with the prior year primarily due to additional depreciation recognized for Macho Springs which was acquired in December 2014 and for Shepard which commenced commercial operation in March 2015.

Foreign exchange loss

As at December 31, 2015, the Company had outstanding U.S. dollar denominated debt payable totalling US$295 million. Approximately US$195 million is hedged for accounting purposes using foreign currency swaps. Foreign exchange loss consisted of the loss incurred on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes. For 2015, the exchange rate of the Canadian dollar relative to the U.S. dollar decreased resulting in an unrealized loss of $15 million.

Income tax expense

Income tax expense decreased by $53 million for 2015 compared with 2014 primarily due to a $73 million write-down of U.S. income tax loss carryforwards in the third quarter of 2014. This decrease was partially offset by an increase in income tax expense of $19 million in the second quarter of 2015 due to the increase in the Alberta statutory corporate income tax rate which increased deferred tax liabilities on the Consolidated Statements of Financial Position.

Non-controlling interests

For the period from January 1, 2015 to April 2, 2015, 18% of CPLP's net income was attributable to EPCOR (2014 - 19%) which was reported as net income attributable to non-controlling interests by the Company. Effective April 2, 2015, EPCOR disposed of all its interest in CPLP (see Significant Events). Net income attributable to non-controlling interests also included the Genesee Coal Mine Assets (Coal Mine) partner's share of the consolidated net income of the Coal Mine. Subsequent to April 2, 2015, non-controlling interests for future periods will consist only of the Coal Mine partner's share of consolidated net income of the Coal Mine.

COMPREHENSIVE INCOME

(unaudited, $ millions)	Year ended December 31	
	2015	2014
Net income	86	50
Other comprehensive income:		
Net unrealized gains on commodity derivatives designated as cash flow hedges	65	44
Net realized gains on commodity derivatives designated as cash flow hedges reclassified to revenues and/or energy purchases and fuel	(59)	(18)
Unrealized foreign exchange gains on the translation of foreign operations	34	16
Actuarial gains (losses) related to the company's defined benefit pension plan	4	(2)
	44	40
Comprehensive income	**130**	**90**

Other comprehensive income includes fair value adjustments on financial instruments held by the Company to hedge market risks and which meet the requirements of hedges for accounting purposes. To the extent that such hedges are ineffective, any related gains or losses are recognized in net income. Other unrealized fair value changes on derivatives designated as cash flow hedges and foreign currency translation gains or losses are subsequently recognized in net income when the hedged transactions are completed and the foreign operations are disposed of or otherwise terminated. The actuarial gains or losses are not subsequently recognized in net income.

FINANCIAL POSITION

The significant changes in the Consolidated Statements of Financial Position from December 31, 2014 to December 31, 2015 were as follows:

(unaudited, $ millions)	As at December 31		Increase	
	2015	2014	(decrease)	Primary reason for increase (decrease)
Net derivative financial instruments assets	167	113	54	Impact of decreased Alberta forward power prices on the fair value of forward sales contracts.
Finance lease receivables	689	708	(19)	Payments received.
Equity-accounted investment	10	22	(12)	Primarily distributions received.
Property, plant and equipment	3,679	3,701	(22)	Depreciation and amortization, partly offset by capital additions (most significantly, Shepard and Beaufort Solar).
Loans and borrowings (including current portion)	1,615	1,586	29	Increased bankers' acceptances outstanding and increased U.S. dollar denominated debt outstanding including the impact of foreign exchange, partly offset by repayment of loans and borrowings.
Finance lease obligation (including current portion)	22	-	22	Pursuant to the Beaufort Solar sale and leaseback agreement.
Provisions (including current portion)	232	220	12	Increased decommissioning provisions resulting from discount rate reductions.
Net deferred tax liabilities	358	228	130	Impact of increased Alberta statutory income tax rate and increased share ownership of CPLP.
Share capital	2,744	2,391	353	Shares issued to EPCOR and under the Dividend Re-Investment Plan, partly offset by common share purchases by Capital Power.
Retained earnings (deficit)	(70)	25	(95)	Net income offset by common and preferred share dividends.
Other reserves	74	35	39	Unrealized gains on cash flow hedges and foreign currency translation, partly offset by reclassification of gains to income.
Non-controlling interests	68	552	(484)	EPCOR's exchange of exchangeable common limited partnership units of CPLP for common shares of Capital Power.

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Year ended December 31		
Cash inflows (outflows)	**2015**	**2014**	**Increase (decrease)**
Operating activities	419	391	28
Investing activities	(136)	(230)	94
Financing activities	(280)	(191)	(89)

Operating activities

Cash flows from operating activities for 2015 increased compared with 2014 primarily due to the increase in overall plant adjusted EBITDA and higher contributions from operating working capital, partly offset by the receipt in 2014 of $20 million in revenues on the amendment of the Genesee Coal Mine Agreements.

Investing activities

Cash flows used in investing activities for 2015 were lower than those for 2014, primarily due to the completion of Shepard and K2 Wind earlier in the year. Included in purchase of property, plant and equipment and other assets is the construction of the Beaufort Solar facility of $38 million (US$30 million). This facility was sold to Wells Fargo pursuant to a sale and leaseback transaction for proceeds of $46 million (US$34 million).

Capital expenditures and investments

(unaudited, $ millions)	Pre-2014 Actual	Year ended December 31 2014 Actual	2015 Actual	2016 Estimated [1, 2]	Actual or Projected Total [2, 3]	Timing
Port Dover and Nanticoke [4]	276	11	1	-	288	Completed 4th quarter 2013
K2 Wind [5]	16	28	(6)	-	297	Commercial operation commenced May 2015
Shepard	684	127	36	1	848	Commercial operation commenced March 2015
Beaufort Solar	-	-	38	-	38	Commercial operation commenced December 2015
Genesee 4 & 5 [6]	-	2	7	24	700	Targeted completion as early as 2020 and 2021, respectively [7]
Subtotal growth projects		**168**	**76**			
Sustaining – plant maintenance excluding Genesee mine		54	51			
Sustaining – Genesee mine maintenance and lands [8]		8	6			
Sustaining – other		13	5			
Total capital expenditures [9]		**243**	**138**			
Emission credits held for compliance		16	11			
Capitalized interest		(39)	(9)			
Purchase of property, plant and equipment and other assets		**220**	**140**			

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

2 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.

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

4 Costs for the Port Dover and Nanticoke project completed in 2013 include certain costs that were incurred subsequent to the date of commercial operations such as site remediation, vendor optimization, project clean-up and close-out costs.

5 The actual expenditures for K2 Wind primarily consist of the Company's estimated equity contribution to the K2 Wind partnership. Capital Power's share of the K2 Wind partnership's capital expenditures is $297 million including both debt and equity financed components. In the fourth quarter of 2015, a partnership distribution of $8 million representing a return of capital previously invested was received.

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

7 Contingent on clarification of fair compensation the Company will receive for the projected accelerated closure of coal-fired generating units in Alberta, the implementation of the CLP having no adverse impact on the Alberta electricity market design, and upon price signals from the energy only market. The Company has extended the deadline to provide full notice to proceed to the turbine manufacturer for Genesee 4 & 5 by up to 90 days from the previous March 1, 2016 deadline.

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

9 Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the Consolidated Statements of Cash Flows as purchase of property, plant and equipment and other assets.

Financing activities

Under the Note Exchange Transaction, certain CPLP medium-term notes with a principal amount outstanding of $550 million were exchanged for identical Capital Power medium-term notes (see Significant Events). The Company's NCIB was approved by the TSX and the Company purchased its own common stock for total consideration of $121 million (See Significant Events). In keeping with the reduced capital project spending profile, the financing requirements for 2015 consisted primarily of normal course activities including scheduled debt repayments, interest payments and dividend payments. The Company financed the maturity of certain medium-term notes in the fourth quarter of 2015 with availability on its committed credit facilities.

The Company's credit facilities consisted of:

(unaudited, $ millions)		As at December 31, 2015			As at December 31, 2014		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
CPLP committed credit facility	2020	1,000			1,200		
Letters of credit outstanding			15			122	
Bankers' acceptances outstanding			212			-	
U.S. dollar bank loans outstanding			27			17	
		1,000	254	746	1,200	139	1,061
CPLP bilateral demand credit facilities	N/A	200					
Letters of credit outstanding			110	90	N/A	N/A	N/A
CPLP demand credit facility	N/A	20	-	20	20	-	20
Capital Power Corporation demand credit facility	N/A	5	-	5	5	-	5
		1,225	**364**	**861**	**1,225**	**139**	**1,086**

During the second quarter of 2015, the Company amended its credit facilities to reduce the committed credit facility from $1,200 million to $1,000 million. During the third quarter of 2015, the Company entered into $200 million of additional bilateral demand credit facilities specifically for the issuance of letters of credit at lower costs. As at December 31, 2015, the total credit facility utilization increased $225 million compared with the utilization as at December 31, 2014 primarily due to the maturity of approximately $226 million in medium-term notes in the fourth quarter of 2015. 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 committed 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). 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.

The loan and credit agreements require CPLP to meet certain financial covenants as described below:

Financial covenant	Required at the end of each fiscal quarter	Actual as at December 31, 2015
Senior debt to consolidated capitalization ratio [1]	Not more than 0.65 to 1.0	0.37
Consolidated EBITDA to consolidated interest expense [1, 2]	Not less than 2.5 to 1.0	3.5

1 As defined in the relevant agreements.

3 Only in the event that CPLP is assigned a rating of less than BBB- by S&P and less than BBB (low) by DBRS.

As a result of the Note Exchange Transaction (see Significant Events) and as part of the effort to simplify the organization structure and reporting requirements, amendments were made to the loan credit agreements such that effective January 2016, Capital Power will be required to meet the financial covenants referenced above in place of CPLP. The impact on the calculation of these covenants is not expected to be material. The Company will also be required to maintain the credit ratings referenced above, in place of CPLP.

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)	2016 Expected Cash Requirements
Repayment of debt payable to EPCOR	139
Capital expenditures excluding capitalized interest and emission credits held for compliance	65
Common share dividends [1]	145
Preferred share dividends	20

1 Includes 7% annual dividend growth, subject to approval by the Board of Directors of Capital Power.

Capital Power Corporation suspended its DRIP effective with the June 30, 2015 dividend. The participation rate in the DRIP was approximately 39% at the time of the suspension of the plan. Shareholders participating in the DRIP began receiving cash dividends as of the July 31, 2015 payment date.

The current portion of loans and borrowings on the December 31, 2015 Consolidated Statements of Financial Position included $325 million senior debt payable to EPCOR which was classified as current since the debt is callable and, therefore, all potentially repayable in 2016 (see Transactions with Related Parties). The callable amount includes a $130 million senior note which is otherwise contractually due in 2016.

The Company expects to fund the construction of Genesee 4 and 5 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 January 2017.

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 December 31, 2015, $125 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 December 31	
	2015	**2014**
Loans and borrowings	1,615	1,586
Finance lease obligation	22	-
Less cash and cash equivalents	80	71
Net debt	1,557	1,515
Share capital	2,744	2,391
Retained earnings and other reserves	4	60
Non-controlling interests	68	552
Total equity	2,816	3,003
Total capital	**4,373**	**4,518**

CONTRACTUAL OBLIGATIONS AND CONTINGENT LIABILITIES

(unaudited, $ millions)	Payments due by period						
	2016	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**
Loans and borrowings	154	22	184	259	546	460	1,625
Interest on loans and borrowings	51	43	39	33	28	57	251
Finance lease obligations	1	1	2	2	2	14	22
Capital – growth projects [1]	32	135	228	207	72	17	691
Acquired PPA obligations – fixed [2]	60	59	60	62	64	-	305
Acquired PPA obligations – variable [2]	40	37	59	79	82	-	297
Decommissioning provisions [3]	2	2	2	2	2	308	318
Energy purchase and transportation contracts [4]	105	85	84	89	28	433	824
Operating and maintenance contracts	21	19	22	20	24	196	302
Operating leases	8	8	8	8	8	65	105
Environmental credits	39	41	8	7	6	6	107
Commodity and other derivatives liabilities net of financial assets	26	5	-	-	-	-	31
Total	**539**	**457**	**696**	**768**	**862**	**1,556**	**4,878**

1 Capital Power's obligations for capital – growth projects include Genesee 4 and 5 and excludes interest to fund construction and refundable transmission system contribution payments.

2 Capital Power's obligation to make payments on a monthly basis for fixed and variable costs under the terms of its acquired PPAs will vary depending on generation volume and scheduled plant outages. Fixed costs include fixed operation and maintenance expenditures, fuel, depreciation, decommissioning, return on equity, and return on debt and working capital.

3 Capital Power's decommissioning provisions reflect the undiscounted cash flows required to settle obligations for the retirement of its generation plants and Genesee coal mine.

4 Energy purchase and transportation contracts include natural gas transportation contracts which are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2016 to 2019.

Contingent liabilities

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, among other things, the loss factors to be applied for the years 2006 forward and is expected to be completed in three modules. In January 2015, the AUC issued its decision in Module A of the LLR Proceeding and concluded that it has the jurisdiction and authority to retroactively apply loss factors resulting from a new LLR. Module A was subsequently appealed by multiple parties, including the Company. Principles for the new LLR were considered in Module B and in November 2015, the AUC issued a decision in which it directed the AESO to make several changes to the currently non-compliant LLR including that it be based on an incremental loss factor methodology. The AUC also directed the AESO to file a plan and timeline for a revised LLR incorporating this new methodology and on February 1, 2016, the AESO indicated that it will work to develop and implement the new LLR by January 1, 2017. Module C of the LLR Proceeding will address the compensation to be paid or received by the various parties. As at February 18, 2016, no retroactive loss factors have been produced by the AESO using the new LLR nor has any 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 is unknown. Capital Power may incur material additional transmission charges on a retrospective and go-forward basis but a provision has not been recorded in the Company's audited 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% (see Significant Events). The City of Edmonton, as the sole shareholder of EPCOR, was also a related party of Capital Power until April 2, 2015.

The following table presents the related party transactions between Capital Power and its related parties for the period from January 1, 2015 to April 2, 2015 compared with the year ended December 31, 2014.

The 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 period from January 1, 2015 to April 2, 2015 and the year ended December 31, 2014 based on EPCOR's unitholdings during those periods.

(unaudited, $ millions)	**Period from January 1, 2015 to April 2, 2015**	**Year ended December 31, 2014**
Revenues – energy sales:		
EPCOR and City of Edmonton	5	13
Energy purchases and fuel:		
EPCOR	-	2
Purchase of raw materials and other services:		
EPCOR	2	8
Finance expense:		
EPCOR	5	13
CPLP distributions paid [1]		
EPCOR	7	24
Repayment of unsecured senior debt payable		
EPCOR	9	8

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

As at December 31, 2015, Capital Power's loans and borrowings payable to EPCOR were $325 million (December 31, 2014 - $334 million). The Company's unsecured senior debt payable to EPCOR, at interest rates ranging from 5.80% to 9.00% per annum, matures between 2016 and 2018. Since EPCOR owns less than 20% of the outstanding limited partnership units of CPLP, EPCOR may, by written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon. If the principal amount specified in such repayment is less than $200 million, then it and the accrued interest thereon shall be payable on or before 180 days after delivery of notice, and if it is $200 million or more, then it and the accrued interest thereon shall be payable on or before 365 days after delivery of notice.

RISKS AND RISK MANAGEMENT

The Company's approach to risk management is to identify, monitor and manage the key controllable risks facing the Company and consider appropriate actions to respond to uncontrollable risks. Risk management includes the controls and procedures for reducing controllable risks to acceptable levels and the identification of the appropriate actions in cases of events occurring outside of management's control. Acceptable levels of risk are established by the Board of Directors of Capital Power and govern the Company's decisions and policies associated with risk. The Board of Directors of Capital Power reviews the Company's risk profile on a semi-annual basis and material changes to the risk profile as required.

Capital Power employs an Enterprise Risk Management Program (ERM Program) to identify, evaluate, report and monitor key risks that may affect the achievement of the Company's strategic and related business objectives. The ERM Program aligns with the International Organization for Standardization's standard for risk management, ISO 31000, and the Company's approach is to undertake risk assessment in conjunction with core corporate processes.

Subject to the oversight of the Board of Directors of Capital Power, risk management is carried out at several levels. The President and Chief Executive Officer (CEO) has ultimate accountability for managing the Company's risks and approves the framework for enterprise risk management. The President and CEO, and the rest of the executive team provide general oversight and policy reviews and recommendations. They meet periodically to review enterprise risk management performance and to evaluate significant or emerging risks. The Risk Oversight Council (consisting of the senior management representatives appointed by the President and CEO) establishes the overall direction, structure, conduct and control of Capital Power's commodity exposure management activities, both in the physical markets and the financial derivatives markets. The Vice President, Risk Management and Internal Audit is responsible for the enterprise risk management framework including developing risk management policies and processes and monitoring the Company's compliance with the policies and processes by performing periodic reviews and internal audits. He is also responsible for the leadership of the commodity and credit risk management (middle office) function, security and contingency planning, as well as insurance risk management. Individual executive risk owners are accountable for carrying out the risk management and mitigation activities associated with the risks in their respective operations. All Capital Power employees are expected to understand the risks that fall within their areas of responsibility and to manage these risks within approved risk tolerances.

Management views risk management as an ongoing process; it continually looks for ways to enhance the Company's risk management processes.

Capital Power's principal risk factors could have an adverse impact on the Company's business, prospects, financial condition, results of operations, cash flow, liquidity, capital expenditures, or resources. Not only do these risks provide Capital Power with exposure to negative consequences but also to the possibility that positive consequences will be missed. The identified risk factors are interdependent and the potential impact of any one factor is generally difficult to quantify as the impact of other risk factors changes at the same time or at a subsequent time. These principal risk factors are discussed below:

Legal, regulatory and stakeholder risk

Capital Power is subject to risk associated with changing political conditions and with changes in federal, provincial, state, or local laws and regulations or common law and their interpretation by administrative tribunals or the courts. It is not possible to predict changes in the legislative and regulatory environment or their impact on the Company's business, income tax status, operations, or the markets in which the Company operates.

The CLP, announced in the fourth quarter of 2015, increases regulatory risk due to the uncertainty in form, timing and amount of compensation for the accelerated closure of coal-fired power plants in Alberta. The Alberta government has committed to avoid stranding capital and that fair compensation will be offered to those entities whose assets will be impacted. The appropriate amount and form of compensation has yet to be determined and, if inadequate, could have adverse impacts on Capital Power. These adverse impacts could include the stranding of Company assets and a limitation on cash flow that could impair future development. The CLP also recommends the replacement of two-thirds of the coal-fired generation with renewables. New renewables construction will be incented through a proposal process offering REC's in addition to the merchant pool price. The timing of these new developments and the price offered to spur development is unknown, however, the existing Alberta merchant market is expected to remain intact.

Capital Power is required to maintain numerous licenses, permits and governmental approvals for the development, construction and operation of its projects and participation in its markets. If Capital Power fails to satisfy the conditions of these instruments, there could be an adverse impact on the effectiveness and cost of those projects or operations. Many of the regulatory approval processes for the development, construction and operation of power generation facilities require stakeholder input. Accordingly, progress in Capital Power's development, construction and operation activities could be impeded by stakeholder intervention. Changes in law and regulatory requirements may also adversely impact the market dynamics for Capital Power, the participation levels of counterparties that Capital Power relies on to support its portfolio optimization strategies and the costs associated with participating in these markets.

Capital Power's assets are emitters of various air pollutants including CO_2, NO_x, SO_2, mercury, and particulate matter. Accordingly, Capital Power's operations are subject to extensive environmental laws, regulations and guidelines relating to the generation and transmission of electricity, pollution and protection of the environment, health and safety, air emissions, water usage, wastewater discharges, hazardous material handling and storage, treatment and disposal of waste and other materials, remediation of sites, and land-use responsibility.

These regulations can impose liability for costs to investigate or remediate contamination. Compliance with new regulatory requirements may require Capital Power to incur significant capital expenditures or additional operating expenses or cause operations at certain facilities to end prior to the end of their economic life, and failure to comply with such regulations could result in fines, penalties or the curtailment of operations. Further, there can be no assurance that compliance with or changes to environmental regulations will not materially adversely impact Capital Power's business, prospects, financial condition, operations or cash flow.

Capital Power's ability to develop new projects is also affected by the availability of transmission and distribution systems. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure. Capital Power cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

Capital Power's operations are complex and the determination of income taxes involves income tax interpretations, regulations and legislation that are continually changing. Future changes in tax legislation may have an adverse impact on Capital Power, its shareholders and the value of the Company's common shares.

Strategies employed for managing legal, regulatory and stakeholder risk:

- Identify existing, new or changed laws or regulations and prepare appropriate responses or plans.
- Comply with all applicable laws, regulations and guidelines and monitor compliance.
- Perform environmental compliance audits with corrective actions as necessary.
- Establish positive relationships with all levels of government and stakeholders.
- Consult with all levels of government, including the government appointed facilitator of the CLP, with respect to policy development and current and proposed legislation.
- Execute on-time permitting, license renewals and other activities associated with laws and regulations.
- Proactively identify environmental risks within operations, maintenance and construction activities and promote awareness throughout and at all levels of the Company.
- Ensure that contractors align with Capital Power's environmental policies and procedures.
- Support the timely development of appropriate transmission capability through active relationships with regulators and government.
- Develop and maintain tax expertise and resources necessary to interpret tax legislation.
- Consult with government with respect to tax policy development and proposed legislation.

Performance of assets of acquired PPA and joint arrangements risk

Some of Capital Power's assets are operated through an acquired PPA and joint arrangements under which Capital Power is not the operator of the associated assets. There is a risk that the assets will not be operated in accordance with Capital Power's expectations or requirements which could result in financial loss to the Company. While contractual agreements help minimize risk, there can be no assurance that such operations will continue to be effective.

The occurrence of an event which disrupts the ability of the Sundance power plants to produce or sell power or thermal energy for an extended period under the Sundance PPA would likely require Capital Power to replace the electricity at market prices prevailing at that time, although it would be relieved of the obligation to pay the unit capacity fee. Depending on market liquidity, these market prices could be significantly higher than the prices inherent in the Sundance PPA, thus increasing the cost of energy purchases to Capital Power. Similar factors could affect Capital Power's generation plants that are operated by third parties.

Strategies employed for managing acquired PPA and joint arrangements risk:

- Work with plant owner and/or operator to execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time.
- Measure performance against benchmarks.
- Actively participate in management committees of joint operations.
- Proactively manage the contract's rights and obligations based on thorough understanding of the contract.
- Proactively assess and resolve any contract issues including force majeure claims and appropriately respond with dialogue, advocacy, negotiation, arbitration and legal actions, as required.

Commodity price volatility

The market price for electricity, in the jurisdictions and markets in which Capital Power operates, affects Capital Power's revenues. Capital Power buys and sells some of its electricity in the Alberta wholesale market and such transactions are settled at spot market prices. Market electricity prices are dependent upon a number of factors including: the projected supply and demand of electricity, the price of raw materials that are used to generate electricity, the cost of complying with applicable environmental and other regulatory requirements, the structure of the particular market, and weather conditions. Natural gas price levels may impact power prices in the markets that the Company participates in. It is not possible to predict future electricity prices with certainty, and electricity price volatility could therefore have a material effect on Capital Power.

Electricity sales associated with the PPA for Genesee 1 and 2 are accounted for as long-term fixed margin contracts, which limits the impact of swings in wholesale electricity spot prices, unless plant availability drops significantly below the PPA target availability for an extended period. Electricity sales and steam sales associated with the Joffre facility located at the Nova Chemicals Company (NOVA) petrochemical complex are subject to market price variability as there are provisions in the contract with NOVA that require the facility to run to provide steam to the host facility, irrespective of market prices. Although the Company's 50% interests in Genesee 3 and Keephills 3 are not covered by long-term commercial contracts, the units are baseload coal-fired generating plants with relatively low variable costs and generally run when they are available, before considering the potential impact of the CLP. For the Company's Genesee 3, Keephills 3, CBEC and Joffre plants, and the acquired Sundance PPA plant, spot electricity prices, the plants' variable costs, and planned and unplanned outages affect profitability.

Capital Power uses derivative instruments, including futures, forwards, options and swaps, to manage its commodity and financial market risks inherent in its electricity generation operations. These activities, although intended to mitigate price volatility, expose Capital Power to other risks. When Capital Power sells power forward, it gives up the opportunity to sell power at potentially higher prices in the future. Selling forward may also result in losses if the underlying price to provide replacement power, in the event of an outage, turns out to be greater than the contract price. In addition, Capital Power purchases and sells commodity-based contracts in the natural gas and electricity markets for trading purposes. In the future, Capital Power could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities.

Capital Power is exposed to market risks through its power marketing business, which involves the sale of energy, capacity and related products, and the purchase and sale of fuel, transmission services and emission allowances. These market risks primarily include volatility arising from location and from timing differences that may be associated with buying and transporting fuel, converting fuel into energy and delivering the energy to a buyer.

When aggregate customer electricity consumption (load shape) changes unexpectedly, Capital Power is exposed to price risk. Load shape refers to the different pattern of consumption between peak hours and off-peak hours. Consumption is higher during peak hours when people and organizations are most active; conversely, consumption is lower during off-peak hours at night or early morning.

Strategies employed for managing commodity price volatility risk:

- Execute Company's growth strategy and re-contract generation plants under new or extended contracts to maintain a balance of contracted and non-contracted plants.
- Limit exposure to market price volatility by entering into long-term power contracts on certain of our generation units.
- Maintain a commodity risk management program which provides the infrastructure to manage commodity and trading risks associated with the commodity business.
- Take market risk positions within authorized limits approved by Capital Power's executive team and Board of Directors.
- Report daily key risk measures in relation to applicable limits to the executive team with quarterly review by the Board of Directors of Capital Power.
- Perform regular commodity portfolio stress testing to observe the effects of plausible scenarios taking into account historical maximum volatilities and observed price movements.
- Minimize exposure to extreme price fluctuations, especially during higher priced peak hour periods. To do this, Capital Power relies on historical load shape data provided by load settlement agents and local distribution companies to anticipate what the aggregate customer electricity consumption will be during peak hours. When consumption varies from historical consumption patterns and from the volume of electricity purchased for any given peak hour period, Capital Power is exposed to prevailing market prices because it must either buy electricity if it is short or sell electricity if it is long. Such exposures can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.
- Limit exposure to spot price variability within specified risk limits by entering into various purchase and sale arrangements for periods of varying duration. Due to limited market liquidity and the variability of electricity consumption between peak hours and off-peak hours, it is not possible to hedge all positions every hour. The Company operates under specific policy limits, such as total commodity risk and stop-loss limits, and generally trades in electricity to reduce the Company's exposure to changes in electricity prices or to match physical or financial obligations.

Operation and maintenance of equipment and systems risk

Power plant operations are susceptible to outages due to failure of generation equipment, transmission lines, pipelines or other equipment, which could make the impacted plant unavailable to provide service.

The inability of Capital Power's power plants to generate the expected amount of electricity to be sold under contract or to the applicable market could have a significant adverse impact on the Company's revenues. In addition, counterparties to PPAs have remedies available to them if Capital Power fails to operate facilities in accordance with contract requirements, including the recovery of damages and termination of contractual arrangements. To the extent that plant equipment requires significant capital and other operation and maintenance expenditures to maintain efficiency, requires longer than forecast down-times for maintenance and repair, experiences outages due to equipment failure or suffers disruptions of power generation for other reasons, Capital Power's cost of generating electricity will increase and its revenues may be negatively affected. As an adopter of new technology, Capital Power can be exposed to design flaws or other issues, the impacts of which may not be covered by warranties or insurance. The failure of Capital Power's facilities to operate at required capacity levels may result in the facilities having their contracted capacity reduced and, in certain cases, Capital Power having to make payments on account of reduced capacity to power purchasers.

The terms of the PPAs for owned plants and the acquired Sundance PPA provide appropriate incentives to plant owners to keep the plants well maintained and operational. They also provide force majeure protection for high-impact, low-probability events including major equipment failure.

Many of Capital Power's generation plants operate under PPAs or other similar contracts which are subject to a number of risks. PPA contracts contain performance benchmarks that must be achieved and other obligations that must be complied with by Capital Power. Capital Power may incur charges in the event of unplanned outages or variations from the contract performance benchmarks. PPAs expire at various times and there can be no assurance that a subsequent PPA will be available or, if available, that it will be on terms, or at prices that permit the operation of the facility on a profitable basis.

Capital Power depends on transmission facilities owned and operated by third parties to deliver the wholesale power from its power generation plants to its customers. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, there may be a material adverse effect on Capital Power's ability to sell and deliver wholesale power.

Capital Power employs several key computer application systems to support its operations, such as electricity plant control, energy trading risk management, and enterprise resource planning systems. Failure of any of these systems, during or after implementation, could result in significant lost revenues, increased costs or regulatory fines. Capital Power is also susceptible to the external risk of unauthorized access to and/or penetration of its computer networks and applications.

Strategies employed for managing operation and maintenance of equipment and systems risk:

- Establish long-term service agreements with original equipment manufacturers on key assets. Should a LMS 100 unit at CBEC fail, down time is reduced by replacing a failed unit with a replacement unit provided by the manufacturer under the terms of the long-term service agreement with that manufacturer.
- Ensure constructive relationships with original equipment manufacturers.
- Execute appropriate operating and maintenance practices (reliability program) to minimize the likelihood of prolonged unplanned down time for the Company's plants.
- Maintain an inventory of strategic spare parts which can reduce down time in the event of failure.
- Employ a root cause analysis program to ensure that problems are properly identified and addressed and that learnings are shared across the fleet.
- Establish and maintain appropriate business interruption, property, and boiler and machinery insurance to reduce the impact of prolonged outages caused by insured events.
- Minimize the customization of commercial software, monitor the impacts on processes and internal controls and undertake remedial actions, as required.
- Ensure operations and implementation projects are properly resourced with qualified and trained staff and contractors.
- Employ robust firewalls and access security protocols as well as detection systems that will identify or prevent unauthorized systems or devices.

People risk

Capital Power's ability to continuously operate its facilities and grow the business is dependent upon attracting, retaining and developing sufficient labour and management resources. Capital Power is experiencing a demographic shift as a significant number of its employees are expected to retire over the next several years**.** Failure to secure sufficient qualified labour may negatively impact Capital Power's operations or construction and development projects, or may increase expenses. Capital Power's current collective bargaining agreements expire periodically and Capital Power may not be able to renew them without a labour disruption or without agreeing to significant increases in labour costs.

In the fourth quarter of 2015, the Company concluded a new collective agreement with CSU 52, which represents certain administrative, technical, professional, and information technology employees located in the Edmonton corporate office and the Genesee power plant. This agreement will expire in 2018.

In the second quarter of 2015, the Company concluded a new collective agreement with UNIFOR 1123, which represents all employees directly engaged in the maintenance of the electrical generation at Island Generation. This agreement will expire in 2021.

The Company's collective agreement with IBEW 007, which represents all employees directly engaged in the maintenance of the electrical generation at Genesee, expired December 12, 2015. All existing terms, conditions and wage rates in the expired collective agreement will continue in force and effect until a new collective agreement is concluded. Negotiations related to a new collective agreement are expected to occur in the first half of 2016.

Strategies employed for managing human resources risk:

- Maintain good human resource programs and practices including monitoring developments and contingency plans.
- Maintain competitive compensation programs.
- Maintain good collective bargaining capability, programs and practices.

The development, construction, ownership and operation of Capital Power's generation assets carry an inherent risk of liability related to public health, and worker health and safety due to exposure to high voltage electricity, high pressure steam, moving and rotating machinery, heavy equipment, driving, and environmental hazards.

Strategies employed for managing health and safety risk:

- Maintain an organization-wide health and safety culture and system with regular measurements and compliance audits.
- Maintain facility specific safety programs and work procedures.
- Ensure that contractors and other stakeholders align with Capital Power's health and safety policies and procedures.

Capital Power strives to right size the resources required to operate and grow in its markets and minimize the cost of those resources. Failure to do so could negatively impact culture, growth and earnings and place the Company at a competitive disadvantage.

Strategies employed for managing cost optimization and efficiency risk:

- Set performance targets and measure and report results compared with those targets. Measure performance against benchmarks.
- Develop and undertake efficiency initiatives and programs.
- Support internal resources by utilizing retention programs and assessing employee engagement with appropriate communication and follow-up.

Finance risk

Capital Power's ability to fund current and future capital requirements, along with its working capital needs is dependent upon access to financial markets. Uncertainty and volatility in the Canadian and U.S. financial markets may adversely affect Capital Power's ability to access and arrange financing under favourable terms and conditions. The cost of capital will also depend upon prevailing market conditions and the business performance of Capital Power as indicated by the assigned corporate credit ratings (see Liquidity and Capital Resources). If Capital Power is unable to access sufficient amounts of capital on acceptable terms, there could be an adverse effect on its business plan and financial condition.

Strategies employed for managing credit rating risk:

- Maintain strong relationships with credit rating agencies.
- Develop flexible financial structuring to adapt if circumstances would cause a credit rating downgrade from investment grade.

When Capital Power uses financial instruments to sell power forward, it may be required to post significant amounts of cash collateral or other credit support to its counterparties.

Strategies employed for managing liquidity risk:

- Monitor cash and currency requirements on a regular basis by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements.
- Maintain strong relationships with banks, investment banks and other financial counterparties.
- Meet financing requirements through a combination of committed and demand revolving credit facilities, financings in public and private capital debt markets, and equity offerings.

Counterparty risk is the possible financial loss associated with the potential inability of counterparties to satisfy their contractual obligations to Capital Power, including payment and performance. In the event of default by a purchasing counterparty, existing PPAs and other agreements may not be replaceable on similar terms. Capital Power is also dependent upon its cogeneration hosts and suppliers of fuel to its plants. If a wholesale electricity market counterparty defaults, Capital Power may not be able to replace such counterparty to effectively manage short or long energy positions, resulting in reduced revenues or increased power costs. Furthermore, a prolonged deterioration in economic conditions could increase the foregoing risks.

Strategies employed for managing counterparty credit risk:

- Maintain a credit policy including limits for credit risk exposure levels.
- Conduct periodic credit reviews on existing counterparties.
- Use credit enhancements such as cash deposits, prepayments, parent company guarantees, bank letters of credit, master netting agreements, margin accounts and credit derivatives.
- Monitor and report credit risk exposures.

Extreme natural and other unexpected events risk

Capital Power’s operations are exposed to potential damage resulting from extreme storm and other weather conditions and natural disasters. In addition, major accidents or events including environmental incidents, cyber-attacks, and physical terrorist attacks are possible and the negative consequences could be significant.

Strategies employed for managing extreme events risk:

- Establish and maintain emergency and other related contingency planning measures to enable the timely response to and recovery from extreme weather and other events.
- Maintain appropriate insurance coverage.

Competition, acquisition, development and construction risk

In the course of assessing development and acquisition opportunities, Capital Power may be required to incur significant expenditures, such as those related to preliminary engineering, permitting, legal and other expenses, before determining whether a project is feasible and economically viable. There can be no assurance that Capital Power will pursue or win any opportunity assessed.

The risks associated with acquisitions of additional companies or assets in the power generation industry include the failure to identify material problems during due diligence, the overpayment for assets and the inability to arrange financing for an acquisition. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will cover the cost of financing incurred to acquire them or the capital expenditures needed to develop them.

In developing and constructing a power generation facility, there are numerous tasks Capital Power must complete. These include obtaining government permits and approvals, site agreements, construction contracts, access to power grids, electrical transmission agreements, fuel supply and transportation agreements, equipment, and financing. There can be no assurance that Capital Power will be successful in completing such tasks on a timely basis or at all. The development and future operation of power generation facilities can be adversely affected by changes in government policy and regulation, environmental concerns, stakeholder activism, increases in capital costs, increases in interest rates, competition in the industry, labour availability, labour disputes, increases in material costs and other matters beyond the control of Capital Power. In the event that a project is not completed or does not operate at anticipated performance levels, Capital Power may not be able to recover its investment.

Strategies employed for managing competition, acquisition, development, and construction risk:

- Perform detailed project analyses, risk assessments and due diligence prior to and during construction or acquisition.
- Perform post-implementation evaluation of all major acquisition and development projects to improve internal capabilities and processes and to leverage lessons learned for future projects. When necessary, corrective actions are taken to increase the likelihood of investment recovery.
- Enter into favourable long-term contracts for the projects’ output, whenever possible.

Ongoing research and development activities improve upon existing power technologies and reduce the cost of alternative methods of power generation. As identified by ongoing research and development activities, Capital Power’s plants may over time be unable to compete with newer more efficient plants utilizing improvements to existing power technologies and cost-efficient new technologies.

Energy supply risk

Capital Power requires energy from sources such as coal, natural gas, wind, wood waste and tire derived fuel and the sun to generate electricity. A disruption in the supply or a significant increase in the price of any supplies required by Capital Power could have a material adverse impact on Capital Power's business, financial condition and results of operation. The price of fuel supplies is dependent upon a number of factors, including: (i) the supply and demand for such fuel supplies, (ii) the quality of the fuel, and (iii) the cost of transporting such fuel supplies to Capital Power’s facilities. Changes in any of these factors could increase Capital Power's cost of generating electricity or decrease Capital Power’s revenues due to production cutbacks.

Coal for the Genesee and Keephills 3 plants is supplied under long-term agreements where the price is based on a cost-of-service model with annual updates for inflation, interest rate and capital budget parameters and is therefore not subject to coal market price volatility. A shortage of coal supply resulting from significant disruption of the coal mine equipment and operation could negatively impact generation and revenues from these plants. Most of Capital Power's natural gas-fired plants are operated as merchant facilities and as such are susceptible to the risks associated with the volatility of natural gas prices and the prevailing electricity market prices. Natural gas purchases for these power plants are made under variable price contracts and when a facility’s heat rate (a measure of fuel efficiency) does not meet expectations, unit profitability is affected. Island Generation operates under a long-term PPA with fuel cost flow-through provisions.

Capital Power's wind power facilities are dependent on the availability and constancy of sufficient wind resources to meet projected capacity factors. Fluctuations in wind speed or duration could have a material negative impact on revenues for these facilities in any year.

Strategies employed for managing energy supply risk:

- Establish long-term supply agreements.
- Maintain coal stock-pile inventories.
- Establish contracts with fuel cost flow-through provisions, where possible.
- Actively participate on the Genesee Coal Mine Joint Venture Committee and exercise contractual rights as required.

General economic conditions, business environment and other risks

In addition to all the risks previously described, the Company is subject to adverse changes in its markets and general economic conditions. The Company is exposed to risks associated with income tax filings, foreign exchange, weather, legal and arbitration proceedings, and risks that are not fully covered by various insurance policies.

Environmental risk is incorporated in several different types of risks discussed in this and other subsections of this Risk and Risk Management section including legal, regulatory and stakeholder risk, people risk, operation and maintenance of equipment and systems risk, extreme natural and other unexpected occurrences, energy supply risk, and reputation risk.

Capital Power's tax filings are subject to audit by taxation authorities. While Capital Power maintains that its tax filings have been made in accordance with all such tax interpretations, regulations, and legislation, Capital Power cannot guarantee that it will not have disagreements with taxation authorities with respect to its tax filings.

The statutory income tax rates on income before tax for 2015 and 2014 were 26% and 25%, respectively. The effective income tax rate can change depending on the mix of earnings from various jurisdictions, and on deductions and inclusions in determining taxable income that do not fluctuate with earnings.

Strategies employed for managing tax compliance risk:

- Develop and maintain tax expertise and resources necessary to understand tax legislation.
- Comply with tax laws of jurisdictions that Capital Power operates in.

Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar affect Capital Power's capital and operating costs, revenues and cash flows and could have an adverse impact on Capital Power's financial performance and condition. The U.S. plant operations and the foreign-sourced equipment required for capital projects are transacted in U.S. dollars. In addition, certain indebtedness is denominated in U.S. dollars.

Strategies employed for managing foreign exchange risk:

- Utilize foreign currency forward contracts.
- Contract significant purchases or borrowings in Canadian dollars.
- Utilize U.S. dollar denominated debt to finance U.S. acquisitions and developments.

The Company is dependent upon cash dividends, distributions or other transfers from its subsidiaries, including CPLP, in order to repay any debt the Company may incur, to make dividend payments to its shareholders and meet its other obligations. The right of the Company, as a unitholder or shareholder of these entities, to realize on the assets of these entities in the event of their bankruptcy or insolvency, would be subordinate to the rights of their creditors and claimants preferred by statute. CPLP's credit facilities prohibit CPLP from making distributions, if an event of default has occurred and is continuing or would reasonably be expected to result from the distribution. As of December 31, 2015, the Company loaned $1,010 million to CPLP under subordinated debt agreements. The terms of this agreement allow interest to be deferred. If interest is deferred, then CPLP has covenanted not to make distributions on any of its outstanding common limited partnership units.

Weather can have a significant impact on Capital Power's operations. Temperature levels, seasonality and precipitation, both within Capital Power's markets and adjacent geographies, can affect the level of demand for electricity and natural gas, thus resulting in electricity and natural gas price volatility.

In the normal course of Capital Power's operations, it may become involved in various legal proceedings including arbitration of the interpretation of any contract. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty. However, the Company does not believe that the outcome of any claims or potential claims of which it is aware will have a material adverse effect on Capital Power's financial condition and results of operations (see Contractual Obligations and Contingent Liabilities).

The Company considers reputation risk to be a consequence of all other risks that it faces. If a certain risk factor results in positive or negative consequences to the Company, its reputation may also be positively or negatively affected. In part, the Company manages its reputation risk by employing appropriate risk management strategies for all identified risks.

Capital Power's property, boiler and machinery, business interruption and liability insurance coverages are established and maintained to minimize financial exposures associated with extreme weather and other events. The insurance coverages are subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these and other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis or that all events that could give rise to a loss or liability are insurable.

There can be no assurance that any risk management steps taken by Capital Power with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $184 million as at December 31, 2015 ($161 million as at December 31, 2014) for its generation plants and the Genesee coal mine as it is obliged 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 to purchase environmental credits totaling approximately $107 million in 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 audited consolidated financial statements, management made judgments, estimates and assumptions that affect the application of the Company's accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively.

Critical judgments in applying accounting policies

The main judgments that were used in preparing the Company's audited consolidated financial statements relate to:

Judgment	Management applies judgment to evaluate	Resulting conclusions
Cash generating units (CGUs)	What constitutes a CGU based on the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.	CGUs were determined giving consideration to geographic proximity and shared risk exposure and risk management.
Asset impairment	Whether events or circumstances may indicate that an asset's carrying amount exceeds its recoverable amount.	In 2015, the Company tested its Alberta Commercial and Alberta Contracted CGUs for impairment during the fourth quarter of 2015. The uncertainties created by the CLP are not themselves triggering events for purposes of assessing potential asset impairments. However, these uncertainties, 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 in the latter half of 2015. The Company determined that no other CGUs were affected by the triggering events, since they operate in geographic regions that are not directly impacted by the events in Alberta. As a result of the test, no impairment was recognized.
Whether an arrangement contains a lease and classification of leases	Whether a PPA or similar contract conveys the right to use the Company's property, plant and equipment in return for payment, and, if so, a lease exists. Whether substantially all the risks and rewards of ownership of property are transferred to determine if the lease is accounted for as a finance lease or, if not, the lease is accounted for as an operating lease.	Contracts that convey the right to use Capital Power's property, plant and equipment and, therefore, contain a lease: 1. **Finance leases as the lessor** (substantially all the risks and rewards are transferred) • Kingsbridge energy supply contract • Port Dover and Nanticoke energy supply contract • Quality Wind electricity purchase agreement 2. **Operating leases as the lessor** (substantially all the risks and rewards remain with Capital Power) • Genesee 1 and 2 PPA • Island Generation PPA • Roxboro PPA 3. **Finance lease as the lessee** (substantially all the risks and rewards remain with Capital Power) • Beaufort Solar sale and leaseback agreement
Control of subsidiaries that are less than wholly-owned	Whether certain subsidiaries are controlled by the Company even though the subsidiaries are less than wholly-owned.	Since the Company has majority rights, the Genesee Coal Mine is consolidated and has non-controlling interests.
Classification of joint arrangements	How joint arrangements structured through a separate vehicle should be classified; either as a joint venture or a joint operation.	K2 Wind is accounted for as a joint venture because each of the partners effectively has rights to the net assets of the arrangement. Genesee 3, Keephills 3, Joffre, Shepard and Genesee 4 and 5 are accounted for as joint operations because each of the joint operators has rights to the assets and obligations for the liabilities of the arrangement and rights to the corresponding revenues and obligations for the corresponding expenses.

Assumptions and estimation uncertainties

The following identifies key information about assumptions and estimation uncertainties that could have a significant risk of resulting in material adjustments:

Estimate	Impacts and assumptions subject to estimation uncertainty
Measurement of fair values	Carrying amounts for financial instruments • Amounts and timing of future cash flows • Future prices • Future interest rate yield curves • Volatility
	Impairment of financial and non-financial assets and liabilities • Discount rates • Growth rates • Other cash flow assumptions including revenues, expenses and capital expenditures • Future generating capacity • Contract renewals and rates adjusted for inflation • Fuel mix at optimized levels
	Decommissioning and other provisions • Discount rates • Amount and timing of asset retirement • Extent of site remediation required • Future cash flows based on amount and timing of settlement of obligation • Expected customer renewals for other provisions
	Share-based payments • Expected volatility, option life and dividend yield • Risk-free interest rate
	Purchase price allocations to financial and non-financial assets and liabilities • Same fair value measurement factors and assumptions as applicable to determine carrying amounts for derivative financial instruments, impairment of financial and non-financial assets and liabilities, and decommissioning and other provisions
Depreciation and amortization	Asset's useful life based on the life characteristics of common assets and enactment of the CLP
Recognition of deferred tax assets and availability of future taxable income against which carryforward tax losses can be used.	Deferred tax assets and income tax provisions based on likelihood that tax losses will be recovered from future taxable income
Revenue recognition	Value of electricity and natural gas consumed by customers but not billed until after year-end based on data provided by the parties delivering the commodity

ACCOUNTING CHANGES

Effective January 1, 2015

There were no significant changes to accounting standards that were effective January 1, 2015 and that were adopted or applied by the Company.

Future

The IASB issued the following new standards and amendments to existing standards that were not yet effective as of December 31, 2015 and are relevant to Capital Power:

Standard	Description	Impact to Capital Power	Effective Date
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 profit or loss and other comprehensive income or loss, and providing additional examples of ways of ordering notes.	Capital Power is currently analyzing the requirements to determine how best to apply them.	Effective for annual periods beginning on or after January 1, 2016; early application permitted.
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 IRFS 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.	Effective for annual periods beginning on or after January 1, 2016; early application permitted.
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 December 31, 2015 and 2014 were as follows:

(unaudited, $ millions)			As at December 31			
		Fair value hierarchy level [1]	2015		2014	
	Classification		Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:						
Cash and cash equivalents	Loans and receivables	N/A	80	80	71	71
Trade and other receivables	Loans and receivables	N/A	190	190	185	185
Derivative financial instruments assets – current and non-current	Financial assets designated at fair value through income or loss	Level 2	220	220	187	187
Finance lease receivables	Loans and receivables	Level 2	689	786	708	712
Other financial assets	Loans and receivables	Level 2	12	12	16	17
Financial liabilities:						
Trade and other payables	Other financial liabilities	N/A	181	181	185	185
Derivative financial instruments liabilities – current and non-current	Financial liabilities designated at fair value through income or loss	Level 2	53	53	74	74
Finance lease obligation (including current portion)	Other financial liabilities	Level 2	22	22	-	-
Loans and borrowings (including current portion)	Other financial liabilities	Level 2	1,615	1,623	1,586	1,670

[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 by the Company's commodity risk group and reviewed by management. As at December 31, 2015 and December 31, 2014, the Company did not classify any financial instruments in Level 3 of the fair value hierarchy.

Risk management and hedging activities

The Company is exposed to changes in energy commodity prices, foreign currency exchange rates and interest rates. The Company uses various risk management techniques, including derivative instruments such as forward contracts, fixed-for-floating swaps, and option contracts, to reduce this exposure. These derivative instruments are recorded at fair value on the Consolidated Statements of Financial Position except for non-financial derivatives that are entered into and continue to be held for the purpose of receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements.

Unrealized changes in the fair value of financial and non-financial derivatives that do not qualify for hedge accounting and non-financial derivatives that do not qualify for the expected purchase, sale or usage requirements of the contract are recognized in net income as revenues or energy purchases and fuel. The corresponding unrealized changes in the fair value of the associated economically hedged exposures are not recognized in income. Accordingly, derivative instruments that are recorded at fair value can produce volatility in net income as a result of fluctuating forward commodity prices, foreign exchange rates and interest rates which are not offset by the unrealized fair value changes of the exposure being hedged on an economic basis. As a result, accounting gains or losses relating to changes in fair values of derivative instruments do not necessarily represent the underlying economics of the hedging transaction.

For example, the Company usually has more physical supply of power in Alberta from its generating units and power purchased under PPAs than the Company has contracted to physically sell. The Company utilizes financial sales contracts to reduce its exposure to changes in the price of power in Alberta. Economically, the Company benefits from higher Alberta power prices due to the net long position held since the Company's expected physical supply is in excess of the Company's physical and financial sales contracts. However, financial sales contracts that are not hedged for accounting purposes are recorded at fair value at each statement of financial position date and the offsetting anticipated future physical supply or economically hedged item is not. Accordingly, an increase in forward Alberta power prices can result in fair value losses for accounting purposes whereas on an economic basis, these losses are offset by unrecognized gains on the physical supply. The economic gains will be recognized in later periods when the power is produced and sold. The opposite is true for forward price decreases in Alberta power.

The derivative financial instruments assets and liabilities held at December 31, 2015 and 2014 and used for risk management purposes were measured at fair value and consisted of the following:

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

(unaudited, $ millions)	As at December 31, 2014				
	Commodity cash flow hedges	Commodity non-hedges	Foreign exchange hedges	Interest rate non-hedges	Total
Derivative financial instruments assets	53	109	21	4	187
Derivative financial instruments liabilities	(3)	(66)	-	(5)	(74)
Net derivative financial instruments assets (liabilities)	**50**	**43**	**21**	**(1)**	**113**

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 income and, when realized, are reclassified to net income as revenues, energy purchases and fuel or foreign exchange gains and losses.

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

As at December 31, 2015, management conducted an evaluation of the design and operation of the Company's disclosure controls and procedures to provide reasonable assurance that:

(i) material information relating to the Company is made known to management by others, particularly during the period in which the Company's annual filings are being prepared, and

(ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The evaluation took into consideration the Company's Disclosure Policy and internal sub-certification process, and the functioning of its Disclosure Committee. In addition, the evaluation covered the Company's processes, systems and capabilities relating to public disclosures and the identification and communication of material information. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are appropriately designed and effective.

As at December 31, 2015, management conducted an evaluation of the design and operation of internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's internal controls over financial reporting are appropriately designed and effective.

These evaluations were conducted in accordance with the Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

SUMMARY OF QUARTERLY RESULTS

(GWh)	Three months ended							
Electricity generation	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**
Total generation excluding acquired Sundance PPA	3,929	3,687	3,553	3,398	3,204	3,220	2,711	3,241
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	500	498	491	493	369	473	438	466
Keephills 3	489	258	436	457	433	461	381	399
Clover Bar Energy Centre 1, 2 and 3	41	39	98	70	45	77	66	108
Joffre	84	62	76	86	58	77	71	118
Shepard	387	572	443	60	N/A	N/A	N/A	N/A
Halkirk	129	88	107	136	146	86	92	138
Clover Bar Landfill Gas	1	2	3	2	3	3	5	3
Alberta commercial plants – owned	1,631	1,519	1,654	1,304	1,054	1,177	1,053	1,232
Acquired Sundance PPA	717	688	565	691	819	673	521	750
	2,348	2,207	2,219	1,995	1,873	1,850	1,574	1,982
Alberta contracted plants								
Genesee 1	842	865	608	815	857	854	771	678
Genesee 2	861	843	838	836	856	841	546	832
	1,703	1,708	1,446	1,651	1,713	1,695	1,317	1,510
Ontario and British Columbia contracted plants								
Island Generation	5	37	37	-	9	6	-	115
K2 Wind	102	46	19	N/A	N/A	N/A	N/A	N/A
Kingsbridge 1	36	13	21	31	35	14	22	34
Port Dover and Nanticoke	95	44	69	91	91	51	66	93
Quality Wind	121	97	82	108	101	71	80	97
	359	237	228	230	236	142	168	339
U.S. contracted plants								
Roxboro, North Carolina	77	76	70	59	74	73	58	39
Southport, North Carolina	131	128	118	129	122	133	115	121
Beaufort Solar, North Carolina	-	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Macho Springs, New Mexico	28	19	37	25	5	N/A	N/A	N/A
	236	223	225	213	201	206	173	160

(%)	Three months ended							
Plant availability	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**
Total average plant availability excluding acquired Sundance PPA	99	95	90	98	94	97	92	94
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	100	100	100	100	74	97	96	96
Keephills 3	100	63	97	100	92	100	100	100
Clover Bar Energy Centre 1, 2 and 3	97	88	95	97	90	97	98	97
Joffre	100	100	87	99	82	95	95	100
Shepard	98	100	73	80	N/A	N/A	N/A	N/A
Halkirk	96	97	98	99	98	91	98	96
Clover Bar Landfill Gas	84	81	93	100	87	58	83	75
Alberta commercial plants – owned	98	92	89	97	87	96	97	98
Acquired Sundance PPA	92	91	79	92	96	85	67	89
	96	92	86	95	91	91	84	94
Alberta contracted plants								
Genesee 1	99	100	72	98	100	100	96	83
Genesee 2	100	98	100	100	100	99	66	93
	100	99	86	99	100	99	81	88
Ontario and British Columbia contracted plants								
Island Generation	100	100	100	100	100	99	100	100
K2 Wind	99	98	98	N/A	N/A	N/A	N/A	N/A
Kingsbridge 1	98	94	95	97	96	93	97	95
Port Dover and Nanticoke	98	95	97	99	97	98	94	98
Quality Wind	98	94	97	98	98	93	99	95
	99	97	98	99	98	97	98	98
U.S. contracted plants								
Roxboro, North Carolina	99	94	87	97	100	100	96	90
Southport, North Carolina	93	94	88	89	88	85	93	99
Beaufort Solar, North Carolina	100	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Macho Springs, New Mexico	96	96	99	99	99	N/A	N/A	N/A
	96	95	91	94	92	90	94	96

Financial results

(unaudited, $ millions)	Three months ended							
	Dec 31 2015	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**
Revenues								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	199	237	130	216	178	119	127	188
Alberta contracted plants	70	72	67	66	69	76	58	63
Ontario and British Columbia contracted plants	40	23	25	36	36	21	25	37
U.S. contracted plants	30	29	28	27	22	22	22	17
Corporate [1]	1	2	4	1	2	2	21	2
Unrealized changes in fair value of commodity derivatives and emission credits	1	106	(171)	12	125	8	(13)	1
	341	**469**	**83**	**358**	**432**	**248**	**240**	**308**
Adjusted EBITDA								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	70	72	49	63	60	49	43	59
Alberta contracted plants	45	52	45	42	41	44	34	42
Ontario and British Columbia contracted plants	32	16	19	30	29	15	18	30
U.S. contracted plant	10	6	6	5	1	3	3	-
Corporate	(24)	(25)	(27)	(24)	(27)	(25)	(7)	(25)
Unrealized changes in fair value of commodity derivatives and emission credits	(12)	27	(47)	31	37	5	(13)	7
	121	**148**	**45**	**147**	**141**	**91**	**78**	**113**

[1] Revenues are offset by interplant category revenue eliminations.

Quarterly revenues, net income and cash flows from operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, and planned and unplanned 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							
	Dec 31 2015	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**
Revenues	341	469	83	358	432	248	240	308
Adjusted EBITDA [1]	121	148	45	147	141	91	78	113
Net income (loss)	34	50	(48)	50	48	(57)	21	38
Net income (loss) attributable to shareholders of the Company	35	49	(34)	40	39	(45)	20	32
Basic earnings (loss) per share ($)	0.29	0.44	(0.39)	0.41	0.40	(0.62)	0.17	0.33
Normalized earnings per share ($) [1]	0.42	0.33	0.10	0.32	0.20	0.12	0.07	0.32
Funds from operations [1]	125	97	70	108	102	83	85	92
Purchase of property, plant and equipment and other assets	17	36	35	52	57	25	63	75

[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.

	Three months ended							
Spot price averages	**Dec 31 2015**	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**
Alberta power ($ per MWh)	21	26	57	29	30	64	42	61
Alberta natural gas (AECO) ($ per Gj)	2.35	2.77	2.52	2.63	3.43	3.81	4.46	5.45
Capital Power's Alberta portfolio average realized power price ($ per MWh)	55	61	46	59	58	56	57	58

Factors impacting results for the fourth quarter of 2015

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 last year 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 the 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.

Factors impacting results for the previous quarters

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

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 acquired 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.

In the second quarter of 2014, the results for the Alberta commercial plants reflected seasonally low Alberta power prices, lower generation from the acquired Sundance PPA units, and lower generation at Genesee 3 caused by transmission constraints. However, the results for the Alberta contracted plants were positively impacted by lower rolling average pool prices which caused lower availability penalties on outages in the second quarter of 2014 compared with the same quarter in 2013. Capital Power recorded revenues of $20 million arising from the amendment of the Genesee Coal Mine Agreements. The Company announced a 7.9% increase in the annual dividend for holders of its common shares commencing with the third quarter 2014 quarterly dividend payment.

The first quarter of 2014 included the first full quarter of operations and results for Capital Power's Port Dover and Nanticoke wind facility. The Alberta commercial plants' results were impacted by lower pricing experienced in this quarter compared with the first quarter of 2013. The impact of lower pricing on the significantly hedged portfolio also reduced portfolio optimization results. Additionally, the Company experienced higher costs of emissions compliance. The Genesee 1 unit within the Alberta contracted plants category experienced a 10-day unplanned outage which dampened results. Depreciation and amortization expense was reduced from prior quarters due to the disposal of the North East U.S. assets.

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

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

	Three months ended							
	Dec 31 2015	**Sep 30 2015**	**Jun 30 2015**	**Mar 31 2015**	**Dec 31 2014**	**Sep 30 2014**	**Jun 30 2014**	**Mar 31 2014**
Share price ($/common share)								
High	20.21	22.42	25.58	27.12	28.14	28.71	26.49	25.81
Low	15.41	18.28	21.53	23.77	24.50	25.75	24.07	20.51
Close	17.77	18.88	21.54	24.51	26.00	26.75	26.37	25.72
Volume of shares traded (millions)	20.5	19.4	21.1	18.8	13.9	12.5	13.9	18.2

Outstanding share and partnership unit data

As at February 15, 2016, the Company had 96.194 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 February 15, 2016 were 99.902 million. The outstanding special limited voting share is held by EPCOR.

As at February 15, 2016, CPLP had 21.750 million general partnership units outstanding, 80.953 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

ADDITIONAL INFORMATION

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

Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(In millions of Canadian dollars)
Years ended December 31, 2015 and 2014

Management's responsibility for financial reporting

The preparation and presentation of the accompanying consolidated financial statements of Capital Power Corporation (the Company) are the responsibility of management and the consolidated financial statements have been approved by the Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with International Financial Reporting Standards. The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to February 18, 2016. Financial information presented elsewhere in this annual report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board of Directors.

The consolidated financial statements have been examined by KPMG LLP, the Company's external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with International Financial Reporting Standards. The independent auditors' report outlines the scope of their audit examination and states their opinion.

The Board of Directors, through the Audit Committee, is responsible for ensuring management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and annual report and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management. The Audit Committee is also responsible for reviewing and recommending the annual appointment of the external auditors and approving the annual external audit plan.

On behalf of management,

Brian Vaasjo
President and Chief Executive Officer

Bryan DeNeve
Senior Vice President, Finance and
Chief Financial Officer

February 18, 2016

CAPITAL POWER CORPORATION

Consolidated Financial Statements

Years ended December 31, 2015 and 2014

KPMG LLP
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Edmonton AB
T5J 3V8

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Capital Power Corporation

We have audited the accompanying consolidated financial statements of Capital Power Corporation, which comprise the consolidated statements of financial position as at December 31, 2015 and December 31, 2014, the consolidated statements of income, comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Capital Power Corporation as at December 31, 2015 and December 31, 2014, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards**.**

KPMG LLP

Chartered Professional Accountants
February 18, 2016
Edmonton, Canada

CAPITAL POWER CORPORATION
Consolidated Statements of Income
(In millions of Canadian dollars, except per share amounts)

Years ended December 31

	2015	2014
Revenues (note 4)	$ 1,251	$ 1,228
Energy purchases and fuel	(489)	(511)
Gross margin	762	717
Other raw materials and operating charges (note 5)	(96)	(83)
Staff costs and employee benefits expense (note 5)	(120)	(123)
Depreciation and amortization (note 5)	(215)	(189)
Other administrative expense (note 5)	(85)	(88)
Foreign exchange loss	(15)	(10)
Operating income	231	224
Finance expense (note 6)	(94)	(55)
Income from joint venture (note 33)	15	-
Income before tax	152	169
Income tax expense (note 7)	(66)	(119)
Net income	$ 86	$ 50
Attributable to:		
Non-controlling interests (note 32)	$ (4)	$ 4
Shareholders of the Company	$ 90	$ 46

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

Basic (note 8)	$ 0.70	$ 0.28
Diluted (note 8)	$ 0.70	$ 0.28

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Comprehensive Income
(In millions of Canadian dollars)

Years ended December 31

	2015	2014
Net income	$ 86	$ 50
Other comprehensive income (loss):		
Items that will not be reclassified subsequently to net income:		
Defined benefit plans:		
Actuarial gains (losses)[1]	4	(2)
Items that are or may be reclassified subsequently to net income:		
Cash flow hedges:		
Unrealized gains on derivative instruments [2]	73	59
Unrealized losses on derivative instruments – joint venture (note 33) [3]	(8)	(15)
Reclassification of gains on derivative instruments to income for the year [4]	(59)	(18)
Net investment in foreign subsidiaries:		
Unrealized gain [5]	34	16
Total items that are or may be reclassified subsequently to net income, net of tax	40	42
Total other comprehensive income, net of tax	44	40
Total comprehensive income	$ 130	$ 90
Attributable to:		
Non-controlling interests (note 32)	$ (2)	$ 14
Shareholders of the Company	$ 132	$ 76

[1] For the year ended December 31, 2015, net of income tax expense of $1. For the year ended December 31, 2014, net of income tax recovery of $1.

[2] For the year ended December 31, 2015, net of income tax expense of $28. For the year ended December 31, 2014, net of income tax expense of $14.

[3] For the year ended December 31, 2015, net of income tax recovery of $3. For the year ended December 31, 2014, net of income tax recovery of $5.

[4] For the year ended December 31, 2015, net of reclassification of income tax expense of $22. For the year ended December 31, 2014, net of reclassification of income tax expense of $4.

[5] For the years ended December 31, 2015 and December 31, 2014, net of income tax of nil.

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Financial Position
(In millions of Canadian dollars)

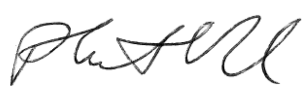
As at December 31

	2015	2014
Assets		
Current assets:		
Cash and cash equivalents (note 11)	$ 80	$ 71
Trade and other receivables (note 12)	190	185
Inventories (note 13)	99	104
Derivative financial instruments assets (note 14)	166	132
	535	492
Non-current assets:		
Other assets	24	28
Derivative financial instruments assets (note 14)	54	55
Finance lease receivables (note 15)	689	708
Other financial assets (note 16)	13	18
Deferred tax assets (note 17)	18	21
Equity-accounted investment (note 33)	10	22
Intangible assets (note 18)	341	350
Property, plant and equipment (note 19)	3,679	3,701
Goodwill (note 20)	30	25
Total assets	$ 5,393	$ 5,420

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board:

Donald Lowry
Director and Chairman of the Board



Philip Lachambre
Director and Chairman of the Audit Committee

CAPITAL POWER CORPORATION

Consolidated Statements of Financial Position
(In millions of Canadian dollars)

As at December 31

	2015	2014
Liabilities and equity		
Current liabilities:		
Trade and other payables (note 21)	$ 181	$ 185
Derivative financial instruments liabilities (note 14)	38	64
Loans and borrowings (note 22)	339	599
Deferred revenue and other liabilities	2	5
Provisions (note 23)	22	22
	582	875
Non-current liabilities:		
Derivative financial instruments liabilities (note 14)	15	10
Loans and borrowings (note 22)	1,276	987
Finance lease obligation (note 15)	21	-
Deferred revenue and other liabilities	97	98
Deferred tax liabilities (note 17)	376	249
Provisions (note 23)	210	198
	1,995	1,542
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 24)	2,744	2,391
Retained earnings (deficit)	(70)	25
Other reserves (note 25)	74	35
Retained earnings and other reserves	4	60
	2,748	2,451
Non-controlling interests (note 32)	68	552
Total equity	2,816	3,003
Total liabilities and equity	$ 5,393	$ 5,420

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Equity
(In millions of Canadian dollars)

	Share capital (note 24)	Cash flow hedges [1]	Cumulative translation reserve [1]	Defined benefit plan actuarial gains (losses)[1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests (note 32)	Total
Equity as at January 1, 2015	$ 2,391	$ 40	$ (1)	$ (13)	$ 9	$ 25	$ 2,451	$ 552	$ 3,003
Net income	-	-	-	-	-	90	90	(4)	86
Other comprehensive income:									
Defined benefit plan actuarial gains	-	-	-	5	-	-	5	-	5
Cash flow derivative hedge gains	-	101	-	-	-	-	101	-	101
Cash flow derivative hedge losses – joint venture	-	(11)	-	-	-	-	(11)	-	(11)
Reclassification of gains to income	-	(81)	-	-	-	-	(81)	-	(81)
Unrealized gain on foreign currency translation	-	-	34	-	-	-	34	-	34
Tax on items recognized directly in equity	-	(3)	-	(1)	-	-	(4)	-	(4)
Attributed to non-controlling interests	-	-	(2)	-	-	-	(2)	2	-
Other comprehensive income	$ -	$ 6	$ 32	$ 4	$ -	$ -	$ 42	$ 2	$ 44
Total comprehensive income (loss)	-	6	32	4	-	90	132	(2)	130
Issue of share capital	449	-	-	-	-	-	449	-	449
Deferred taxes on share issue costs	1	-	-	-	-	-	1	-	1
Distributions to non-controlling interests	-	-	-	-	-	-	-	(6)	(6)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	6	6
Change in non-controlling interests ownership	-	-	-	-	-	33	33	(482)	(449)
Tax on change in non-controlling interests ownership	-	(4)	-	-	-	(60)	(64)	-	(64)
Common share dividends (note 24)	-	-	-	-	-	(135)	(135)	-	(135)
Preferred share dividends (note 24)	-	-	-	-	-	(22)	(22)	-	(22)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Dividends reinvested	22	-	-	-	-	-	22	-	22
Common shares purchased	(121)	-	-	-	-	-	(121)	-	(121)
Share options exercised	2	-	-	-	-	-	2	-	2
Share-based payment	-	-	-	-	1	-	1	-	1
Equity as at December 31, 2015	$ 2,744	$ 42	$ 31	$ (9)	$ 10	$ (70)	$ 2,748	$ 68	$ 2,816

[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 consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Equity
(In millions of Canadian dollars)

	Share capital (note 24)	Cash flow hedges [1]	Cumulative translation reserve [1]	Defined benefit plan actuarial losses [1]	Employee benefits reserve	Retained earnings	Equity attributable to shareholders of the Company	Non-controlling interests (note 32)	Total
Equity as at January 1, 2014	$ 2,328	$ 21	$ (14)	$ (11)	$ 10	$ 83	$ 2,417	$ 587	$ 3,004
Net income	-	-	-	-	-	46	46	4	50
Other comprehensive income (loss):									
Defined benefit plan actuarial losses	-	-	-	(3)	-	-	(3)	-	(3)
Cash flow derivative hedge gains	-	73	-	-	-	-	73	-	73
Cash flow derivative hedge losses – joint venture	-	(20)	-	-	-	-	(20)	-	(20)
Reclassification of gains to income	-	(22)	-	-	-	-	(22)	-	(22)
Unrealized gain on foreign currency translation	-	-	16	-	-	-	16	-	16
Tax on items recognized directly in equity	-	(5)	-	1	-	-	(4)	-	(4)
Attributed to non-controlling interests	-	(7)	(3)	-	-	-	(10)	10	-
Other comprehensive income (loss)	$ -	$ 19	$ 13	$ (2)	$ -	$ -	$ 30	$ 10	$ 40
Total comprehensive income (loss)	-	19	13	(2)	-	46	76	14	90
Distributions to non-controlling interests	-	-	-	-	-	-	-	(25)	(25)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	5	5
Change in non-controlling interests ownership	-	-	-	-	-	29	29	(29)	-
Tax on change in non-controlling interests ownership	-	-	-	-	-	(2)	(2)	-	(2)
Common share dividends (note 24)	-	-	-	-	-	(108)	(108)	-	(108)
Preferred share dividends (note 24)	-	-	-	-	-	(22)	(22)	-	(22)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Dividends reinvested	37	-	-	-	-	-	37	-	37
Share options exercised	26	-	-	-	(2)	-	24	-	24
Share-based payment	-	-	-	-	1	-	1	-	1
Equity as at December 31, 2014	$ 2,391	$ 40	$ (1)	$ (13)	$ 9	$ 25	$ 2,451	$ 552	$ 3,003

[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 consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Cash Flows
(In millions of Canadian dollars)

Years ended December 31

	2015	2014
Cash flows from operating activities:		
Net income	$ 86	$ 50
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization (note 5)	215	189
Finance expense (note 6)	94	55
Fair value changes on commodity derivative instruments and emission credits held for trading	1	(36)
Unrealized foreign exchange loss	17	10
Income tax expense (note 7)	66	119
Other items	(17)	4
Change in fair value of derivative instruments reflected as cash settlement	8	17
Finance lease receivable collected	19	17
Interest paid [1]	(80)	(45)
Income taxes (paid) recovered [2]	(1)	10
Change in non-cash operating working capital (note 26)	11	1
Net cash flows from operating activities	419	391
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(140)	(220)
Business acquisition, net of acquired cash (note 9)	-	(18)
Other cash flows from investing activities	18	21
Change in non-cash investing working capital	(14)	(13)
Net cash flows used in investing activities	(136)	(230)
Cash flows used in financing activities:		
Proceeds from issue of loans and borrowings	220	17
Repayment of loans and borrowings	(267)	(65)
Issue costs on loans and borrowings	(1)	-
Proceeds on sale and leaseback of generating facility (note 19)	46	-
Proceeds from exercise of share options (note 24)	2	24
Common shares purchased (note 24)	(121)	-
Distributions paid to non-controlling interests (note 27)	(13)	(24)
Common share dividends paid (note 24)	(106)	(68)
Preferred share dividends paid (note 24)	(22)	(22)
Interest paid [1]	(9)	(39)
Income taxes paid [2]	(9)	(14)
Net cash flows used in financing activities	(280)	(191)
Foreign exchange gain on cash held in a foreign currency	6	1
Net increase (decrease) in cash and cash equivalents	9	(29)
Cash and cash equivalents, beginning of year	71	100
Cash and cash equivalents, end of year	$ 80	$ 71

[1] Total interest paid.
[2] Total income taxes paid.

See accompanying notes to the consolidated financial statements

1. Reporting entity:

Capital Power Corporation (the Company or Capital Power) builds, owns and operates power facilities and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities.

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

2. Significant accounting policies:

(a) Basis of presentation:

These consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS).

These consolidated financial statements 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 consolidated financial statements were approved and authorized for issue by the Board of Directors on February 18, 2016.

(b) Basis of consolidation:

These consolidated financial statements include the accounts of Capital Power and its subsidiaries. Subsidiaries are fully consolidated from the date of acquisition, being the date on which the Company obtains control, and continue to be consolidated until the date that such control ceases to exist.

The Company has a 100% interest in Capital Power L.P. (CPLP) (2014 – 82%). Based on an assessment of the relationship between Capital Power and CPLP as disclosed in note 32, Capital Power controls CPLP and therefore CPLP is treated as a subsidiary of Capital Power. As of April 2, 2015 EPCOR Utilities Inc. (EPCOR) reduced its ownership in CPLP to nil (December 31, 2014 -18%) and therefore no longer holds a non-controlling interest in CPLP as described in note 32.

Non-controlling interests in subsidiaries are identified separately from equity attributable to shareholders' of the Company. The non-controlling interests may be initially measured either at fair value or at the non-controlling interests' proportionate share of the fair value of the acquired business' identifiable net assets. The choice of measurement basis is made on an acquisition-by-acquisition basis. Subsequent to acquisition, the carrying amount of non-controlling interests is the amount of those interests at initial recognition plus the non-controlling interest's share of subsequent changes in equity. Total comprehensive income is attributed to non-controlling interests even if this results in the non-controlling interests having a deficit balance.

All significant intercompany balances and transactions have been eliminated on consolidation.

The financial statements of the subsidiaries are prepared for the same reporting period as Capital Power, using consistent accounting policies.

(c) Business combinations and goodwill:

Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of acquisition in exchange for control of the acquired business. Acquisition-related costs are recognized into net income as incurred. Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. When the excess is negative, a bargain purchase gain is recognized immediately into net income.

Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the date of acquisition. Where an acquisition involves consideration contingent on future events, any changes in the amount of consideration paid will be recognized into net income.

2. Significant accounting policies, continued:

(c) Business combinations and goodwill, continued

Business combinations, continued

The Company elects on a transaction-by-transaction basis whether to measure non-controlling interest at its fair value, or at its proportionate share of the recognized amount of the identifiable net assets, at the acquisition date. Transaction costs, other than those associated with the issue of debt or equity securities, that the Company incurs in connection with a business combination are expensed as incurred.

Goodwill

After initial recognition, goodwill is not amortized, but is measured at cost less any accumulated impairment losses. Goodwill is tested for impairment annually, or more frequently if events or changes in circumstances indicate that the carrying amount may be impaired, at the cash-generating unit (CGU) level. For the purpose of impairment testing, goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the Company's CGUs that are expected to benefit from the acquisition.

For further discussion on impairment of goodwill, refer to the accounting policy for impairment of non-financial assets (note 2(n)).

Where goodwill forms part of a CGU and part of the operation within that unit is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the CGU retained.

(d) Investments in joint arrangements:

Investments in joint operations

Capital Power has interests with other parties (the joint operators), whereby in each case the joint operators have a contractual arrangement that establishes the joint operators' rights to the assets and obligations for the liabilities of the arrangement and the joint operators' rights to the corresponding revenues and obligations for the corresponding expenses. These arrangements are considered to be joint operations.

In these situations Capital Power recognizes its share of the joint operations' assets and liabilities in accordance with those associated rights and obligations, along with its share of the revenues from the output of the joint operation along with its share of any expenses incurred. The accounting policies of these joint operations are aligned with the accounting policies of the Company.

Investments in joint ventures

The Company, along with two third parties (the partners), has an equal interest in a partnership established to develop, construct and operate a wind power project. By contractual agreement, each of the partners effectively has rights to the net assets of the arrangement and as a result the arrangement is considered to be a joint venture.

The Company's investment in this joint venture is accounted for under the equity method, and was recognized initially at cost and the carrying amount is increased or decreased to recognize the Company's share of the joint venture's net income or loss after the date of acquisition. Distributions received from the joint venture reduce the carrying amount of the investment. The accounting policies of the joint venture are aligned with the accounting policies of the Company.

(e) Foreign currency translation:

Transactions in foreign currencies are translated to the respective functional currencies of the Company, or the subsidiary concerned, at exchange rates in effect at the transaction date. At each reporting date monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect at the date of the statement of financial position. The translation for other non-monetary assets is not updated from historical exchange rates unless they are carried at fair value. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting foreign exchange gains and losses are included in net income.

2. Significant accounting policies, continued:

(e) Foreign currency translation, continued

On consolidation, the assets and liabilities of U.S. operations that have a functional currency that is different from the Company's functional currency of Canadian dollars are translated into Canadian dollars at the exchange rates in effect at the date of the statement of financial position. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in accumulated other comprehensive income as part of translation gains and losses.

(f) Revenue recognition:

Energy sales

Revenues from the sales of electricity and natural gas are recognized when the risks and rewards of ownership pass to the buyer, collection is reasonably assured and the price is reasonably determinable. This occurs upon delivery or availability for delivery under take-or-pay contracts. These revenues include an estimate of the value of electricity and natural gas consumed by customers, but billed subsequent to reporting period-end.

The Company recognizes revenues from certain of its generation units operating under power purchase agreements (PPAs) as described in note 2(g). PPAs are a form of long-term sales arrangement between the owner of a generation unit and the contracted purchaser under the PPA.

Revenues from the sale of other goods are recognized when the products have been delivered.

Service revenues

Revenues from operating and management services are recognized when the service has been performed or delivered.

Derivative instruments

Revenues also include realized and unrealized gains and losses from derivatives used in the risk management of the Company's generation activities related to commodity prices and foreign currency risk, and from the Company's proprietary trading activities. Realized gains and losses are recognized when the settlement of trading positions occurs and unrealized gains and losses are recorded as revenues based on the related changes in the fair value of the financial instrument at the end of each reporting period.

Deferred revenues

Payments received on one of the Company's operating leases may be in excess of accounting lease revenues. In such cases, the Company records deferred revenue on its consolidated statement of financial position.

The Company records any gains resulting from sale and leaseback transactions as deferred revenue on its consolidated statement of financial position and amortizes the gain to depreciation and amortization on a straight-line basis over the lease term.

Monetary contributions received from third parties used to provide the Company with ongoing access to a supply of goods or services are measured at fair value of the cash received and are initially recorded as deferred revenue. Revenue is recognized as the service is performed, or if an ongoing service is performed as part of an agreement, over the lesser of the life of the agreement and the life of the asset.

(g) Leases or arrangements containing a lease:

The Company has entered into PPAs to sell power at predetermined prices. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the Company's property, plant and equipment in return for payment. If the PPAs are determined to contain a lease, the arrangements may be classified as either finance or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property from the Company are classified as finance leases. PPAs that do not transfer substantially all of the benefits and risks of ownership of property, plant and equipment are classified as either operating leases or executory contracts.

2. Significant accounting policies, continued:

(g) Leases or arrangements containing a lease, continued

For those PPAs determined to be finance leases with the Company as the lessor, finance income is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is composed of minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying amount of the leased property. Unearned finance income is deferred and recognized into net income over the lease term.

Payments received under PPAs classified as finance leases are segmented into those for the lease and those for other elements of the PPA on the basis of their relative fair values.

For those PPAs determined to be operating leases with the Company as the lessor, revenue is recognized on a straight-line basis unless another method better represents the earnings process.

Where the Company has purchased goods or services as a lessee, and the lease has been determined to be an operating lease, rental payments are expensed as incurred over the life of the lease. Contractual arrangements the Company has entered into as a lessee that transfer substantially all of the risks and rewards of ownership to the Company are considered finance leases. The leased asset and lease obligation are recognized at the lower of fair value or the present value of the minimum lease payments. Lease payments are recorded as interest expense and a reduction of the lease liability. Interest expense is recognized using the effective interest method. The leased asset is depreciated over the shorter of the estimated useful life of the asset and the lease term.

(h) Non-derivative financial instruments:

Financial assets are identified and classified as either available for sale, held at fair value through income or loss or loans and receivables. Financial liabilities are classified as either held at fair value through income or loss or other financial liabilities.

Financial instruments at fair value through income or loss

A financial asset is classified as held at fair value through income or loss if it is classified as held for trading or is designated as such upon initial recognition. The Company may designate financial instruments as held at fair value through income or loss when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis.

Upon initial recognition transaction costs are recognized into net income as incurred. Financial assets classified as held at fair value through income or loss are measured at fair value with the changes in fair value reported in net income. Fair values are determined in the manner described in note 3.

Gains or losses realized on de-recognition of investments held at fair value through income or loss are recognized into net income.

Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. The Company's current loans and receivables comprise its cash and cash equivalents and trade and other receivables. Non-current loans and other long-term receivables comprise promissory notes receivable and amounts due from customers more than one year from the date of the statement of financial position which will be repaid between 2016 and 2020.

These assets are recognized initially at fair value plus any directly attributable transaction costs. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses as described in note 2(o). The effective interest method calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

2. Significant accounting policies, continued:

(h) Non-derivative financial instruments, continued

Other financial liabilities

The Company's loans and borrowings, finance lease obligation and trade and other payables are recognized on the date at which the Company becomes a party to the contractual arrangement. Liabilities are derecognized when the contractual obligations are discharged or cancelled or expire.

Liabilities are recognized initially at fair value plus any directly attributable transaction costs, such as debenture discounts, premiums and issue expenses. Subsequently these liabilities are measured at amortized cost using the effective interest rate method.

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to set-off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company participates in a tax-equity structure with a project investor which financed the construction of the Macho Springs project (Macho Springs). This tax-equity structure is used in the U.S. to enable access to U.S income tax benefits such as investment tax credits (ITCs), cash grants, production tax credits (PTCs) and accelerated tax depreciation. In return for purchasing an equity stake in Macho Springs, the project investor receives substantially all earnings, tax benefits and cash flows from Macho Springs until it has yielded an agreed upon target rate of return to the project investor. Immediately thereafter, the structure "flips" such that the Company receives the majority of earnings, tax benefits and cash flows from Macho Springs. The date of the "flip" is dependent on the performance of the project. In accordance with the substance of the contractual agreement, the amounts paid by the project investor for their equity stake are classified as loans and borrowings on the consolidated statement of financial position until the "flip" date. Subsequent to the "flip" date, the project investor's equity investment will be accounted for as a non-controlling interest. At all times, both before and after the "flip", the Company retains control over Macho Springs.

(i) Derivative instruments and hedging activities:

To reduce its exposure to movements in energy commodity prices, interest rate changes, and foreign currency exchange rates, the Company uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, and option contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency.

All derivative instruments, including embedded derivatives, are recorded at fair value on the statement of financial position as derivative financial instruments assets or derivative financial instruments liabilities except for embedded derivative instruments that are clearly and closely related to their host contract and the combined instrument is not measured at fair value. Any contract to buy or sell a non-financial item is not treated as a non-financial derivative if that contract was entered into and continues to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements. The Company accounts separately for any embedded derivatives in any hybrid instruments issued or acquired. The Company does not account for foreign currency derivatives embedded in non-financial instrument host contracts when the currency that is commonly used in contracts to purchase or sell non-financial items in the economic environment is that currency in which the transaction takes place.

2. Significant accounting policies, continued:

(i) Derivative instruments and hedging activities, continued

All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used. If hedge accounting requirements are met, realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel and realized gains and losses on foreign exchange derivatives are recorded in revenues or foreign exchange gains and losses, as appropriate, while unrealized gains and losses are recorded in other comprehensive income. If hedge accounting requirements are not met, unrealized and realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel as appropriate, unrealized and realized gains and losses on financial foreign exchange derivatives are recorded in revenues or foreign exchange gains and losses and such gains and losses on financial interest rate derivatives are recorded in finance expense.

Commodity derivative instruments

The Company uses financial contracts-for-differences (or fixed-for-floating swaps) to hedge the Company's exposure to fluctuations in electricity prices. Under these instruments, the Company agrees to exchange, with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified timeframe.

The Company uses non-financial forward delivery derivatives to manage the Company's exposure to fluctuations in natural gas prices related to its natural gas customer contracts and obligations arising from its natural gas fired generation facilities. Under these instruments, the Company agrees to sell or purchase natural gas at a fixed price for delivery of a pre-determined quantity under a specified timeframe.

The Company may use non-financial or financial commodity derivative instruments with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities. Such transactions are recognized on a net basis in the Company's revenues.

Foreign exchange derivative instruments

Foreign exchange forward contracts are used by the Company to manage foreign exchange exposures, consisting mainly of U.S. dollar exposures, resulting from anticipated transactions denominated in foreign currencies. For transactions involving the development or acquisition of property, plant and equipment, when the real or anticipated transaction subsequently results in the recognition of a financial asset, the associated gains or losses on derivative instruments are included in the initial carrying amount of the asset acquired in the same period or periods in which the asset is acquired or constructed.

Interest rate derivative instruments

The Company uses cross currency interest rate swaps to manage the foreign currency exchange risk on U.S. dollar denominated loans and borrowings. Under these instruments, the Company and the counterparties exchange principal amounts at initiation of the transaction, whereby the Company pays the counterparties U.S. dollar principal amounts and the counterparties pay the Company Canadian dollar principal amounts. Over the terms of these instruments, the Company makes fixed rate interest payments in Canadian dollars on the initial principal to the counterparties while the counterparties make fixed rate interest payments in U.S. dollars to the Company.

The Company uses fixed for floating interest rate swaps to optimize its mix of loans and borrowings at fixed interest rates and those at floating interest rates. Under these instruments, the Company agrees to pay the counterparties floating rate interest payments in exchange for the counterparties paying the Company fixed rate interest payments on the notional amount of loans and borrowings.

Hedge accounting

The Company may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Company documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retrospective and prospective basis.

2. Significant accounting policies, continued:

(i) Derivative instruments and hedging activities, continued

Hedge accounting, continued

The Company uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in commodity prices and to reduce exposure to currency risk pertaining to the variability of cash flows on U.S. dollar loans and borrowings. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while the ineffective portion is recognized in energy revenues or energy purchases or fuel, as appropriate. The amounts recognized in other comprehensive income as cash flow hedging gains/losses are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income when it becomes probable that the hedged items will not occur. The Company has not designated any fair value hedges at the date of the statement of financial position.

A hedging relationship is discontinued if the hedge relationship ceases to be effective, if the hedged item is an anticipated transaction and it is probable that the transaction will not occur by the end of the originally specified time period, if the Company terminates its designation of the hedging relationship, or if either the hedged or hedging instrument ceases to exist as a result of its maturity, expiry, sale, termination or cancellation and is not replaced as part of the Company’s hedging strategy.

If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive income as part of cash flow hedging gains/losses and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the same period as the corresponding gains or losses on the hedged item. When it is no longer probable that an anticipated transaction will occur within the originally determined period and the associated cash flow hedge has been discontinued, any remaining gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the period.

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized in net income. The fair value of derivative financial instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter quotations by reference to bid or asking price, as appropriate, in active markets. In illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management’s best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. 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.

(j) Property, plant and equipment:

Property, plant and equipment are recorded at cost, net of accumulated depreciation and/or accumulated impairment losses, if any.

Capitalization

Cost includes contracted services, materials, borrowing costs on qualifying assets, direct labour, directly attributable overhead costs, development costs associated with specific property, plant and equipment and asset retirement costs. When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

2. Significant accounting policies, continued:

(j) Property, plant and equipment, continued

Capitalization, continued

The cost of replacing a part of an item of property, plant and equipment is capitalized if it is probable that the future economic benefits of the part will flow to the Company and that its cost can be measured reliably. The carrying amount of the replaced part is derecognized. Costs of day to day repairs and maintenance costs are recognized into net income as incurred.

Depreciation

Depreciation is charged to net income on a straight-line basis over the estimated useful lives of each major component of an item of property, plant and equipment, since this most closely reflects the expected pattern of consumption of the asset. Major components of property, plant and equipment are depreciated separately over their respective useful lives. Land and construction work in progress are not depreciated. The estimated useful lives for major components of generation facilities and equipment range from 1 to 53 years. The estimated useful lives, residual values and methods of depreciation are reviewed annually, and adjusted prospectively if appropriate.

Gains and losses on the disposal or retirement of an item of property, plant and equipment are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. Gains or losses on disposals are recognized on their own line within the consolidated statements of income while losses on retirements are recognized within depreciation and amortization.

(k) Intangible assets:

Capitalization

Intangible assets with definite lives are recorded at cost, net of accumulated amortization and/or accumulated impairment losses, if any. Intangible assets with definite lives are amortized over the related assets useful lives, as described below. Refer to note 18 for additional discussion on intangible assets.

The only indefinite life intangible assets recorded by the Company are purchased emission credits held for compliance purposes.

Amortization

Amortization is charged to net income on a straight-line basis to write-off the cost less the estimated residual value over the estimated remaining term of the agreement or in line with the life of the related generating facility to which it relates. Software work in progress is not amortized as the software is not available for use. Land lease rights are amortized when the related wind power assets are constructed and commissioned for service over the lives of the related wind power assets or the term of the lease, whichever is shorter. Coal supply access rights are amortized over the life of the coal supply agreement related to the Keephills 3 facility. The Company's purchased emission credits held for compliance purposes are not amortized, but are expensed as the associated benefits are realized.

The periods over which intangible assets are amortized are as follows:

Alberta PPA	12 years
Contract rights	7 to 51 years
Software	1 to 10 years

Estimated useful lives, methods of amortization and residual values are reviewed annually, and adjusted prospectively if required.

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount of the asset, and are recognized into net income as gains or losses on disposals.

2. Significant accounting policies, continued:

(l) Development costs:

Development costs related to an acquisition or construction project are capitalized only if they can be measured reliably, future economic benefits are probable, and the Company intends to and has sufficient resources to complete development and to use or sell the asset. Other development costs not meeting these criteria are recognized in income or loss as incurred. Capitalized development costs are measured at cost less accumulated amortization and accumulated impairment losses.

(m) Capitalized borrowing costs:

The Company capitalizes interest during construction on its property, plant and equipment and intangible assets to reflect the costs of borrowing on its construction activities. Where project specific debt is not used to finance construction, interest is applied during construction using the weighted average cost of debt incurred on the Company's external borrowings used to finance qualifying assets. Interest is only capitalized on assets which necessarily take a significant amount of time to get ready for their intended use.

(n) Impairment of non-financial assets:

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into a CGU, which is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

The Company reviews the recoverability of non-financial assets subject to depreciation or amortization (property, plant and equipment and definite life intangible assets) when events or changes in circumstances may indicate or cause the asset's carrying amount to exceed its recoverable amount. The Company reviews the recoverability of goodwill and indefinite life intangibles on an annual basis, or more frequently if events or changes in circumstances indicate that the carrying amount may be impaired. The asset's recoverable amount is the higher of its fair value less costs to sell and its value in use. The value in use is the present value of expected future cash flows discounted using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. Fair value less costs to sell is determined using estimated market values utilizing actual market transactions, if available. When actual market transactions are not available, a valuation model is used.

The Company's corporate assets, such as its computer networks and infrastructure, do not generate separate cash inflows. If there is an indication that a corporate asset may be impaired, then the recoverable amount is determined for the CGU to which the corporate asset belongs.

Any impairment loss is recorded in net income in the period when it is determined that the carrying amount of the asset may not be recoverable. The impairment loss is recorded as the excess of the carrying amount of the asset over its recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs, and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

At the end of each reporting period the Company makes an assessment as to whether there is any indication that previously incurred impairment losses no longer exist. If such an indication exists, the Company estimates the asset's recoverable amount. Any reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount or the carrying amount that would have been determined, after depreciation or amortization, had the original impairment loss not been recognized.

Any reversal is recognized into net income for the period. An impairment loss in respect of goodwill is not reversed.

2. Significant accounting policies, continued:

(o) Impairment of financial assets:

Financial assets, other than those classified as held at fair value through income or loss, are assessed for indicators of impairment at the end of each reporting period. An impairment loss is recorded for investments recorded at cost where it is identified that there is objective evidence that one or more events has occurred after the initial recognition of the asset, that has had a negative impact on the estimated future cash flows of the asset that can be reliably estimated.

For listed and unlisted equity investments classified as available for sale, a significant or prolonged decline in the fair value of the investment below its cost is considered to be objective evidence of impairment.

For certain categories of financial assets, such as trade receivables, assets that are assessed not to be impaired individually are in addition assessed for impairment on a collective basis. Objective evidence of impairment includes the Company's past experience of collecting payments, as well as observable changes in national or local economic conditions.

For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the asset's original effective interest rate. Any impairment loss is recognized in net income. If, in a subsequent reporting period, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognized, the previously recognized impairment loss is adjusted through net income.

(p) Income taxes:

Income tax expense is comprised of current and deferred tax. Current and deferred tax is recognized in net income or loss except to the extent that it relates to a business combination, or items recognized directly in equity, other comprehensive income, or in loans and borrowings.

Current income taxes

Current income taxes comprise the expected tax payable or receivable on the taxable income or loss for the year and any adjustment to the tax payable or receivable in respect of previous years. The amount of current income tax payable or receivable is the best estimate of the tax amount expected to be paid or received that reflects uncertainty related to income taxes, if any. It is measured using tax rates enacted or substantively enacted at the reporting date. Current income taxes also include any tax arising from dividends. Current income tax assets and liabilities are only offset if certain criteria are met.

Deferred income taxes

Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the respective amounts used for taxation purposes. Deferred income taxes are not recognized for:

- Temporary differences from the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither the taxable nor the accounting income;
- Temporary differences related to investments in subsidiaries, associates and joint arrangements to the extent that the Company is able to control the timing of the reversal of the temporary differences and it is probable that they will not reverse in the foreseeable future; and
- Temporary differences arising on the initial recognition of goodwill.

2. Significant accounting policies, continued:

(p) Income taxes, continued

Deferred income tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable income will be available against which they can be used. Future taxable income is determined based on the Company's cash flow projections, which include estimates described in note 3. Deferred income tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable the related tax benefit will be realized; such reductions are reversed when the probability of future taxable income improves. Unrecognized deferred income tax assets are reassessed at each reporting date and recognized to the extent that it has become probable that future taxable income will be available against which they can be used.

Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted at the reporting date. The measurement of deferred income taxes reflects the tax consequences that would follow from the manner in which the Company expects, at the reporting date, to recover or settle the carrying amount of its assets and liabilities. Deferred income tax assets and liabilities are offset only if certain criteria are met.

The Company records deferred income tax provisions related to its economic interest in CPLP and records current income tax pursuant to the contractual provision in the CPLP Limited Partnership Agreement.

(q) Inventories:

Parts and other consumables and coal, principally all of which are consumed by the Company in the provision of its goods and services, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of any assembled inventory includes direct labour, materials and directly attributable overhead. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Emission credits held for trading are carried at fair value as estimated by quoted market prices available as of the valuation date. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstance.

(r) Cash and cash equivalents:

Cash and cash equivalents include cash or highly liquid investment-grade short-term investments with original terms to maturity of three months or less, and are measured at amortized cost using the effective interest method.

(s) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. The obligation is discounted using a discount rate that reflects current market assessments of the time value of money and the risks specific to the obligation for which the estimates of future cash flows have not been adjusted. The change in discount rate due to the passage of time is recognized as a finance expense, and is recorded over the estimated time period until settlement of the obligation. Provisions are reviewed and adjusted, when required, to reflect the current best estimate at the end of each reporting period.

The Company recognizes decommissioning provisions in the period in which a legal or constructive obligation is incurred. A corresponding decommissioning cost is added to the carrying amount of the associated property, plant and equipment, and it is depreciated over the estimated useful life of the asset. Unwinding of the discount rate on the decommissioning provisions is recorded in finance expense over the estimated useful life of the asset.

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on the assets associated with that contract.

2. Significant accounting policies, continued:

(t) Share-based payments:

The Company operates an equity-settled, share-based compensation plan where each stock option converts into one common share. The fair value of the employee services received in exchange for the grant of the options is recognized as a compensation expense within staff costs and credited to the employee benefits reserve. The employee benefits reserve is reduced as the options are exercised and the amount initially recorded as a credit in employee benefits reserve is reclassified to share capital. The total amount to be expensed over the vesting period is determined by reference to the fair value of the options granted.

The Company determines the fair value of stock options using a binomial option pricing model at the date of grant. Measurement inputs include the share price on the measurement date, the exercise price of the instrument, expected volatility, expected term of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

The Company has incorporated an estimated forfeiture rate for stock options that will not vest into its determination of share-based compensation for each period.

The Company also operates share-based compensation plans for certain senior employees under a Performance Share Unit (PSU) Plan and a Restricted Share Unit (RSU) Plan. Share-based compensation for directors operates under a Directors' Deferred Share Unit (DSU) Plan. The fair values of the amounts payable to employees/directors in respect of the PSU Plan, RSU Plan and the DSU Plan, which are settled in cash, are recognized as expenses with corresponding increases in liabilities, over the period that the employees/directors unconditionally become entitled to payments. The grant date fair values are determined using a binomial lattice valuation based on a five day weighted average price of the Company's shares immediately prior to the grant, adjusted for estimated forfeitures and discounted using the risk-free interest rate. The liability is re-measured to fair value at each reporting date and at the settlement date. Any changes in the fair value of the liability are recognized in income or loss.

(u) Earnings per share:

Basic earnings per share is calculated by dividing income available to common shareholders by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated on the treasury stock method, by dividing income available to common shareholders, adjusted for the effects of dilutive securities, by the weighted average number of common shares outstanding during the period and all additional common shares that would have been outstanding had all potential dilutive common shares been issued.

(v) Future accounting changes:

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 to IAS 1 are effective for annual periods beginning on or after January 1, 2016. Early application is permitted.

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 are effective for annual periods beginning on or after January 1, 2016. Early application is permitted.

IAS 7 – Statement of Cash Flows (Amendment) – The objective of the amendment issued is to improve disclosures of changes in financing liabilities to allow users of the financial statements to evaluate changes in liabilities arising from financing activities. The amendments to IAS 7 are effective for annual periods beginning on or after January 1, 2017.

2. Significant accounting policies, continued:

(v) Future accounting changes, continued

IFRS 15 – Revenue from Contracts with Customers – IFRS 15 is a single and comprehensive framework for revenue recognition that replaces previous revenue standards. IFRS 15 is effective for annual periods beginning on or after January 1, 2018 and is to be applied retrospectively.

IFRS 9 – Financial Instruments – IFRS 9 addresses the classification and measurement requirements of financial assets and liabilities and is intended to improve transparency in the disclosure of expected credit losses and is intended to improve the overall usefulness of financial statements for users by revising the current hedge accounting requirements. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 and is to be applied retrospectively. Earlier application is permitted.

IFRS 16 – Leases – The new standard which replaces IAS 17 – Leases addresses the recognition, measurement, presentation and disclosure of leases. IFRS 16 also provides a new approach to lessee accounting, requiring lessees to recognize assets and liabilities for all leases, which will require the Company to recognize a leased asset and leased obligation with respect to its lease arrangements for office space. IFRS 16 is effective for annual periods beginning on or after January 1, 2019. Early application is permitted if IFRS 15 – Revenue from Contracts with Customers has also been applied.

Management is currently assessing the impact of the above future accounting changes on the Company's consolidated financial statements.

3. Use of judgments and estimates:

The preparation of the Company's consolidated financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses in the consolidated financial statements and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. The Company reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgment in making these estimates and assumptions.

Critical judgments in applying accounting policies

The main judgments that were used in preparing the Company's consolidated financial statements relate to:

Non-financial assets

The determination of CGUs was based on management's judgment, giving consideration to geographic proximity and shared risk exposure and risk management.

Identifying events or changes in circumstances that may indicate or cause an asset's carrying amount to exceed its recoverable amount requires judgment in assessing what events or circumstances would have such an impact.

Classification of arrangements which contain a lease

As noted in note 2(g), the Company has exercised judgment in determining whether the risks and rewards of its generation assets which are subject to a PPA are transferred to the contracted purchaser under the PPA, in determining whether a lease exists and if so, whether the lease should be treated as a finance or operating lease. Details of those PPAs which contain either finance or operating leases are provided in note 15.

Consolidation of subsidiaries that are less than wholly owned

The Company has exercised judgment in determining certain subsidiaries are controlled by the Company even though the subsidiaries are less than wholly owned as described in note 32.

Classification of joint arrangements structured through a separate vehicle

The Company has exercised judgment in determining the classification of joint arrangements structured through separate vehicles as described in note 33.

3. Use of judgments and estimates, continued:

Key sources of estimation uncertainty

The main sources of estimation uncertainty in preparing the Company's consolidated financial statements relate to:

Measurement of fair values

A number of the Company's accounting policies and disclosures require the measurement of fair values, for both financial and non-financial assets and liabilities. Fair value represents the Company's estimate of the price that could be agreed on 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. 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 following levels were established for each input:

- Level 1: Fair value is based on quoted prices (unadjusted) in active markets for identical instruments. Assets or liabilities classified in Level 1 include highly liquid short-term investments, and traded commodities obtained from active exchanges such as the New York Mercantile Exchange (NYMEX) whereby the Company can obtain quoted prices for identically traded commodities.
- Level 2: Fair value is based on other than unadjusted quoted prices included in Level 1, which are either directly or indirectly observable at the reporting date. Level 2 includes those assets or liabilities that are valued using commonly used valuation techniques, such as a discounted cash flow model or the Black-Scholes option pricing model. Valuation models use inputs such as quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active but observable, and other observable inputs that are principally derived from or corroborated by observable market data for substantially the full term of the instrument.
- Level 3: Fair value is based on unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the instrument. Level 3 includes assets or liabilities that are also valued using commonly used valuation techniques described in Level 2. However, some inputs used in the models may not be based on observable market data, but rather are based on the Company's best estimate from the perspective of a market participant.

The fair value measurement of an asset or liability is included in only one of the three levels, 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. As at December 31, 2015 and 2014, the Company did not classify any financial instruments in Level 3 of the hierarchy.

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 years ended December 31, 2015 and 2014.

Further information about the significant assumptions made in measuring fair values is included in the following notes:

- Note 10 – Impairment testing;
- Note 13 – Inventories - emissions credits;
- Notes 14 and 29 – Financial instruments;
- Note 23 – Decommissioning and other provisions; and
- Note 28 – Share-based payments.

Depreciation and amortization

Depreciation and amortization allocate the cost of assets and their components over their estimated useful lives on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of the life characteristics of common assets.

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

3. Use of judgments and estimates, continued:

Key sources of estimation uncertainty, continued

Income taxes

Income taxes are determined based on estimates of the Company’s current income taxes and estimates of deferred income taxes resulting from temporary tax differences. Deferred income tax assets are assessed to determine the likelihood that they will be realized from future taxable income. Details of tax losses expected to be utilized and the basis of utilization are provided in note 17.

Revenue recognition

As noted in note 2(f), estimates of the value of electricity and natural gas consumed by customers but not billed until after the reporting period-end are based on contracted prices and volume data provided by the parties responsible for delivering the commodity.

Actual results may differ from these estimates. Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

4. Revenues:

Capital Power is a party to various agreements with Prairie Mines & Minerals Royalty Ltd. (PMRL) in relation to the operations of the Genesee Coal Mine (Genesee Coal Mine Agreements). Pursuant to the Genesee Coal Mine Agreements, PMRL operates the Genesee Coal Mine. In connection with the 2014 acquisition by Westmoreland Coal Company (Westmoreland) of PMRL and the 2014 acquisition by Altius Minerals Corporation (Altius) of the royalty assets of PMRL, the Genesee Coal Mine Agreements and certain related agreements were, among other things, amended to: (a) confirm the acquisitions by Westmoreland and Altius; (b) provide for certain amendments to the Genesee Coal Mine Agreements; and (c) provide for a payment to Capital Power of $20 million upon completion of the acquisitions, which was received and recorded within revenues in 2014.

5. Expenses:

Year ended December 31	2015	2014
Included in other raw materials and operating charges		
Settlement of claim with turbine supplier	$ -	$ (8)
Included in staff costs and employee benefits expense		
Share-based (recoveries) payments (note 28)	(1)	8
Post-employment defined contribution plan expense	8	8
Post-employment defined benefit plan expense	4	4
Included in depreciation and amortization		
Depreciation of property, plant and equipment (note 19)	186	155
Amortization of intangible assets (note 18)	24	21
Losses on retirement of property, plant and equipment	2	3
Other	3	10
	215	189
Included in other administrative expenses		
Operating lease payments	8	8

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

6. Finance expense:

Year ended December 31	2015	2014
Interest expense		
Interest on loans and borrowings	$ 89	$ 84
Capitalized interest	(9)	(39)
Total interest expense	80	45
Other finance expense		
Loss (gain) on interest rate non-hedges (note 14)	2	(2)
Charge on early debt extinguishment	1	2
Unwinding of discount on decommissioning provisions (note 23)	4	3
Other	7	7
Finance expense	$ 94	$ 55

7. Income tax expense:

Year ended December 31	2015	2014
Current income tax		
Current income tax expense	$ 10	$ 11
Deferred income tax		
Origination and reversal of temporary differences	37	26
Change in statutory tax rate	19	-
Adjustments for prior periods	1	(1)
Recognition of previously unrecognized tax benefits	(6)	-
Write-downs of deferred tax assets	5	83
Total deferred income tax expense	56	108
Income tax expense	$ 66	$ 119

Reconciliation of effective income tax rate

Year ended December 31	2015	2014
Income before tax	$ 152	$ 169
Income tax at the statutory rate of 26.0%[1] (2014 - 25.0%)	40	42
Increase (decrease) resulting from:		
Amounts attributable to non-controlling interests	3	(4)
Change in unrecognized tax benefits	(1)	83
Non-deductible (taxable) amounts	1	(1)
Adjustments for prior periods	1	(1)
Statutory and other rate differences	20	(1)
Other	2	1
Income tax expense	$ 66	$ 119

[1] The statutory rate increased to 27.0% from 25.0% on July 1, 2015 due to legislative changes. This increase resulted in $19 million of deferred income tax expense, which is included in the statutory and other rate differences line above.

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

8. Earnings per share:

Basic earnings per share

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

Year ended December 31	2015	2014
Income for the period attributable to shareholders of the Company	$ 90	$ 46
Preferred share dividends of the Company [1]	(23)	(23)
Earnings used in the calculation of basic earnings per share	$ 67	$ 23

[1] Includes preferred share dividends declared for the years ended December 31, 2015 and 2014 respectively and related taxes.

Year ended December 31	2015	2014
Weighted average number of common shares used in the calculation of basic earnings per share	96,393,165	82,309,777

Diluted earnings per share

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

Year ended December 31	2015	2014
Earnings used in the calculation of basic earnings per share	$ 67	$ 23
Effect of exchangeable limited partnership units issued to EPCOR for common shares [2]	-	-
Earnings used in the calculation of diluted earnings per share	$ 67	$ 23

[2] The exchangeable limited partnership units issued to EPCOR were exchangeable for common shares of Capital Power on a one-for-one basis. On April 2, 2015, EPCOR exchanged all of its outstanding exchangeable limited partnership units for common shares of Capital Power. As such, the units exchanged were included in the calculation of the Company's basic earnings per share for the year ended December 31, 2015. For the year ended December 31, 2014, the potential exchange of such units for common shares of the Company was not included in the calculation of diluted loss per share as it was anti-dilutive.

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

Year ended December 31	2015	2014
Weighted average number of common shares used in the calculation of basic earnings per share	96,393,165	82,309,777
Effect of dilutive share purchase options [3]	-	233,777
Weighted average number of common shares used in the calculation of diluted earnings per share	96,393,165	82,543,554

[3] For the year ended December 31, 2015, the average market price of the Company's common shares was below the exercise price of all granted share purchase options described in note 28 and as a result none of the share purchase options had a dilutive effect on earnings per share. For the year ended December 31, 2014, the average market price of the Company's common shares exceeded the exercise price of all granted share purchase options described in note 28, but had a neutral effect on earnings per share.

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

9. Business combination:

The purchase price allocation of the Company's 2014 acquisition of Element Power U.S. LLC (Element) was finalized during 2015. The adjustments from the amounts recorded and disclosed at December 31, 2014 resulted from the receipt of final information related to balances as of the acquisition date, and minor changes in assumptions related to the replacement cost of property, plant and equipment. The adjustments were as follows:

	December 31, 2014	Adjustments	December 31, 2015
Cash	$ 3	$ -	$ 3
Other assets	3	-	3
Intangibles	36	-	36
Property, plant and equipment	103	(7)	96
Loans and borrowings	(76)	4	(72)
Provisions	(3)	-	(3)
Deferred tax liabilities	(29)	3	(26)
Fair value of net assets acquired	$ 37	$ -	$ 37

10. Impairment testing:

Property, plant and equipment and definite life intangible assets

On November 22, 2015, the Alberta Government (the Government) announced its Climate Leadership Plan (CLP). The key elements of the CLP that impact Capital Power are as follows:

- Coal emissions in Alberta are proposed to be phased out by 2030. This would mean a significant reduction in the economic lives of Capital Power's coal plants. The Government also announced it would not unnecessarily strand capital and clarified that compensation for plant owners will be important for maintaining investor confidence. However, it is highly uncertain what level of compensation will be provided, how it will be determined or how and when it will be paid.
- The CLP proposes a Carbon Competitiveness Regulation (CCR), which stipulates a carbon price to be borne by producers of CO_2 emissions. The carbon price starts at $20 per tonne ($/t) in January 2017 and rises to $30/t in January 2018, escalating thereafter, subject to further adjustments if the per tonne amount is inconsistent with peer regimes. The CCR will replace the existing Specified Gas Emitters Regulation (SGER) starting in 2018. Emission allowances for power generation units are expected to be based on "good as best gas" standards. Under the CCR, the carbon price can be settled either through payment of the $30/t levy to the Government or through procurement of equivalent CO_2 offsets. Capital Power's existing CO_2 offsets inventory, acquired for SGER compliance prior to the CLP announcement, is expected to be used to settle carbon costs through to 2018.
- The province is expected to move to more renewable sources of generation, including wind and solar to replace up to two-thirds of retiring coal plants.

There are numerous uncertainties associated with the CLP. Most significantly, it represents a proposed framework and has not been substantively enacted in legislation and therefore the final legal form and substance of the CLP is unknown. Accordingly, the CLP is not in itself a triggering event for purposes of assessing potential asset impairment. However, the uncertainties created by the CLP 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 CGUs (together referred to as the Alberta CGUs) were tested for impairment during the fourth quarter of 2015. The Company determined that no other CGUs were affected by the triggering event, since they operate in geographic regions that are not directly impacted by the events in Alberta.

The carrying amount of the Alberta Commercial CGU was within the range of its estimated recoverable amount and as such, no impairment was required. The carrying amount of the Alberta Contracted CGU was below the range of its estimated recoverable amount and as such, no impairment was required.

10. Impairment testing, continued:

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

Key assumptions – property, plant and equipment and definite life intangible assets recoverable amounts

The recoverable amounts for the Alberta CGUs were determined based on their respective fair value less cost to sell, estimated using discounted cash flows. The fair value measurement of the Alberta CGUs is categorized in Level 3 of the fair value hierarchy, as described in note 3, based on the inputs used in the valuation models. The calculation of the recoverable amounts for the Alberta CGUs are sensitive to several key assumptions as described below.

Discount rates

The after-tax discount rates used ranged within the respective CGUs and reflect the market weighted average cost of capital (WACC) using a capital asset pricing model approach, giving consideration to the risks specific to each CGU. The method and assumptions used to calculate the WACC rate are consistent with the Company's past experience and with previous valuations performed by the Company.

The discount rates used by the Company in the calculation of the recoverable amounts for the Alberta CGUs were as follows:

	Merchant	Contracted
Discount rate	9.0% to 10.0%	6.5% to 7.5%

Other key cash flow assumptions

The Company's cash flow projections incorporate estimates of annual plant revenues, expenses and capital expenditures to the end of each plant's useful life. These estimates incorporate past experience and the Company's current view of future generating capacity and natural gas forward pricing. The average forecasted Alberta power price is also a significant assumption used in determining the cash flows for any generation from the Alberta Commercial CGU that is not already sold forward at a contracted price as of the testing date. Forecasted Alberta power prices are also used for the post-PPA period for the Alberta Contracted CGU. The PPA for the Alberta Contracted CGU ends in 2020. Consideration is given to externally available information related to future pricing of electricity and natural gas inputs when developing certain pricing assumptions. Such external information is also used to validate the Company's current view of future pricing. These external sources of information include market information from the Alberta Electric System Operator (AESO) and information from third party advisory and research firms serving the industry.

The impact of the new carbon pricing under the proposed CCR has been incorporated into the cash flows. The Company assumed that the carbon pricing after 2018 will escalate at a rate of the Consumer Price Index to the end of the current estimated useful lives of the plants.

Given the uncertainty in the form, timing and amount of compensation associated with early closure of the coal plants, the cash flows assume that the coal plants will continue to operate until the end of their current estimated useful lives rather than 2030. As noted in the CLP, the Government is committed to ensuring that it would not unnecessarily strand capital through the compensation process. The Company will re-assess potential impairments arising from the early plant closures once there is reasonable certainty in respect of compensation.

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

10. Impairment testing, continued:

Goodwill and indefinite life intangible assets

The Company reviews its CGUs that contain goodwill on an annual basis, generally in the third quarter, to determine whether any impairment should be recognized. As a result, the Company's Southport CGU was tested for impairment during the third quarter of 2015. The carrying amount of the Southport CGU was within the range of its estimated recoverable amount and as such, no impairment was required (2014 – nil). The estimated recoverable amount of the Southport CGU exceeded its carrying amount by approximately $7 million (2014 - $3 million).

Key assumptions – goodwill and indefinite life intangible assets recoverable amounts

The recoverable amount of the Southport CGU was determined based on its fair value less costs to sell, estimated using discounted cash flows. The fair value measurement of the Southport CGU is categorized in Level 3 of the fair value hierarchy, as described in note 3, based on the inputs used in the valuation model. The calculation of the recoverable amount for the Southport CGU is sensitive to several key assumptions as described below.

Discount rates and growth rates

The after-tax discount rates used for the Southport CGU differed between the period for which the facility is currently contracted and the period following the expiry of the current contract, and reflect the market weighted average cost of capital (WACC) using a capital asset pricing model approach, giving consideration to the risks specific to the Southport CGU. The method and assumptions used to calculate the WACC rate are consistent with the Company's past experience and with previous valuations performed by the Company.

The Company has projected cash flows for a period of ten years and used a growth rate to extrapolate the cash flow projections beyond the ten year period through to the end of the useful life of the CGU. The growth rate reflects past experience and is consistent with industry practice.

The discount and growth rates used by the Company in the calculation of the recoverable amount for the Southport CGU were as follows:

	2015	2014
Discount rate – currently contracted period	6.8%	7.9%
Discount rate – post current contract period	8.8%	9.9%
Growth rate	2.0%	2.0%

Other key cash flow assumptions

The Company's cash flow projections incorporate estimates of annual plant revenues, expenses and capital expenditures. These estimates incorporate past experience and the Company's current view of future generating capacity, fuel mix, fuel pricing and expected contract renewal, including contracted rates, for the Southport facility.

The Company has assumed the Southport power purchase agreement will be extended for 10 years following the expiry of the current agreement in 2021 at rates consistent with current pricing, adjusted for 1% inflation. The Company has also assumed that the Southport facility will optimize its fuel mix at 50% wood waste, 45% tire-derived fuel (TDF), and 5% coal, and that long-term contracts will be executed with wood waste and TDF suppliers at prices consistent with current rates, adjusted for inflation.

Consideration is given to externally available information related to future electricity contract rates and fuel inputs when developing assumptions and such external information is used to validate the Company's current view of future rates and costs. These external sources of information include information from third party advisory and research firms serving the industry.

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

10. Impairment testing, continued:

Goodwill and indefinite life intangible assets, continued

Key assumptions – goodwill and indefinite life intangible assets recoverable amounts, continued

Sensitivities for key cash flow assumptions

Management has identified that a reasonably possible change in the following assumptions could cause the carrying amount to exceed the recoverable amount. The following table shows the amount by which these assumptions would need to change individually for the carrying amount to equal to the high end of the Southport CGU's estimated recoverable range:

	Change required
Discount rate – currently contracted and post current contract period, together	+0.3%
Growth rate	-3.7%
Annual cash flow projections	-2.3%

11. Cash and cash equivalents:

As at December 31	2015	2014
Cash on deposit	$ 72	$ 41
Cash equivalents	8	30
	$ 80	$ 71

Cash and cash equivalents includes $65 million (2014 - $32 million) related to margin posted with an exchange counterparty as a result of the Company's commodity trading activity. As part of its collateral requirements, the exchange counterparty updates its bank margin accounts daily, by recording fair value changes on unsettled derivative financial instruments outstanding with the Company.

Included in the Company's cash and cash equivalents is its proportionate share of its rights to cash and cash equivalents, which are restricted to use within its joint operations of $10 million (2014 - $18 million).

12. Trade and other receivables:

As at December 31	2015	2014
Accrued revenues	$ 121	$ 124
Trade receivables	41	33
Receivables from related parties	-	3
Finance lease receivable (note 15)	21	20
Allowance for doubtful accounts (note 30)	(5)	(5)
Net trade receivables	178	175
Income taxes recoverable	2	1
Prepayments	10	9
	$ 190	$ 185

Details of the aging of trade receivables and analysis of the movement on the allowance for doubtful accounts are provided in note 30.

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

13. Inventories:

As at December 31	2015	2014
Parts and other consumables	$ 60	$ 53
Coal	19	19
Emission credits	20	32
	$ 99	$ 104

Inventories expensed upon usage for the year ended December 31, 2015 of $144 million (2014 - $163 million) were charged to energy purchases and fuel, and other raw materials and operating charges. Emission credits held for trading are carried at fair value as estimated by quoted market prices available as of the valuation date. Details of the valuation techniques used in determining the fair values are described in note 14. No write-downs in inventories were recognized in the year ended December 31, 2015 (2014 - $1 million). There were no reversals of previous write downs recognized in the year ended December 31, 2015 (2014 - nil). As at December 31, 2015, no inventories were pledged as security for liabilities (2014 - nil).

14. 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 as described in note 30 consist of the following:

	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	$ 68	$ 5	$ 166
Non-current	22	32	-	-	54
Derivative instruments liabilities:					
Current	(2)	(25)	-	(11)	(38)
Non-current	(2)	(13)	-	-	(15)
Net fair value	$ 60	$ 45	$ 68	$ (6)	$ 167
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(8)	(3)			
Gigajoules of natural gas		19			
Metric tons of emission allowances		2			
Number of renewable energy credits		(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]	0.1 to 4.0	0.1 to 5.3	5.5 to 10.5	4.4 to 7.4	

[1] 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.

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

14. Derivative financial instruments and hedge accounting, continued:

	December 31, 2014				
	Energy and emission allowances		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 27	$ 80	$ 21	$ 4	$ 132
Non-current	26	29	-	-	55
Derivative instruments liabilities:					
Current	(1)	(58)	-	(5)	(64)
Non-current	(2)	(8)	-	-	(10)
Net fair value	$ 50	$ 43	$ 21	$ (1)	$ 113
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(8)	(6)			
Gigajoules of natural gas		5			
Metric tons of emission allowances		(2)			
Number of renewable energy credits		(2)			
Cross currency swaps and interest rate swaps (U.S. dollars)			$ 195	$ 100	
Interest rate swaps (Canadian dollars)				$ 100	
Range of remaining contract terms in years [2]	0.1 to 4.0	0.1 to 6.3	6.5 to 11.5	6.5 to 10.9	

[2] Terms of certain foreign exchange cash flow hedge contracts and interest rate non-hedge contracts require settlement in 2.0 years and 0.9 years respectively. The remaining years of the underlying derivatives of these contracts are reflected in the table above.

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices dependent on which is most representative of fair value in the circumstances, in the principal market for that instrument. The extent to which fair values of derivative instruments are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. When traded markets are not considered to be sufficiently active or do not exist, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates and maximize, when available, the use of external readily observable market data including future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rates, counterparty credit risk, the Company's own credit risk and volatility. When a valuation technique utilizes unobservable market data, no inception gains or losses are recognized, until inputs become observable. 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. As at December 31, 2015 and, 2014, the Company classified all financial instruments under Level 2 of the fair value hierarchy described in note 3.

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

14. Derivative financial instruments and hedge accounting, continued:

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

	2015		2014	
	Unrealized gains (losses)	Realized gains	Unrealized gains	Realized gains
Energy cash flow hedges	$ 20	$ 81	$ 49	$ 22
Energy and emission allowances non-hedges	-	51	34	43
Foreign exchange cash flow hedges[3]	-	2	2	-
Interest rate non-hedges	(5)	3	-	2

[3] For the year ended December 31, 2015, unrealized gains of $47 million (2014 – unrealized gains of $19 million) related to foreign exchange cash flow hedges were reclassified from other comprehensive income to net income to offset the impact of unrealized foreign exchange losses from the revaluation of U.S. dollar denominated loans and borrowings.

Realized and unrealized gains and losses relate only to derivative financial instruments. The following realized and unrealized gains and losses are included in the Company's statements of income for the years ended December 31, 2015 and 2014:

	2015	2014
Revenues	$ 234	$ 311
Energy purchases and fuel	(102)	(212)
Foreign exchange loss	47	19
Finance expense	(2)	2

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 year ended December 31, 2015, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statement of income was nil (2014 - nil).

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

As at December 31	2015
Within one year	$ 43
Between one and five years	21
After five years	-
	$ 64

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

15. Leases:

Finance lease receivables

	Minimum lease payments		Present value of minimum lease payments	
As at December 31	2015	2014	2015	2014
Amounts receivable under finance leases:				
Less than one year	$ 57	$ 57	$ 21	$ 20
Between one and five years	229	229	94	89
More than five years	868	925	595	619
Unearned finance income	(444)	(483)	-	-
Lease payment receivable	710	728	710	728
Less current portion: (included within trade and other receivables (note 12))	21	20	21	20
	$ 689	$ 708	$ 689	$ 708

The PPAs pertaining to the Company's wind generation facilities located in Ontario (Kingsbridge 1 and Port Dover and Nanticoke) and British Columbia (Quality Wind) are finance leases and expire in 2026, 2033 and 2037 respectively and have effective rates inherent in the leases of 3.21%, 6.16% and 4.86% respectively. The lease receivables contain unguaranteed residual values of $13 million, $44 million and nil for the Kingsbridge, Port Dover and Nanticoke and Quality Wind facilities respectively.

Details of the fair value of the finance lease receivables are provided in note 29.

Finance income of $37 million was recognized in revenues during the year ended December 31, 2015 (2014 - $43 million).

Finance lease obligation

	Minimum lease payments		Present value of minimum lease payments	
As at December 31	2015	2014	2015	2014
Amounts payable under finance leases:				
Less than one year	$ 2	$ -	$ 1	$ -
Between one and five years	8	-	5	-
More than five years	19	-	16	-
Interest costs	(7)	-	-	-
Lease obligation	22	-	22	-
Less current portion: (included within trade and other payables (note 21))	1	-	1	-
	$ 21	$ -	$ 21	$ -

During the year ended December 31, 2015 the Company sold its Beaufort solar generating facility (Beaufort Solar) and immediately leased the facility back under a finance lease which expires in 2025 and has an effective rate inherent in the lease of 4.50%. Details of the assets under finance lease are provided in note 19.

Details of the fair value of the finance lease obligation are provided in note 29.

No interest expense was recognized in finance expense during the year ended December 31, 2015 as the lease was entered into on December 28, 2015 (2014 - nil).

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

15. Leases, continued:

Facilities under operating leases

Certain power generation facilities owned by the Company operate under PPAs that convey the right to the holder of the agreement to use the related property, plant and equipment. Consequently, the Roxboro, Genesee units 1 and 2, and Island Generation power generation facilities are accounted for as assets under operating leases.

As at December 31, 2015, the cost of such property, plant and equipment was $1,230 million (2014 - $1,211 million), less accumulated depreciation of $312 million (2014 - $268 million).

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

As at December 31	2015
Within one year	$ 62
Between one and five years	253
After five years	19
	$ 334

16. Other financial assets:

As at December 31	2015	2014
Loans and other long-term receivables	$ 12	$ 16
Available for sale - portfolio investments	1	2
	$ 13	$ 18

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

17. Deferred tax:

Movement of deferred tax balances

	As at January 1, 2015	Recognized in net income	Recognized directly in other comprehensive income	Amounts relating to acquisitions and disposals	Recognized directly in loans and borrowings	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2015	Deferred tax assets	Deferred tax liabilities
Losses carried forward	$ 21	$ 10	$ -	$ -	$ -	$ 8	$ (9)	$ 30	$ 30	$ -
Property, plant and equipment	(153)	(57)	(4)	(32)	-	-	-	(246)	-	(246)
Intangible assets	12	(1)	(1)	5	-	-	-	15	19	(4)
Deferred partnership income	(1)	(6)	-	-	-	-	-	(7)	-	(7)
Derivative financial instruments	(25)	(9)	(7)	(3)	-	-	-	(44)	26	(70)
Share issue costs and deferred financing charges	2	(2)	-	-	-	1	-	1	1	-
Equity-accounted investment	5	(12)	3	-	-	-	-	(4)	-	(4)
Deferred revenue and other liabilities	23	4	1	4	-	-	-	32	32	-
Finance lease receivables	(149)	(7)	-	(36)	-	-	-	(192)	-	(192)
Decommissioning provisions	37	7	2	6	-	-	-	52	52	-
Goodwill	(8)	-	(2)	-	-	-	-	(10)	-	(10)
Prepaid reclamation amounts	(14)	(2)	-	(3)	-	-	-	(19)	-	(19)
Other provisions	11	(1)	(1)	-	-	-	-	9	9	-
Loans and borrowings	6	19	-	(2)	(4)	-	-	19	19	-
Other assets	5	1	-	-	-	-	-	6	6	-
Deferred tax assets (liabilities)	$ (228)	$ (56)	$ (9)	$ (61)	$ (4)	$ 9	$ (9)	$ (358)	$ 194	$ (552)
Set-off of tax								-	(176)	176
Net deferred tax assets (liabilities)								$ (358)	$ 18	$ (376)

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

17. Deferred tax, continued:

Movement of deferred tax balances, continued

	As at January 1, 2014	Recognized in net income	Recognized directly in other compre-hensive income	Amounts relating to acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2014	Deferred tax assets	Deferred tax liabilities
Losses carried forward	$ 84	$ (65)	$ 3	$ -	$ 7	$ (11)	$ 18	$ 18	$ -
Property, plant and equipment	(81)	(40)	-	(32)	-	-	(153)	-	(153)
Intangible assets	20	-	-	(8)	-	-	12	18	(6)
Deferred partnership income	4	(2)	-	-	-	-	2	2	-
Derivative financial instruments	(5)	(10)	(10)	-	-	-	(25)	25	(50)
Share issue costs and deferred financing charges	5	(3)	-	-	-	-	2	2	-
Equity-accounted investment	-	-	5	-	-	-	5	5	-
Deferred revenue and other liabilities	20	(1)	-	4	-	-	23	23	-
Finance lease receivables	(148)	1	-	(2)	-	-	(149)	-	(149)
Decommissioning provisions	27	7	1	2	-	-	37	37	-
Goodwill	(8)	1	(1)	-	-	-	(8)	-	(8)
Prepaid reclamation amounts	(14)	-	-	-	-	-	(14)	-	(14)
Other provisions	9	2	-	-	-	-	11	11	-
Loans and borrowings	(1)	-	-	7	-	-	6	7	(1)
Other assets	3	2	-	-	-	-	5	5	-
Deferred tax assets (liabilities)	$ (85)	$ (108)	$ (2)	$ (29)	$ 7	$ (11)	$ (228)	$ 153	$ (381)
Set-off of tax							-	(132)	132
Net deferred tax assets (liabilities)							$ (228)	$ 21	$ (249)

Unrecognized deferred tax assets

Deferred tax assets have not been recognized on the following items as it is not probable the future taxable income will be available against which the Company can use the benefits therefrom.

As at December 31	2015	2014
Non-capital losses	$ 341	$ 294
Deductible temporary differences with no expiry	199	164
	$ 540	$ 458

Tax losses carried forward

	2015		2014	
	Tax losses	Expiry dates	Tax losses	Expiry dates
Unrecognized tax losses carried forward	$ 341	2027-2035	$ 294	2027-2034

As at December 31, 2015, the Company has non-capital losses carried forward of $455 million (2014 - $365 million), of which $328 million (US$237 million) (2014 - $281 million (US$242 million)) relates to U.S. subsidiaries.

During the year ended December 31, 2014, the Company reversed previously recognized deferred tax assets of $73 million (US$66 million) relating to non-capital losses of $216 million (US$186 million) from U.S. subsidiaries that will expire between 2027 and 2033.

The deferred tax assets presented on the consolidated statements of financial position are recoverable based on estimated future net income and the reversal of taxable temporary differences. The assumptions used in the estimate of future net income are based on the Company's cash flow projections, which include estimates described in note 10.

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

18. Intangible assets:

	Intangible work in progress	PPAs	Contract rights	Other rights	Emission credits	Software	Total
Cost							
As at January 1, 2014	$ 30	$ 140	$ 35	$ 109	$ 29	$ 42	$ 385
Additions from separate acquisition	10	-	-	6	16	-	32
Additions into service	(5)	-	-	1	-	4	-
Acquisition though business combination (note 9)	36	-	-	-	-	-	36
Retirements and other disposals	-	-	-	-	(1)	(1)	(2)
Transfers to finance lease receivables	(5)	-	-	-	-	-	(5)
As at December 31, 2014	$ 66	$ 140	$ 35	$ 116	$ 44	$ 45	$ 446
Additions	4	-	-	-	11	-	15
Additions into service	(45)	-	2	37	-	6	-
Disposal through sale and leaseback	(2)	-	-	-	-	-	(2)
Retirements and other disposals	-	-	-	-	(9)	-	(9)
Transfers from property, plant and equipment (note 19)	-	-	-	4	-	-	4
Foreign currency translation adjustments	4	-	-	3	-	-	7
As at December 31, 2015	$ 27	$ 140	$ 37	$ 160	$ 46	$ 51	$ 461
Accumulated amortization							
As at January 1, 2014	$ -	$ (55)	$ (3)	$ (7)	$ -	$ (10)	$ (75)
Amortization (note 5)	-	(12)	(2)	(2)	-	(5)	(21)
As at December 31, 2014	$ -	$ (67)	$ (5)	$ (9)	$ -	$ (15)	$ (96)
Amortization (note 5)	-	(12)	(2)	(4)	-	(6)	(24)
As at December 31, 2015	$ -	$ (79)	$ (7)	$ (13)	$ -	$ (21)	$ (120)
Net book value							
As at January 1, 2014	$ 30	$ 85	$ 32	$ 102	$ 29	$ 32	$ 310
As at December 31, 2014	$ 66	$ 73	$ 30	$ 107	$ 44	$ 30	$ 350
As at December 31, 2015	$ 27	$ 61	$ 30	$ 147	$ 46	$ 30	$ 341

Acquired PPAs are recorded at the cost of acquisition. Under the terms of the Company's Sundance and Joffre PPAs, the Company is obligated to make fixed and variable payments to the owners of the underlying generation units over their respective terms. Such amounts are recorded as operating expenses as incurred.

The Sundance PPA is owned under an equity syndication agreement with an equity syndicate. Under the terms of the agreement, the syndicate members receive their proportionate share of the committed generating capacity in exchange for their proportionate share of the price paid for the Sundance PPA and all payments to the generation unit owners.

Contract rights include the cost of acquired management and operations agreements and a 20-year agreement whereby the Company will sell Renewable Energy Credits produced by the Halkirk Wind Project to a third party.

Other rights include the cost of land lease agreements for use in wind power projects in Alberta and Ontario, solar power projects in the United States, and coal supply access rights relating to the Keephills 3 Project.

Impairments

No impairments of intangible assets were recognized during the year ended December 31, 2015 (2014 - nil). No previous impairments of intangible assets were reversed during the year ended December 31, 2015 (2014 - nil).

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the years ended December 31, 2015 or 2014.

Restrictions on assets

There are no charges over the Company's intangible assets.

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

19. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment	Total
Cost				
As at January 1, 2014	$ 676	$ 107	$ 3,283	$ 4,066
Additions	201	-	-	201
Additions into service	(69)	4	65	-
Acquisitions through business combination (note 9)	-	-	103	103
Retirements and other disposals	-	(3)	(37)	(40)
Transfers to finance lease receivables	(1)	-	(7)	(8)
Revisions to decommissioning costs (note 23)	-	-	32	32
Foreign currency translation adjustments	-	-	12	12
As at December 31, 2014	$ 807	$ 108	$ 3,451	$ 4,366
Additions	142	-	-	142
Additions into service	(878)	9	869	-
Additions through finance lease	-	-	22	22
Disposal through sale and leaseback	(39)	-	-	(39)
Retirements and other disposals	(2)	(1)	(22)	(25)
Transfers to intangible assets (note 18)	(4)	-	-	(4)
Transfers to finance lease receivables	-	-	(1)	(1)
Revisions to decommissioning costs (note 23)	-	-	12	12
Foreign currency translation adjustments	1	-	51	52
As at December 31, 2015	$ 27	$ 116	$ 4,382	$ 4,525
Accumulated depreciation				
At January 1, 2014	$ -	$ -	$ (541)	$ (541)
Depreciation (note 5)	-	-	(155)	(155)
Retirements and other disposals	-	-	37	37
Foreign currency translation adjustments	-	-	(6)	(6)
As at December 31, 2014	$ -	$ -	$ (665)	$ (665)
Depreciation (note 5)	-	-	(186)	(186)
Retirements and other disposals	-	-	21	21
Foreign currency translation adjustments	-	-	(16)	(16)
As at December 31, 2015	$ -	$ -	$ (846)	$ (846)
Net book value				
As at January 1, 2014	$ 676	$ 107	$ 2,742	$ 3,525
As at December 31, 2014	$ 807	$ 108	$ 2,786	$ 3,701
As at December 31, 2015	$ 27	$ 116	$ 3,536	$ 3,679

Assets under finance lease

During the year ended December 31, 2015 the Company sold Beaufort Solar, which consisted of property, plant and equipment and intangible assets, for gross proceeds of $46 million (US$34 million) and immediately leased the facility back under a finance lease agreement described in note 15. The Company recorded a gain of $5 million (US$4 million) for the year ended December 31, 2015 (2014 – nil) to deferred revenue which will be amortized over the lease term. As at December 31, 2015, the asset under finance lease had a net book value of $22 million (2014 – nil) and the Company recorded depreciation expense of nil during the year ended December 31, 2015.

Impairments

No impairments of property, plant and equipment were recognized during the year ended December 31, 2015 (2014 - nil) as described in note 10. No reversals of impairments on property, plant and equipment were recognized during the year ended December 31, 2015 (2014 - nil).

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

19. Property, plant and equipment, continued:

Capitalized borrowing costs

Details of borrowing costs capitalized as part of property, plant and equipment are provided in note 6. The average borrowing rate used to capitalize interest during the year was 4.87% (2014 – 5.26%) for projects financed using general borrowings. For the years ended December 31, 2015 and 2014, there were no projects financed using specific borrowings that were included as part of property, plant and equipment.

Restrictions on assets

Details of charges over land, plant and equipment are provided in note 22.

20. Goodwill:

	2015	2014
Cost and net book value		
As at January 1	$ 25	$ 23
Foreign currency translation adjustments	5	2
As at December 31	$ 30	$ 25

The aggregate carrying amounts of goodwill allocated to the Company's CGUs at December 31, 2015 and 2014 are substantially all related to the Company's Southport CGU.

Impairments

No impairments of goodwill were recorded in the consolidated statement of income for the year ended December 31, 2015 (2014 – nil).

21. Trade and other payables:

As at December 31	2015	2014
Operating accruals	$ 95	$ 99
Trade payables	33	29
Dividends and distributions payable	36	35
Accrued interest	14	15
Finance lease obligation (note 15)	1	-
Taxes payable	2	7
	$ 181	$ 185

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

22. Loans and borrowings:

	Effective interest rate	December 31, 2015	December 31, 2014
Unsecured senior medium-term notes, payable semi-annually			
Issued by CPC, at 4.85% due in 2019[1]	4.96%	$ 250	$ 250
Issued by CPC, at 5.28% due in 2020[1]	5.34%	300	300
Issued by CPLP, at 4.60% repaid in 2015	4.69%	-	249
		550	799
CPLP unsecured senior debt, payable annually to EPCOR			
At 6.75% due in 2016	6.16%	130	130
At 5.80% due in 2018	5.63%	164	164
At 9.00% due between 2016 and 2018	7.41%	31	40
		325	334
CPLP unsecured senior notes, payable semi-annually			
US$230, at 5.21% due in 2021	5.29%	318	267
US$65, at 5.61% due in 2026	5.67%	90	75
		408	342
CPLP non-recourse financing, payable quarterly			
Joffre Cogeneration Project, at 8.59%, due in 2020	8.31%	24	29
Macho Springs, US $50 at 6.90%, due in 2031	7.00%	69	59
		93	88
CPLP tax-equity financing, payable quarterly			
Macho Springs, US$7 at 13.85%	13.85%	10	16
CPLP revolving extendible credit facilities			
US$20, at floating rates, due in 2020	2.35%	27	17
At floating rates, due in 2020	2.30%	212	-
		239	17
Total debt payable		1,625	1,596
Less: current portion		339	599
		1,286	997
Less: deferred debt issue costs		10	10
		$ 1,276	$ 987

[1] On December 18, 2015, all issued and outstanding medium-term notes of CPLP were exchanged for an equal principal amount of newly issued medium-term notes of Capital Power, having identical terms and conditions.

Unsecured senior debt payable to EPCOR

The unsecured senior debt payable to EPCOR matures between 2016 and 2018. As at December 31, 2015, since EPCOR does not own any of the outstanding limited partnership units of CPLP (2014 – owns less than 20%), EPCOR may, by written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon. As a result, as at December 31, 2015 and 2014, all of the unsecured senior debt payable to EPCOR has been classified as current loans and borrowings.

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

22. Loans and borrowings, continued:

Non-recourse financing

Joffre Cogeneration Project financing represents the Company's share of syndicated loans for the project. The debt is secured by a charge against project assets which have a carrying amount of $58 million.

Macho Springs financing represents loans for the project. The debt is secured by a charge against project assets which have a carrying amount of $114 million.

Tax-equity financing

Macho Springs tax-equity financing represents the initial equity investment made by the project investor adjusted for earnings, tax benefits and cash distributions paid to date. The maturity date of this obligation is subject to change and is driven by the date on which the project investor reaches the agreed upon target rate of return. The Company anticipates the maturity date will occur in 2017.

CPLP revolving extendible credit facilities

Unsecured credit facilities of $700 million committed to 2020 and uncommitted amounts of $20 million are available to CPLP. As at December 31, 2015, the Company had bankers' acceptances of $212 million (2014 – nil) and U.S. prime loans of $27 million (US$20 million) (2014 - $17 million (US$14 million)) outstanding under these facilities. Additional uncommitted amounts of $5 million are available to the Company and are undrawn at December 31, 2015 (2014 – $5 million).

The Company also has committed credit facilities of $300 million and demand bilateral credit facilities of $200 million for a total of $500 million of unsecured credit facilities available through its CPLP subsidiary. These facilities have a maturity date of July 9, 2020. As at December 31, 2015, no amounts have been drawn on these facilities (2014 – nil), and letters of credit of $125 million (2014 – $122 million) have been issued as described in note 35.

Under the terms of the extendible facilities, the Company's subsidiary, CPLP, may obtain advances by way of Canadian or U.S. prime loans, U.S. base rate loans, U.S. LIBOR loans and bankers' acceptances. Amounts drawn by way of prime or base rate loans each bear interest at the prevailing Canadian Prime, U.S. Prime, or U.S. base rate respectively, plus a spread ranging from nil to 1.25%, depending on CPLP's credit rating. Amounts drawn by way of U.S. LIBOR loans or bankers' acceptances bear interest at the prevailing LIBOR rate or applicable bankers' acceptance rate plus a spread ranging from 1.00% to 2.25%, depending on CPLP's credit rating.

23. Provisions:

As at December 31	2015	2014
Decommissioning	$ 184	$ 161
Employee benefits [1]	46	56
Other	2	3
	232	220
Less: current portion	22	22
	$ 210	$ 198

[1] Included in the employee benefits provision is $6 million pertaining to the share-based payment obligations described in note 28, of which $6 million is vested at December 31, 2015 (2014 - $13 million total share-based payment obligation, $13 million vested).

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

23. Provisions, continued:

	Decommissioning	Employee benefits	Other	Total
As at January 1, 2014	$ 120	$ 50	$ 5	$ 175
Additional liabilities incurred	2	22	(1)	23
Additional liabilities acquired in business combination (note 9)	3	-	-	3
Liabilities settled	(1)	(15)	-	(16)
Amounts reversed unused	1	(1)	(1)	(1)
Foreign currency translation adjustments	1	-	-	1
Revisions to decommissioning costs (note 19)	32	-	-	32
Unwinding of the discount (note 6)	3	-	-	3
As at December 31, 2014	$ 161	$ 56	$ 3	$ 220
Additional liabilities incurred	3	10	-	13
Liabilities settled	(1)	(18)	-	(19)
Amounts reversed unused	-	(2)	(1)	(3)
Foreign currency translation adjustments	5	-	-	5
Revisions to decommissioning costs (note 19)	12	-	-	12
Unwinding of the discount (note 6)	4	-	-	4
As at December 31, 2015	$ 184	$ 46	$ 2	$ 232

Decommissioning provisions

The Company has recorded decommissioning provisions for its power generation facilities and the Genesee coal mine as it is obliged to remove the facilities at the end of their useful lives and restore the power facilities 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.

At December 31, 2015, the Company's estimate of the undiscounted cash flow required to settle its decommissioning obligations is approximately $318 million, calculated using an inflation rate of 2%. The expected timing for settlement of the obligations is between 2016 and 2061, which reflects the anticipated useful lives of the different power facilities. The majority of the payments to settle the obligations are expected to occur between 2044 and 2055 for the power generation facilities and in 2055 for the un-reclaimed sections of the Genesee coal mine. Discount rates used to calculate the carrying amount of the obligations range from 0.49% to 2.65%. The actual timing and costs to settle decommissioning obligations may vary from estimates as a result of changes to contractor rates required to perform the decommissioning.

No assets have been legally restricted for settlement of these liabilities.

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

24. Share capital:

Authorized shares

	Number of shares authorized
Common shares	unlimited
Preference shares, issuable in series:	
Series 1 and 2	5 million
Series 3, 4 and 8	6 million
Series 5 and 6	8 million
Special voting shares	unlimited
Special limited voting share	one

Issued and fully paid shares

	Common shares		Preference shares		Special voting shares	
	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
As at January 1, 2014	80,889,878	$ 1,864	19,000,000	$ 464	18,841,000	$ -
Share purchase options exercised (note 28)	1,028,778	26	-	-	-	-
Dividend reinvestment plan	1,542,240	37	-	-	-	-
As at December 31, 2014	83,460,896	$ 1,927	19,000,000	$ 464	18,841,000	$ -
Shares exchanged [1]	18,841,000	449	-	-	(18,841,000)	-
Deferred taxes on share issue costs (note 17)	-	1	-	-	-	-
Share purchase options exercised (note 28)	76,580	2	-	-	-	-
Dividend reinvestment plan[2]	882,103	22	-	-	-	-
Common shares purchased[3]	(5,880,736)	(121)	-	-	-	-
As at December 31, 2015	97,379,843	$ 2,280	19,000,000	$ 464	-	$ -

[1] On April 2, 2015, EPCOR exchanged 9,450,000 of its exchangeable limited partnership units of CPLP on a one-for-one basis for common shares of Capital Power and subsequently completed its sale of the 9,450,000 common shares at an offering price of $23.85 per common share for aggregate gross proceeds of $225 million. In connection with the offering, EPCOR exchanged its remaining 9,391,000 outstanding exchangeable limited partnership units in CPLP for common shares of Capital Power in accordance with the terms of the exchangeable common limited partnership units. As a result of the unit exchange and share offering, EPCOR's ownership interest in CPLP was reduced to nil (December 31, 2014 – 18%) and Capital Power's interest in CPLP increased to 100% (December 31, 2014 – 82%); therefore EPCOR ceased to be a related party of the Company.

[2] Effective for the June 30, 2015 dividend, Capital Power suspended its dividend reinvestment plan for its common shares until further notice.

[3] On March 25, 2015, the Toronto Stock Exchange (TSX) approved Capital Power's normal course issuer bid (NCIB) to purchase and cancel up to 5,000,000 of its outstanding common shares during the one year period from April 7, 2015 to April 6, 2016. On November 27, 2015, the TSX approved an amendment to Capital Power's NCIB to increase the number of shares to purchase and cancel up to 8,369,838 of its outstanding common shares during the same one year period. During the year ended December 31, 2015, the Company purchased and canceled 5,880,736 of its outstanding common shares (2014 – nil).

The Company's shares are subject to a Shareholder Rights Plan (Rights Plan). The objective of the Rights Plan is to ensure, to the extent possible, the fair treatment of all shareholders in connection with any take-over bid for the securities of the Company, and to provide the Board with sufficient time to evaluate unsolicited take-over bids and to explore and develop alternatives to maximize shareholder value. The Rights Plan will continue in force until the end of the annual meeting of shareholders in 2016 subject to any changes in applicable securities law requirements.

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

24. Share capital, continued:

Cumulative rate reset preference shares

Preferred shares	Dividend per share per annum[4]	Dividend rate reset	Redemption terms	Conversion terms[5]
Series 1	$1.150	Dividend rate was reset from $1.150 per annum to $0.765 per annum effective December 31, 2015 for the March 31, 2016 dividend payment and will be reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%.	Series 1 shares are redeemable by Capital Power, at its option, on December 31, 2020 and on December 31 of every fifth year thereafter.	Right to convert all or any part of shares into Series 2 Cumulative Floating Rate Preference Shares, subject to certain conditions, on December 31, 2020 and on December 31 of every fifth year thereafter.
Series 3	$1.150	Dividend rate will be reset on December 31, 2018 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.23%.	Series 3 shares are redeemable by Capital Power, at its option, on December 31, 2018 and on December 31 of every fifth year thereafter.	Right to convert all or any part of their shares into Series 4 Cumulative Floating Rate Preference Shares, subject to certain conditions, on December 31, 2018 and on December 31 of every fifth year thereafter.
Series 5	$1.125	Dividend rate will be reset on June 30, 2018 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.15%.	Series 5 shares are redeemable by Capital Power, at its option, on June 30, 2018 and on June 30 of every fifth year thereafter.	Right to convert all or any part of their shares into Series 6 Cumulative Floating Rate Preference Shares, subject to certain conditions, on June 30, 2018 and on June 30 of every fifth year thereafter.

[4] Holders of Series 1, Series 3, and Series 5 shares will be entitled to receive fixed cumulative quarterly dividends that yield 4.60% (reset to 3.06% effective for the March 31, 2016 dividend payment), 4.60%, and 4.50%, respectively, per annum payable on the last business day of March, June, September, and December of each year, as and when declared by the board of directors of Capital Power.

[5] Holders of Series 2, Series 4, and Series 6 shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.17%, 3.23% and 3.15%, respectively, as and when declared by the board of directors of Capital Power.

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

24. Share capital, continued:

The common and preferred share dividends declared and paid by the Company for the years ended December 31, 2015 and 2014 are summarized as follows:

	Dividends declared				Dividends paid			
	2015		2014		2015		2014	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common [6,7]	$ 1.4100	$ 135	$ 1.3100	$ 108	$ 1.3850	$ 128	$ 1.2850	$ 105
Preference, Series 1	1.1500	6	1.1500	6	1.1500	6	1.1500	6
Preference, Series 3	1.1500	7	1.1500	7	1.1500	7	1.1500	7
Preference, Series 5	1.1250	9	1.1250	9	1.1250	9	1.1250	9

[6] On July 27, 2015, the Company's Board of Directors approved an increase of 7.4% in the annual dividend to $1.46 per common share effective for the third quarter of 2015.

[7] For the year ended December 31, 2015, dividends paid on common shares consist of $106 million paid in cash and $22 million paid through the Company's dividend reinvestment plan as common shares issued. For the year ended December 31, 2014, dividends paid on common shares consist of $68 million paid in cash and $37 million paid through the Company's dividend reinvestment plan as common shares issued.

25. Other reserves:

Components of other comprehensive income and other reserves are established as follows:

Cash flow hedges

The cash flow hedging reserve represents the cumulative portion of gains and losses on hedging instruments deemed effective in cash flow hedges. The cumulative deferred gains or losses on the hedging instrument is reclassified to net income or loss only when the hedged transaction affects the net income or loss, or is included as a basis adjustment to the non-financial hedged item, consistent with the relevant accounting policy.

Cumulative translation reserve

The cumulative translation reserve for foreign operations represents the cumulative portion of gains and losses on retranslation of foreign operations that have a functional currency other than Canadian dollars. The cumulative deferred gain or loss on the foreign operation is reclassified to net income or loss only on disposal of the foreign operation.

Defined benefit plan actuarial gains and losses

The defined benefit plan actuarial gains and losses represent the cumulative differences between actual and expected experience and from changes in actuarial assumptions used to determine the accrued benefit obligation.

Employee benefits reserve

The equity-settled employee benefits reserve reflects share options granted to employees under the employee share option plan. Information about share-based payments to employees is disclosed in note 28.

26. Change in non-cash operating working capital:

Year ended December 31	2015	2014
Trade and other receivables	$ 11	$ 25
Inventories	13	(13)
Trade and other payables	(5)	(6)
Deferred revenue and other liabilities	(1)	(1)
Provisions	(7)	(4)
	$ 11	$ 1

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

27. Related party balances and transactions:

Nature of transactions

As described in note 33, the Company is party to a number of joint arrangements, primarily for the construction and operation of power generating facilities. The joint arrangements provide energy to the Company and the Company provides management and operation services to the joint arrangements. Transactions with joint arrangements are eliminated to the extent of the Company's interest in the joint arrangement.

The Company provides electricity to EPCOR's residential customers and EPCOR provides distribution and transmission services to the Company along with various other services pursuant to service agreements arranged with EPCOR.

EPCOR was a related party of Capital Power until April 2, 2015, following the secondary offering and exchange of exchangeable common limited partnership units, as described in note 24, which decreased EPCOR's interest in the Company to nil. The City of Edmonton, as the sole shareholder of EPCOR, was also a related party of Capital Power until April 2, 2015.

Transactions and balances

The following transactions took place during the period from January 1, 2015 to April 2, 2015 and the year ended December 31, 2014 between the Company and its related parties:

	Period from January 1, 2015 to April 2, 2015	Year ended December 31, 2014
Revenues – energy sales:		
EPCOR and City of Edmonton [1]	$ 5	$ 13
Energy purchases and fuel:		
EPCOR	-	2
Purchase of raw materials and other services:		
EPCOR	2	8
Finance expense:		
EPCOR	5	13

[1] Energy sales of $5 million (2014 - $11 million) to EPCOR, and nil (2014 - $2 million) to the City of Edmonton.

In addition to the transactions described above, the Company's subsidiary CPLP has recorded total distributions of $6 million to EPCOR for the year ended December 31, 2015 (2014 - $25 million). CPLP paid distributions of $13 million to EPCOR in the year ended December 31, 2015 (2014 - $24 million).

Compensation of key management personnel

Year ended December 31	2015	2014
Short-term employee benefits	$ 5	$ 5
Share-based payments	-	4
	$ 5	$ 9

Key management personnel include certain executive officers of the Company in addition to the Directors of the Company.

28. Share-based payments:

Share purchase options

Under the Company's long-term incentive plan, the Company provides share purchase options to certain employees to purchase common shares, provided that the number of shares reserved for issuance will not exceed 10% of the common shares to be outstanding at closing and that the aggregate number of shares issued by the Company under this plan will not exceed 7,094,506 common shares.

In March 2015, the Company granted 671,804 share purchase options with one third vesting on March 4 of each of 2016, 2017 and 2018. The fair values of these options at grant date were $1.73, $1.79 and $1.80 per option for the 2016, 2017 and 2018 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $24.88 per share.

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

28. Share-based payments, continued:

Share purchase options, continued

In March 2014, the Company granted 725,571 share purchase options with one third vesting on March 12 of each of 2015, 2016 and 2017. The fair values of these options at grant date were $1.83, $1.90 and $1.96 per option for the 2015, 2016 and 2017 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $24.80 per share.

The following assumptions were used in estimating the fair value of the granted share purchase options:

	Share purchase options issued in: 2015	2014
Share price at grant date	$ 24.88	$ 24.80
Expected volatility [1]	15.33%	15.20%
Expected option life [2]	4.5 years	4.5 years
Expected dividend yield	5.27%	5.08%
Risk-free interest rate [3]	1.29%	1.85%
Exercise price	$ 24.88	$ 24.80
Expiry date	March 4, 2022	March 12, 2021

[1] Volatility was estimated based on the historical volatility in the share prices of the Company's peer group.

[2] Represents the average expected life of the three tranches for each grant date.

[3] Based on the Government of Canada zero-coupon yield curve. Represents the average risk-free rate of the three tranches for each grant date.

The following illustrates the movements on share purchase options during the years ended December 31, 2015 and 2014:

	2015		2014	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Options outstanding, as at January 1	3,757,449	$ 23.72	4,210,458	$ 23.44
Granted	671,804	24.88	725,571	24.80
Exercised [4]	(76,580)	23.09	(1,028,778)	23.41
Forfeited	(611,349)	23.88	(149,802)	23.37
Expired	(32,486)	24.80	-	-
Options outstanding, as at December 31	3,708,838	$ 23.90	3,757,449	$ 23.72
Vested options outstanding, as at December 31	2,604,377	$ 23.69	2,319,938	$ 23.65

[4] The weighted average share price at the date of exercise was $24.67 (2014 - $26.10)

During the year ended December 31, 2015, the Company recorded compensation expense of nil related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2014 - $1 million).

The weighted average remaining contractual life of the Company's outstanding share purchase options as at December 31, 2015 is 2.47 years (2014 – 4.0 years). The exercise prices of share purchase options outstanding as at December 31, 2015 range from $21.76 to $24.90 (2014 - $21.76 to $24.90).

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

28. Share-based payments, continued:

Performance share units

Capital Power grants performance share units (PSUs) to certain employees, which entitle those employees to receive payments based on an equivalent number of common shares at a specified release date for an amount based on the prevailing market price of such number of common shares on the release date. PSUs are paid out three years from the grant date and vest as service is rendered over that three-year period. Participants receive payments based on the number of units vested including dividend equivalents with an ending value based on the prevailing market price at the time of payment. PSUs will be paid in cash based on the Company's share performance relative to a group of peer organizations ranging from 0% to 200% times the market price of the PSU at the release date.

	2015	2014
PSUs outstanding, as at January 1	358,294	378,436
Granted [5]	100,770	105,777
Released [6]	(88,750)	(76,613)
Dividends reinvested	21,372	35,737
Forfeited	(71,714)	(85,043)
PSUs outstanding, as at December 31	319,972	358,294

[5] The fair value of the PSUs at the grant date was $25.97 (2014 - $23.48).

[6] The weighted average share price at the date of release was $25.93 (2014 - $22.45).

During the year ended December 31, 2015, the Company recorded compensation recovery of $2 million (2014 – expense of $5 million) related to the outstanding PSUs in staff costs and employee benefits expense.

Restricted share units

Capital Power grants restricted share units (RSUs) to certain employees, which entitle those employees to receive payments based on an equivalent number of common shares at a specified release date for an amount equal to the market price of such number of common shares on the release date. RSUs are paid out three years from the grant date and vest as service is rendered over that three-year period. RSUs will be paid out to participants in cash based on the number of units vested including dividend equivalents with an ending value equal to the prevailing market price of Capital Power common shares at the time of payment.

	2015	2014
RSUs outstanding, as at January 1	84,181	-
Granted [7]	85,982	89,368
Released [8]	(2,206)	(1,544)
Dividends reinvested	9,158	3,195
Forfeited	(3,915)	(6,838)
RSUs outstanding, as at December 31	173,200	84,181

[7] The fair value of the RSUs at the grant date was $25.97 (2014 – $23.48).

[8] The weighted average share price at the date of release was $21.30 (2014 – $25.96).

During the year ended December 31, 2015, the Company recorded compensation expense of $1 million (2014 – $1 million) related to the outstanding RSUs in staff costs and employee benefits expense.

Deferred stock units

The Company has approved a deferred stock unit (DSU) plan pursuant to which non-employee directors of the Company may receive their annual equity retainer in the form of DSUs. Directors are entitled to elect to receive their annual retainer, committee retainer, and/or committee chair retainer in full or partial DSUs. Directors will receive additional DSUs in respect of dividends payable on common shares of the Company based on the value of a DSU at that time. DSUs vest immediately and are redeemed for cash six months after a director's resignation from the Board, using the average closing price of the Company's common shares on the TSX for the five trading days immediately before the redemption date. During the year ended December 31, 2015, the Company recorded compensation expense of nil (2014 – $1 million) related to the outstanding DSUs in staff costs and employee benefits expense.

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

29. Financial instruments:

Fair values

The Company classifies its cash and cash equivalents as loans and receivables and measures them at amortized cost which approximates their fair values.

Trade and other receivables and current other financial assets are classified as loans and receivables; trade and other payables are classified as other financial liabilities; all of which are measured at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature.

Details of the Company's derivative instruments are described in note 14.

The classification, carrying amount and fair value of the Company's other financial instruments are summarized as follows:

		December 31, 2015		December 31, 2014	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets (note 16)					
Loans and receivables	Level 2	$ 12	$ 12	$ 16	$ 17
Finance lease receivable (note 15)					
Loans and receivables	Level 2	689	786	708	712
Loans and borrowings (note 22)					
Other financial liabilities (includes current portion)	Level 2	1,615	1,623	1,586	1,670
Finance lease obligation (note 15)					
Other financial liabilities (includes current portion)	Level 2	22	22	-	-

Loans and receivables

The fair values of the Company's finance lease receivables and other loans and receivables are estimated by discounting the expected future cash flows of these instruments at current market interest rates for comparable instruments with similar terms, plus an estimated credit spread based on the counterparty credit risk as at December 31, 2015 and 2014.

Other financial liabilities

The fair value of the Company's loans and borrowings and finance lease obligation is based on determining a current yield for the Company's loans and borrowings as at December 31, 2015 and 2014. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Company's loans and borrowings. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

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

29. Financial instruments, continued:

Offsetting of financial assets and liabilities

The Company's commodity trading transactions are typically transacted on an exchange or under International Swap Dealers Association (ISDA) Master Agreements or similar master agreements. In general, under the Company's trading agreements the amounts owed by each counterparty that are due on a single day in respect of all transactions outstanding in the same currency under the agreement are aggregated into a single net amount being payable by one party to the other. Such amounts meet the criteria for offsetting and are presented as such on the Company's statements of financial position. In certain circumstances, including when a credit event such as a default occurs, generally all outstanding transactions under the agreement are terminated, the termination value is assessed and only a single net amount is payable by one party to the other in settlement of all transactions. Amounts that may only be offset in these circumstances do not meet the criteria for offsetting on the Company's statements of financial position.

The Company also has an agreement in place with one of its energy trading counterparties that conveys to the counterparty the right to set-off amounts receivable and amounts payable between the Company and the counterparty in certain circumstances, including when a credit event such as a default occurs on the part of the Company. Such amounts do not meet the criteria for offsetting on the Company's statements of financial position.

The Company issues and accepts collateral in the form of cash and letters of credit in respect of its commodity trading transactions. Such collateral is generally subject to standard industry terms. The terms generally also give each counterparty the right to terminate the related transactions upon the other counterparty's failure to post collateral.

Financial assets subject to offsetting, enforceable master netting arrangements or similar arrangements

As at December 31, 2015

				Related amounts not offset in the statement of financial position		
Types of financial assets	Gross amounts of recognized financial assets	Gross amounts of recognized financial liabilities offset in the statement of financial position	Net amounts of financial assets presented in the statement of financial position [1]	Financial instruments	Collateral received [2]	Net amount
Commodity trading assets	$ 204	$ (9)	$ 195	$ (22)	$ (19)	$ 154

[1] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $93 million, non-current derivative instruments assets of $54 million and trade and other receivables of $48 million.

[2] Collateral received relating to the net financial assets disclosed above is in the form of letters of credit received from the Company's counterparties.

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

29. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

Financial liabilities subject to offsetting, enforceable master netting arrangements or similar arrangements

As at December 31, 2015

				Related amounts not offset in the statement of financial position		
Types of financial liabilities	Gross amounts of recognized financial liabilities	Gross amounts of recognized financial assets offset in the statement of financial position	Net amounts of financial liabilities presented in the statement of financial position [3]	Financial instruments	Collateral pledged	Net amount
Commodity trading liabilities	$ 71	$ (3)	$ 68	$ (28)	$ -	$ 40

[3] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $27 million, non-current derivative instruments liabilities of $15 million and trade and other payables of $26 million.

Financial assets subject to offsetting, enforceable master netting arrangements or similar arrangements

As at December 31, 2014

				Related amounts not offset in the statement of financial position		
Types of financial assets	Gross amounts of recognized financial assets	Gross amounts of recognized financial liabilities offset in the statement of financial position	Net amounts of financial assets presented in the statement of financial position [5]	Financial instruments	Collateral received [6]	Net amount
Commodity trading assets	$ 230	$ (10)	$ 220	$ (55)	$ (2)	$ 163

[4] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $107 million, non-current derivative instruments assets of $55 million and trade and other receivables of $58 million.

[5] Collateral received relating to the net financial assets disclosed above is in the form of letters of credit received from the Company's counterparties.

Financial liabilities subject to offsetting, enforceable master netting arrangements or similar arrangements

As at December 31, 2014

				Related amounts not offset in the statement of financial position		
Types of financial liabilities	Gross amounts of recognized financial liabilities	Gross amounts of recognized financial assets offset in the statement of financial position	Net amounts of financial liabilities presented in the statement of financial position [7]	Financial instruments	Collateral pledged [8]	Net amount
Commodity trading liabilities	$ 109	$ (10)	$ 99	$ (57)	$ (10)	$ 32

[6] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $59 million, non-current derivative instruments liabilities of $10 million and trade and other payables of $30 million.

[7] Collateral pledged against the net financial liabilities disclosed above consists of $9 million in cash collateral and $1 million in letters of credit issued.

30. Risk management:

Risk management overview

The Company is exposed to a number of different financial risks, arising from business activities and its use of financial instruments, including market risk, credit risk and liquidity risk. The Company's overall risk management process is designed to identify, manage and mitigate business risk which includes, among other risks, financial risk. Risk management is overseen by the Company's executive team according to objectives, targets, and policies approved by the Capital Power Board of Directors. The executive team is comprised of the most senior management group within the Company.

Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the Company's business objectives and risk tolerance. The Company's financial risk management objective is to protect and limit the volatility in income and cash flow.

Commodity price risk management and the associated credit risk management are carried out in accordance with the respective commodity, credit, and financial exposures risk management policies, as approved by the executive team and the Board of Directors. Financial risk management including foreign exchange risk, interest rate risk, liquidity risk, and the associated credit risk, is carried out by a centralized Treasury function, also in accordance with a financial risk management policy approved by the executive team and the Board of Directors. Capital Power's Audit Committee of the Board of Directors, in its oversight role, monitors the assessment of financial risk management controls and procedures to ensure compliance with applicable policies.

Market risk

Market risk is the risk of loss that results from changes in market factors such as commodity prices, foreign currency exchange rates, interest rates and equity prices. The level of market risk to which the Company is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Company's financial assets and liabilities held, non-trading physical asset and contract portfolios, and trading portfolios.

To manage the exposure related to changes in market risk, the Company uses various risk management techniques including derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps (or contracts-for-differences), and option contracts. Such derivative instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. Commodity risk exposures are monitored daily against approved risk limits, and control processes are in place to monitor that only authorized activities are undertaken.

The sensitivities provided in each of the following risk discussions disclose the effect of reasonably possible changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of income on these contracts. The Company's actual exposure to market risks is constantly changing as the Company's portfolio of debt, foreign currency and commodity contracts changes. Changes in fair values or cash flows based on market variable fluctuations cannot be extrapolated since the relationship between the change in the market variable and the change in fair value or cash flows may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Company.

Commodity price risk

The Company is exposed to commodity price risk as part of its normal business operations, including energy procurement activities in Alberta and the U.S. The Company's energy procurement activities consist of power generation, non-market traded and market traded electricity, natural gas purchase and sales contracts, and derivative contracts. The Company is primarily exposed to changes in the prices of electricity, and to a lesser extent is exposed to changes in the prices of natural gas and coal. The Company actively manages commodity price risk by optimizing its asset and contract portfolios utilizing the following methods:

30. Risk management, continued:

Market risk, continued

Commodity price risk, continued

- The Company reduces its exposure to the volatility of commodity prices related to electricity sales by entering into offsetting contracts such as contracts-for-differences and firm price physical contracts for periods of varying duration.
- The Company enters into fixed-price energy sales contracts and power purchase arrangements which limit the exposure to electricity prices. The Company has entered into long-term tolling arrangements whereby variable changes linked to the price of natural gas and coal are assumed by the counterparty.
- The Company enters into back-to-back electricity and natural gas physical and financial contracts in order to lock in a margin.

The Company also engages in taking market risk positions within authorized limits approved by Capital Power's executive team and Board of Directors. The trading portfolio consists of electricity and natural gas physical and financial derivative contracts which are transacted with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities.

The fair value of the Company's energy related derivatives as at December 31, 2015, that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 14.

The Company employs specific volumetric limits and a Value-at-Risk (VaR) methodology to manage risk exposures to commodity prices on a consolidated basis. VaR measures the estimated potential loss in a portfolio of positions associated with the movement of a commodity price for a specified time or holding period and a given confidence level. Capital Power's current period VaR uses a statistical confidence interval of 99% over a five business day holding period. This measure reflects a 1% probability that, over the five day period commencing with the point in time that the VaR is measured, the fair value of the overall commodity portfolio could decrease by an amount in excess of the VaR amount. The VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities and risk diversification by recognizing offsetting positions and correlations between products and markets. This technique makes use of historical data and makes an assessment of the market risk arising from possible future changes in commodity prices over the holding period.

VaR should be interpreted in light of the limitations of the methodologies used. These limitations include the following:

- VaR calculated based on a holding period may not fully capture the market risk of positions that cannot be liquidated or hedged within the holding period.
- The Company computes VaR of the portfolios at the close of business and positions may change substantially during the course of the day.
- VaR, at a 99% confidence level, does not reflect the extent of potential losses beyond that percentile. Losses on the other 1% of occasions could be substantially greater than the estimated VaR.

These limitations and the nature of the VaR measurements mean that the Company can neither guarantee that losses will not exceed the VaR amounts or that losses in excess of the VaR amounts will not occur more frequently than 1% of the time. As VaR is not a perfect predictor of risk, the Company undertakes back testing and periodically calibrates the VaR calculation to a 99% confidence level.

The estimation of VaR takes into account positions from all wholly-owned subsidiaries and subsidiaries in which the Company has a controlling interest, and reflects the Company's aggregate commodity positions from its trading and asset portfolios. Capital Power's Board of Directors has approved the methodology for the ongoing determination of commodity risk limits, under their commodity risk management policy. Commodity risk is monitored and reported to the executive team on a daily basis. The portfolios are stress tested regularly to observe the effects of plausible scenarios taking into account historical maximum volatilities and maximum observed price movements. Based on the commodity portfolio as at December 31, 2015, there is a 99% probability that unfavourable daily market variations would not reduce the fair value of the trading portfolio.

30. Risk management, continued:

Market risk, continued

Foreign exchange risk

The Company is exposed to foreign exchange risk on foreign currency denominated forecasted transactions, firm commitments, and monetary assets and liabilities denominated in a foreign currency and on its net investments in foreign operations. The Company's operations expose it to foreign exchange risk arising from transactions denominated in foreign currencies. The Company's foreign exchange risk arises primarily with respect to the U.S. dollar but it is potentially exposed to changes in other currencies if and when it transacts in other currencies. The risk is that the functional currency value of cash flows will vary as a result of the movements in exchange rates.

The Company's foreign exchange management policy is to limit economic and material transactional exposures arising from movements in the Canadian dollar relative to the U.S. dollar or other foreign currencies. The Company's exposure to foreign exchange risk arises from future anticipated cash flows from its U.S. operations, debt service obligations on U.S. dollar borrowings, and from certain capital expenditure commitments denominated in U.S. dollars or other foreign currencies. The Company co-ordinates and manages foreign exchange risk centrally, by identifying opportunities for naturally-occurring opposite movements and then dealing with any material residual foreign exchange risks; these are hereinafter referred to as being economically hedged. The Company may also use derivative instruments to manage foreign exchange risk. At December 31, 2015, the Company held foreign exchange derivatives as disclosed in note 14.

As at December 31, 2015, holding all other variables constant, a $0.10 strengthening or weakening of the Canadian dollar against the U.S. dollar would have increased or decreased net income attributable to shareholders by $5 million. There would be no impact to other comprehensive income.

This sensitivity analysis excludes translation risk associated with the translation of subsidiaries that have a different functional currency to the functional currency of the Company and financial instruments denominated in the functional currency in which they are transacted and measured.

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating rate current and non-current loans and borrowings. The Company is exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for current borrowings and other liquidity requirements. As at December 31, 2015, the proportion of fixed rate loans and borrowings was approximately 85% of total loans and borrowings outstanding (2014 - 99%). The Company may also use derivative instruments to manage interest rate risk. At December 31, 2015, the Company held interest rate derivatives as disclosed in note 14 which have effectively reduced the proportion of fixed rate loans and borrowing disclosed above to 67% (2014 – 86%).

Assuming that the amount and mix of fixed and floating rate loans and borrowings, net loans and borrowings and derivative instruments used to manage interest rate risk remains unchanged from that held as at December 31, 2015, a 100 basis point decrease or increase to interest rates would decrease or increase full year net income attributable to common shareholders by $12 million and would have no direct impact on other comprehensive income.

The effect on net income does not consider the effect of an overall change in economic activity that would accompany such an increase or decrease in interest rates.

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

30. Risk management, continued:

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Company. The Company's counterparty credit risk management policy is established by the executive team and approved by the Board of Directors. The associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the Company. Credit risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into any agreements or transactions with the counterparty. Credit exposures and concentrations are subsequently monitored and are regularly reported to management on an ongoing basis. Counterparty creditworthiness also continues to be evaluated on an ongoing basis after transactions have been initiated.

Credit risk is managed and mitigated through a number of risk mitigation practices such as securing parent company guarantees to enhance counterparty credit quality, negotiating and obtaining security (such as cash, letters of credit or property) to offset potential losses, utilization of credit derivatives to reduce credit risk and margining to limit credit risk where applicable.

Maximum credit risk exposure

The Company's maximum credit exposure was represented by the following financial assets:

As at December 31	2015	2014
Cash and cash equivalents	$ 80	$ 71
Trade and other receivables [1]	190	185
Derivative financial instruments assets [1]	220	187
Loans and other long-term receivables (note 16)	12	16
Finance lease receivables	689	708
	$ 1,191	$ 1,167

[1] The Company's maximum credit exposures related to trade and other receivables and derivative financial instruments assets by major credit concentration are comprised of maximum exposures of $241 million (2014 - $98 million) for generation counterparties and $169 million (2014 - $274 million) for wholesale counterparties at December 31, 2015.

This table does not take into account collateral held. As at December 31, 2015, the Company held cash deposits of nil (2014 - nil) as security for certain counterparty trade and other receivables and derivative contracts. The Company is not permitted to sell or re-pledge collateral in the absence of default of the collateral providers. As at December 31, 2015, the Company also held other forms of credit enhancement in the forms of letters of credit of $71 million (2014 - $55 million), property registrations valued at nil (2014 - $12 million) and parental guarantees of $1,301 million (2014 - $1,254 million) related to the financial assets noted above. As at December 31, 2015 and 2014, the Company also held parental guarantees which do not have a defined amount or limit, but which provide full support on any outstanding positions related to certain development projects and counterparty performance for power purchase arrangements.

30. Risk management, continued:

Credit risk, continued

Credit quality and concentrations

The Company is exposed to credit risk on outstanding trade and other receivables associated with its generation and optimization activities including power purchase arrangements, agreements with independent system operators, power and steam sales contracts, energy supply agreements with government sponsored entities, wholesale customers, and trading counterparties. The Company is also exposed to credit risk related to its cash and cash equivalents (which include short-term investments), financial and non-financial derivative instruments assets and long-term financing arrangements.

The credit quality and concentrations of the Company's trade and other receivables and other financial assets, by major credit concentrations are the following:

Cash and cash equivalents

The Company has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, are the primary counterparty of the Company's foreign exchange and interest rate derivative instruments, and facilitate letters of credit to mitigate the Company's exposure to certain counterparties. The Company manages its credit risk on cash and cash equivalents, and short-term investments by dealing with investment grade rated banks and financial institutions and reviewing each investment vehicle to ensure the underlying credit risk is known.

Loans and long-term financing

As at December 31, 2015, loans and long-term financing consists primarily of notes receivable attributable to two Alberta PPA syndicate members. The Company is exposed to credit risk in the event of non-performance by the syndicate members, but does not anticipate such non-performance. Although the syndicate members are not investment grade, the notes receivable are secured by security interests in the syndicate members' respective shares of the power syndicate agreement.

Trade and other receivables and financial derivative instruments

Trade and other receivables are substantially made up of receivables related to the generation and sale of electricity to customers including industrial and commercial customers, independent system operators from various regions and government-owned or sponsored entities and the settlement of financial derivative instruments related to merchant price risk mitigation and trading activities. The Company manages its credit risk on these financial assets through its credit adjudication process, dealing with creditworthy counterparties and utilizing the credit risk mitigation practices noted above.

Generation credit risk

Credit risk exposure from PPAs, agreements with independent system operators, power and steam sales contracts, and certain energy supply agreements is predominantly restricted to trade and other receivables and contract default. In certain cases, the Company relies on a single or small number of customers to purchase all or a significant portion of a facility's output. The failure of any one of these counterparties to fulfill its contractual obligations could negatively impact the Company's financial results. Financial loss resulting from events of default by counterparties in certain PPAs and steam purchase arrangements may not be recovered since the contracts may not be replaceable on similar terms under current market conditions. Consequently, the Company's financial performance depends on the continued performance by customers and suppliers of their obligations under these long-term agreements. Credit risk exposure is mitigated by dealing with creditworthy counterparties that are determined to be investment grade based on the Company's internally assigned ratings or employing mitigation strategies as noted above, netting amounts by legally enforceable set-off rights, and, when appropriate, taking back security from the counterparty. Credit risk with counterparties in this asset class that are government-owned or sponsored entities and regulated public utility distributors is generally considered low.

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

30. Risk management, continued:

Credit risk, continued

Wholesale and merchant credit risk

Credit risk exposure for wholesale and merchant trading counterparties is measured by calculating the costs (or proceeds) of replacing the commodity position (physical and derivative contracts), adjusting for settlement amounts due to or due from the counterparty and, if permitted, netting amounts by legally enforceable set-off rights. Financial loss on wholesale contracts could include, but is not limited to, the cost of replacing the obligation, amounts owing from the counterparty or any loss incurred on liability settlements. Wholesale and merchant credit risk exposure is mitigated by trading with investment grade and creditworthy counterparties, portfolio diversification, monitoring of credit exposure limits, margining to reduce energy trading risks, obtaining parent company guarantees, and when appropriate taking back security from counterparties.

Trade and other receivables and allowance for doubtful accounts

Trade and other receivables consist primarily of amounts due from customers including industrial and commercial customers, independent system operators from various regions, government-owned or sponsored entities, and other counterparties. Larger commercial and industrial customer contracts and contract-for-differences provide for performance assurances including letters of credit if deemed appropriate. The Company also has credit exposures to large suppliers of electricity and natural gas. The Company mitigates these exposures by dealing with creditworthy counterparties and, when appropriate, taking back appropriate security from the supplier.

The aging of trade and other receivables as at December 31, 2015 was:

	Gross trade and other receivables	Allowance for doubtful accounts	Net trade and other receivables
Current [2]	$ 190	$ -	$ 190
Outstanding 30 - 60 days	-	-	-
Outstanding 60 - 90 days	-	-	-
Outstanding greater than 90 days	5	(5)	-
	$ 195	$ (5)	$ 190

[2] Current amounts represent trade and other receivables outstanding zero to 30 days. Amounts outstanding more than 30 days are considered past due.

The changes in the allowance for doubtful accounts were as follows:

Year ended December 31	2015	2014
As at January 1	$ 5	$ -
Amounts reversed unused	-	-
New allowance	-	5
As at December 31	$ 5	$ 5

No bad debt expenses were recognized in the year (2014 - $5 million).

As at December 31, 2015, the Company held no customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers (2014 - nil).

As at December 31, 2015 and 2014, there were no provisions for credit losses associated with trade and other receivables from treasury, trading and energy procurement counterparties as all balances were considered to be fully collectible.

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

30. Risk management, continued:

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's liquidity is managed centrally by the Treasury function. The Company manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and also by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are addressed through a combination of committed and demand revolving credit facilities, financings in public and private capital debt markets and equity offerings by the Company or its CPLP subsidiary.

Capital Power has a long-term debt rating of BBB- (Outlook Stable) and BBB (Outlook Stable) assigned by Standard & Poor's (S&P) and DBRS Limited (DBRS) respectively. Capital Power has a preferred share rating of P-3 and Pfd-3(low) assigned by S&P and DBRS respectively. CPLP has long-term debt ratings of BBB- (Outlook Stable) and BBB/stable outlook assigned by S&P and DBRS respectively.

As at December 31, 2015, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $861 million (2014 - $1,086 million), of which $745 million is committed to 2020 (2014 - $1,061 million committed to 2018).

In addition to the facilities noted above, the Company has a shelf prospectus under which it may raise funds in the form of debt or equity. As at December 31, 2015, Capital Power has a Canadian shelf prospectus, which expires in January 2017, under which it may raise up to $3 billion collectively in common shares of the Company, preference shares of the Company, subscription receipts exchangeable for common shares and/or other securities of the Company, and debt securities of the Company. As at December 31, 2015, the amounts available on the shelf prospectus are $2,775 million (2014 - $3 billion).

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and where applicable, net of financial assets that generate cash inflows to meet cash outflows on financial liabilities as at December 31, 2015:

	Due within 1 year	Due between 1 and 2 years	2 and 3 years	3 and 4 years	4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Loans and borrowings	$ 154	$ 22	$ 184	$ 259	$ 546	$ 460	$ 1,625
Interest payments on loans and borrowings	51	43	39	33	28	57	251
Trade and other payables [3]	166	-	-	-	-	-	166
Finance lease obligation	1	1	2	2	2	14	22
Other current liabilities and deferred revenue	2	-	-	-	-	-	2
Derivative financial liabilities:							
Net commodity contracts for differences	15	5	-	-	-	-	20
Interest rate derivatives	11	-	-	-	-	-	11
Total	$ 400	$ 71	$ 225	$ 294	$ 576	$ 531	$ 2,097

[3] Excluding accrued interest on loans and borrowings of $14 million and current portion of finance lease obligation of $1 million.

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

31. Capital management:

The Company's primary objectives when managing capital are to safeguard the Company's ability to continue as a going concern, pay regular dividends to its shareholders, maintain a suitable credit rating, and to facilitate the acquisition or development of projects in Canada and the U.S. consistent with the growth strategy of the Company. The Company manages its capital structure in a manner consistent with the risk characteristics of the underlying assets.

The Company manages capital through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Company matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Company considers its capital structure to consist of loans and borrowings net of cash and cash equivalents and equity (which includes non-controlling interests).

The following table represents the total capital of the Company:

As at December 31	2015	2014
Loans and borrowings (note 22)	$ 1,615	$ 1,586
Finance lease obligation (note 15)	22	-
Cash and cash equivalents (note 11)	(80)	(71)
Net debt	1,557	1,515
Non-controlling interests (note 32)	68	552
Share capital (note 24)	2,744	2,391
Retained earnings and other reserves	4	60
Total equity	2,816	3,003
	$ 4,373	$ 4,518

CPLP has the following externally imposed requirements on its capital as a result of its credit facilities and certain debt covenants, as defined in the respective agreements:

- Maintenance of modified consolidated net tangible assets to consolidated net tangible assets ratio, as defined in the debt agreements, of not less than 0.8 to 1.0;
- Maintenance of senior debt to consolidated capitalization ratio, as defined in the debt agreements, of not more than 0.65 to 1.0;
- Limitation on debt issued by subsidiaries; and
- In the event that CPLP is assigned a rating of less than BBB- by S&P and BBB (Low) by DBRS, CPLP would also be required to maintain a ratio of net income before interest, income taxes, depreciation and amortization to finance expense, as defined in the debt agreements, of not less than 2.5 to 1.0.

For the year ended December 31, 2015, CPLP complied with all externally imposed capital restrictions. Effective January 2016, amendments made to the loan credit agreements will require Capital Power to meet the financial covenants referenced above in place of CPLP.

To manage or adjust its capital structure, the Company can issue new loans and borrowings, issue common or preferred shares, buy back common shares, redeem preferred shares, issue new CPLP units, repay existing loans and borrowings or adjust dividends paid to its shareholders.

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

32. Investments in subsidiaries that have non-controlling interests:

Set out below are the Company's principal subsidiaries that have non-controlling interests (NCI) at December 31, 2015:

	Place of business	Percentage of ownership interest held by the Company	Percentage of ownership interest held by the NCI	Principal activities
CPLP [1]	Canadian partnership with Canadian and U.S. subsidiaries	100%	0%	Power generation
Genesee Coal Mine Assets (Coal Mine) [2]	Canada	50%	50%	Coal production for use in power generation

[1] On April 2, 2015, EPCOR exchanged all 18.841 million of its exchangeable limited partnership units of CPLP on a one-for-one basis for common shares of Capital Power in accordance with the terms of the exchangeable common limited partnership units. As a result of the unit exchange, EPCOR's ownership interest in CPLP was reduced to nil (December 31, 2014 – 18%) and Capital Power's interest in CPLP increased to 100% (December 31, 2014 – 82%).

[2] The Company holds a 50% interest in the Coal Mine while the other 50% is held by a third party. The decisions about the relevant activities of the coal mine are made based on majority vote by the Management Committee. The Management Committee is comprised of three members appointed by each of the Company and the third party. Based on the terms of the agreement surrounding the operations of the Coal Mine, it is noted that under the circumstance where the two parties are in a deadlock with respect to a decision that would affect the relevant activities of the Coal Mine, Capital Power holds the deciding vote. Given Capital Power's voting rights, Capital Power has control to affect the variability in its returns. Based on an assessment of the relationship between Capital Power and the Coal Mine, Capital Power controls the Coal Mine and therefore the Coal Mine is treated as a subsidiary of Capital Power.

There are no significant restrictions on access to a subsidiary's assets that relate to the subsidiaries above, other than those described in note 31.

The summarized financial information of CPLP and the Coal Mine is as follows:

	2015		2014	
Consolidated statements of financial position	CPLP	Coal Mine	CPLP	Coal Mine
Current assets	$ 607	$ -	$ 487	$ -
Non-current assets	4,887	136	4,956	142
Current liabilities	(572)	-	(877)	-
Non-current liabilities	(2,068)	-	(1,732)	-
Non-controlling interests - Genesee Coal Mine	(68)	-	(72)	-
Non-controlling interests - other	(22)	-	(19)	-
Net assets	$ 2,764	$ 136	$ 2,743	$ 142

	2015		2014	
Consolidated statements of income	CPLP	Coal Mine	CPLP	Coal Mine
Revenues	$ 1,245	$ -	$ 1,220	$ -
Net income (loss) attributable to partners	120	(19)	73	(22)
Other comprehensive income attributable to partners	46	-	52	-
Total comprehensive income (loss) attributable to partners	$ 166	$ (19)	$ 125	$ (22)

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

32. Investments in subsidiaries that have non-controlling interests, continued:

	2015		2014	
Consolidated statements of cash flows	CPLP	Coal Mine	CPLP	Coal Mine
Net cash flows from operating activities	$ 306	$ -	$ 336	$ -
Net cash flows used in investing activities	(132)	(13)	(227)	(8)
Net cash flows (used in) from financing activities	(168)	13	(141)	8
Foreign exchange gain on cash held in a foreign currency	6	-	1	-
Net increase (decrease) in cash and cash equivalents	12	-	(31)	-
Cash and cash equivalents at beginning of year	69	-	100	-
Cash and cash equivalents at end of year	$ 81	$ -	$ 69	$ -

Non-controlling interests reflected on the consolidated balance sheet are comprised of:

Year ended December 31	2015	2014
Non-controlling interest in CPLP, beginning of year	$ 480	$ 509
Net income attributable to non-controlling interest	6	15
Other comprehensive income attributable to non-controlling interest	2	10
Distributions to non-controlling interest (note 27)	(6)	(25)
Change in non-controlling interest ownership	-	(29)
Exchange of CPLP units for Capital Power shares	(482)	-
Non-controlling interest in CPLP, end of year	-	480
Non-controlling interest in Genesee Coal Mine, beginning of year	72	78
Net loss attributable to non-controlling interest	(10)	(11)
Net additional investment by non-controlling interest	6	5
Non-controlling interest in Genesee Coal Mine, end of year	68	72
	$ 68	$ 552

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

33. Interests in joint arrangements:

Joint operations

The Company holds interests in the following joint operations as at December 31, 2015:

	Place of business	% of ownership interest
Genesee (G3) Project [1]	Canada	50%
Keephills 3 (K3) Project [2]	Canada	50%
Joffre Cogeneration Project [3]	Canada	40%
Shepard Energy Centre (Shepard) [4]	Canada	50%
Genesee 4 and 5 [5]	Canada	50%

[1] G3 is a 516MW coal-fired generating facility and is a 50/50 joint arrangement between Capital Power and a third party, with Capital Power acting as the manager and operator. Both parties independently dispatch and market their share of the electrical output through Alberta's competitive wholesale market.

[2] K3 is a 516MW coal-fired generating facility and is a 50/50 joint arrangement between Capital Power and a third party with the third party responsible for operations. Both parties independently dispatch and market their share of the facility's electrical output through Alberta's competitive wholesale market.

[3] Joffre Cogeneration Project is a 480MW gas-fired combined cycle cogeneration facility in which Capital Power holds a 40% interest with third parties holding 40% and 20% interests, respectively. The Company's investment in the Joffre Cogeneration Project joint arrangement, which is incorporated as a separate legal entity, has been determined to be a joint operation since the contractual arrangements governing the joint arrangement indicate that the parties to the arrangement are entitled to the assets of the joint arrangement and are exposed to the liabilities of the joint arrangement in proportion to their ownership interest.

[4] Shepard is an 800MW gas-fired generating facility which is a 50/50 joint arrangement between Capital Power and a third party with the third party responsible for operations. Both parties independently dispatch and market their share of the electrical output through Alberta's competitive wholesale market.

[5] Genesee 4 and 5 is a 1,060MW gas-fired generating project and is a 50/50 joint arrangement between Capital Power and a third party, with Capital Power responsible for construction and operations of the project. Regulatory approvals have been received. The Company's commitments associated with Genesee 4 and 5 are described in note 34(b).

There are no significant restrictions pertaining to the joint operations described above, other than those described in note 22 pertaining to the charges on the Joffre Cogeneration project assets.

Joint ventures

The Company holds an interest in the following joint venture as at December 31, 2015:

	Place of business	Measurement Method
K2 Wind Power Project (K2 Wind)[6]	Canada	Equity method

[6] K2 Wind is a 270MW wind facility in which Capital Power holds an equal 33.33% interest with two other third parties. The Company's investment in K2 Wind, which consists of separate legal entities, has been determined to be a joint venture. The Company's obligations are limited to their capital contributions to the joint arrangement, and the Company's receipts of the economic benefits of the joint arrangement are limited to annual distributions. As a result, there is no indication that the Company has rights to the assets or obligations for the liabilities of the joint arrangement and the investment has been classified as a joint venture.

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

33. Interests in joint arrangements, continued:

Joint ventures, continued

The summarized financial information of K2 Wind is as follows:

Statements of Financial Position	2015	2014
Cash and cash equivalents	$ 39	$ 1
Other current assets[7]	25	40
Non-current assets [7]	875	756
Financial current liabilities	(46)	-
Other current liabilities	(19)	(76)
Financial non-current liabilities	(850)	(646)
Other non-current liabilities	(16)	(10)
Net assets	$ 8	$ 65

[7] K2 Wind has restricted cash of $20 million included in other current and non-current assets above (2014 - $28 million in non-current assets) which represents security for a standby line of credit with a third party.

Statements of Income (Loss) and Comprehensive Loss	2015	2014
Revenues	$ 75	$ -
Other raw materials and operating charges	(6)	-
Other administrative expense	(10)	-
Depreciation and amortization	(21)	-
Finance expense	(15)	-
Net income (loss)	23	(1)
Other comprehensive loss:		
Unrealized losses on derivative instruments	(32)	(60)
Total comprehensive loss	$ (9)	$ (61)

A reconciliation of the Company's recorded equity investment in K2 Wind is as follows:

As at December 31	2015	2014
Opening balance	$ 22	$ 15
Proportionate share of comprehensive loss (33.33%)	(3)	(20)
Distributions received – return of capital	(8)	-
Distributions received – operating	(8)	-
Contributions paid	-	27
Adjustments for differences in accounting policies	7	-
	$ 10	$ 22

34. Commitments and contingencies:

(a) Under the terms of the Sundance PPA, the Company is obligated to make monthly payments for fixed and variable costs. The estimated annual total of these payments for 2016 is $99 million. It is expected that the annual payments over the remaining term of the Sundance PPA, as described in note 18, will range from $99 million to $146 million, adjusted for inflation, other than in the event of a forced outage. The actual amounts for future years may vary from estimates depending on generation volume, scheduled outages, and force majeure events.

(b) The Company is party to a series of agreements with a third party to develop, build and own a 50% interest in Genesee 4 and 5 located in central Alberta. The Company expects to invest approximately $820 million, including capitalized borrowing costs, into Genesee 4 and 5, which are expected to commence commercial operations as early as 2020 and 2021 respectively, contingent on compensation the Company will receive for the projected accelerated closure of coal-fired generating units in Alberta, the implementation of the CLP not having adverse impacts to the Alberta electricity market design and upon price signals from the energy only market. It is expected that the two parties will build, own and operate Genesee 4 and 5, which would operate as a joint arrangement. In conjunction with the joint arrangement, the parties would be subject to various commercial agreements, including an eight year tolling agreement. Under the tolling agreement, 50% of Capital Power's share of the output will be sold to the other party to the joint arrangement starting in 2021.

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

34. Commitments and contingencies, continued:

(c) The Company is party to a number of long-term energy purchase and transportation contracts, operating and maintenance contracts, contracts to purchase environmental credits and operating leases for premises in the normal course of operations. Some of the energy purchase and transportation contracts are measured at their fair value and recorded on the consolidated statement of financial position as derivative financial instruments assets and liabilities as appropriate. The energy purchase and transportation contract amounts disclosed below are based on gross settlement amounts.

Approximate future payments under each group of contracts are as follows:

	Energy purchase and transportation contracts	Operating and maintenance contracts	Environmental credits	Operating leases
Within one year	$ 105	$ 22	$ 39	$ 8
Between one and five years	286	89	62	32
After five years	433	206	6	65
	$ 824	$ 317	$ 107	$ 105

(d) The Company 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, among other things, the loss factors to be applied for the years 2006 forward and is expected to be completed in three modules. In January 2015, the AUC issued its decision in Module A of the proceeding and concluded that it has the jurisdiction and authority to retroactively apply loss factors resulting from a new LLR. Module A was subsequently appealed by numerous parties, including the Company. Principles for the new LLR were considered in Module B and in November 2015, the AUC issued a decision in which it directed the AESO to make several changes to the currently non-compliant LLR including that it be based on an incremental loss factor methodology. The AUC also directed the AESO to file a plan and timeline for a revised LLR incorporating this new methodology and on February 1, 2016, the AESO indicated that it will work to develop and implement the new LLR by January 1, 2017. Module C of the LLR Proceeding will address the compensation to be paid or received by the various parties. As at February 18, 2016, no retroactive loss factors have been produced by the AESO using the new LLR nor has any 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 is unknown. Capital Power may incur material additional transmission charges on a retrospective and go-forward basis but a provision has not been recorded in the Company's audited consolidated financial statements since the outcome of the proceeding is not known.

(e) The Company has contingent consideration payable upon reaching specified milestones in connection with the development sites acquired in connection with the its acquisition of Element in 2014. As at December 31, 2015, contingent consideration of $13 million (US$9 million) is recorded in non-current other liabilities. The valuation model for contingent consideration is based on the present value of the expected payment discounted using a risk-adjusted discount rate of 8%. The expected payment is determined by considering the possible scenarios for the development sites reaching specified milestones, the amount to be paid under each scenario and the probability of each scenario.

(f) 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.

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

35. Guarantees:

The Company, through its subsidiary CPLP, has issued letters of credit of $125 million (2014 - $122 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

36. 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:

	Year ended December 31, 2015				Year ended December 31, 2014			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 1,125	$ 126	$ -	$1,251	$1,061	$ 167	$ -	$1,228
Revenues - inter-area	9	12	(21)	-	17	1	(18)	-
Total revenues	$ 1,134	$ 138	$ (21)	$1,251	$1,078	$ 168	$ (18)	$1,228

	As at December 31, 2015			As at December 31, 2014		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,452	$ 227	$ 3,679	$ 3,511	$ 190	$ 3,701
Intangible assets	300	41	341	313	37	350
Goodwill	-	30	30	-	25	25
Other assets	22	2	24	28	-	28
	$ 3,774	$ 300	$ 4,074	$ 3,852	$ 252	$ 4,104

37. Comparative figures:

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