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For release: February 28, 2014

Capital Power reports fourth quarter and strong year-end 2013 results

Company exceeds its 2013 financial targets

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released strong financial results for the fourth quarter and year ended December 31, 2013.

Funds from operations were $109 million in the fourth quarter of 2013, an increase of 31% from $83 million in the fourth quarter of 2012. Cash flow per share for the quarter was $1.11 compared with $0.84 for the same quarter in the previous year. Normalized earnings attributable to common shareholders in the fourth quarter of 2013 were $28 million, or $0.35 per share, compared with $16 million, or $0.23 per share, in the comparable period of 2012. Net income attributable to shareholders in the fourth quarter of 2013 was $77 million and basic earnings per share were $0.89 compared with net income attributable to shareholders of $15 million and basic earnings per share of $0.19 in the comparable period of 2012.

For the year ended December 31, 2013, funds from operations totaled $419 million compared with $381 million for the year ended December 31, 2012. Cash flow per share for 2013 was $4.24 compared with $3.89 for 2012. Normalized earnings attributable to common shareholders were $123 million or $1.69 per share compared with $86 million or $1.29 per share for 2012. Net income attributable to shareholders in 2013 was $175 million and basic earnings per share were $2.13 compared with net income attributable to shareholders of $62 million and basic earnings per share of $0.84 in 2012.

"Capital Power's fourth quarter financial results highlighted the strong cash flow that is being produced by the Company's modern fleet of power generation facilities," said Brian Vaasjo, President and CEO of Capital Power. The 105-megawatt Port Dover and Nanticoke wind project in Ontario was added to our fleet when it began commercial operations in the fourth quarter and was the third wind project added to the fleet over the past 16 months. With production largely contracted, these wind projects are contributing to our growing contracted cash flow profile, which is expected to improve further when the Shepard Energy Centre and K2 Wind projects are completed by 2015."

"For the full 2013 year, our financial results benefited from higher Alberta spot power prices that averaged $80 per megawatt hour compared to our forecast assumption of $58 per megawatt hour which enabled us to exceed all our annual financial targets," said Mr. Vaasjo. "This included cash flow and normalized earnings per share measures which increased 9% and 31%, respectively, compared with 2012. With Alberta power prices currently forecasted in the mid-$50 per megawatt hour for 2014, we are on track to achieve our funds from operations target for this year."

Operational and Financial Highlights [1] (unaudited)	**Three months ended December 31**		**Year ended December 31**	
(millions of dollars except per share and operational amounts)	**2013**	**2012**	**2013**	**2012**
Electricity generation (excluding acquired Sundance PPA) (GWh)	3,925	4,159	16,130	16,455
Generation plant availability (excluding acquired Sundance PPA) (%)	93%	89%	93%	91%
Revenues	$ 327	$ 288	$ 1,393	$ 1,296
Adjusted EBITDA [2]	$ 119	$ 73	$ 509	$ 441
Net income	$ 98	$ 19	$ 228	$ 90
Net income attributable to shareholders of the Company	$ 77	$ 15	$ 175	$ 62
Normalized earnings attributable to common shareholders [2]	$ 28	$ 16	$ 123	$ 86
Basic earnings per share	$ 0.89	$ 0.19	$ 2.13	$ 0.84
Diluted earnings per share	$ 0.89	$ 0.19	$ 2.08	$ 0.84
Normalized earnings per share [2]	$ 0.35	$ 0.23	$ 1.69	$ 1.29
Funds from operations [2]	$ 109	$ 83	$ 419	$ 381
Cash flow per share [2]	$ 1.11	$ 0.84	$ 4.24	$ 3.89
Purchase of property, plant and equipment and other assets	$ 59	$ 165	$ 943	$ 598
Discretionary cash flow [2]	$ 61	$ 12	$ 195	$ 132
Dividends per common share, declared	$ 0.315	$ 0.315	$ 1.26	$ 1.26

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, 2013.

2 Earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses, and gains on disposals (adjusted EBITDA), normalized earnings attributable to common shareholders, normalized earnings per share, funds from operations, cash flow per share, and discretionary cash flow 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

Sale of North East U.S. subsidiaries and refocusing of business

On November 19, 2013, Capital Power completed the sale of 100% of its equity interests in the entities that own the three North East U.S. combined cycle, natural gas-fired power generation facilities (the North East U.S. assets). The sale to Emera Inc. was for proceeds of $576 million (US$549 million) less transaction costs of $8 million (US$8 million). The Company recorded a pre-tax impairment loss of $6 million in the third quarter of 2013 and a pre-tax gain on disposal of $76 million primarily consisting of accumulated foreign currency translation gains related to these North East U.S. foreign subsidiaries.

The Company incurred pre-tax restructuring costs of approximately $13 million as a result of its decision to exit the North East U.S. market and to refocus its merchant power business in Alberta including the elimination of trading desk operations outside of Alberta. Future expected impacts include lower spending due to efficiencies in operations and maintenance while approximately 160 employee positions were eliminated by the end of 2013 resulting in approximately 700 active employee positions at the beginning of 2014.The expected annual cost savings are $25 million to $30 million consisting of an estimated $22 million related to general and administration (including support services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management, and environment, health and safety) and $8 million related to operations. The estimated cost savings primarily consist of employee compensation including benefits less margins from the discontinued trading operations.

Port Dover and Nanticoke facility begins commercial operations

On November 7, 2013, the Port Dover and Nanticoke wind project in Ontario began commercial operations. The 105 megawatt (MW) wind facility was completed on time and under its $340 million budget, with final construction costs expected to be approximately $300 million. This is 12% lower than budget primarily due to strong project management including the impact of up-front planning and project execution steps such as value engineering, constructability improvements and supply chain optimization. The Port Dover and Nanticoke wind project was awarded a 20-year power purchase agreement with the Ontario Power Authority (OPA), as part of the OPA's Feed-in-Tariff program. The contracted price for power at commercial operations is $144 per megawatt hour and thereafter, 20% of the contract price will escalate annually at inflation throughout the 20-year term.

Secondary offering of Capital Power common shares by EPCOR

On October 10, 2013, EPCOR exchanged 9,600,000 of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9,600,000 common shares of Capital Power to the public pursuant to a secondary offering at $21.00 per common share. Capital Power did not receive any of the proceeds from EPCOR's sale of common shares. These transactions reduced EPCOR's ownership interest in CPLP to approximately 19% from its interest of approximately 29% at September 30, 2013 and reduced EPCOR's ownership of the common shares of Capital Power, on a diluted basis, to 19% from 29%. 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, its requirements for capital and other circumstances that may arise in the future.

EPCOR's ownership interest in the limited partnership units of CPLP dropped below 20% as a result of these transactions. Thus, the terms of the agreement for the debt payable to EPCOR provide that EPCOR may, by advance written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon. The debt payable to EPCOR at December 31, 2013 was $341 million. Also, EPCOR may only elect two of Capital Power's directors compared to four previously.

Purchase of interest in Shepard Energy Centre and development of Genesee 4 & 5

The Company entered into a series of agreements with ENMAX Corporation (ENMAX) to purchase a 50% interest in the 800-MW natural-gas-fuelled Shepard Energy Centre (Shepard) located on the eastern limits of the City of Calgary. Shepard is expected to begin commercial operations in the first quarter of 2015. On February 28, 2013 and September 30, 2013, respectively, the purchases of the first and second tranches of the Company's interest in Shepard closed. Upon close of the first tranche, the Company paid $237 million and acquired a 25% interest in Shepard. Upon close of the second tranche, the Company paid an additional $325 million and acquired an additional 25% interest in Shepard bringing the Company's total ownership interest to 50%. The total amount incurred by the Company to the date of close of the second tranche was $649 million compared with the total anticipated capital cost of $821 million. Commencing with the close of the first tranche, all decisions related to Shepard require unanimous approval by the Company and ENMAX. As a result, the Company jointly controls Shepard with ENMAX upon close of the first tranche. Based on the terms of the Shepard agreements, the Company will account for the Shepard joint arrangement as a joint operation.

In the fourth quarter of 2013, Capital Power and ENMAX announced their letter of intent to pursue joint arrangement agreements to develop, construct, own and operate the Genesee 4 & 5 facility (formerly Capital Power Energy Centre).

$200 million offering of 4.50% Cumulative Rate Reset Preference Shares

On March 14, 2013, Capital Power Corporation issued 8 million Cumulative Rate Reset Preference Shares, Series 5 (Series 5 Shares) at $25 per share for aggregate gross proceeds of $200 million on a bought deal basis with a syndicate of underwriters.

The Series 5 Shares will pay fixed cumulative preferential dividends of $1.125 per share per annum, yielding 4.50% per annum, payable on the last business day of March, June, September and December each year, as and when declared by the Board of Directors of Capital Power Corporation. These dividends are applicable for the initial period ending June 30, 2018. The Series 5 Shares are subject to specified redemption, conversion and reset rights.

Standard & Poor's (a division of the McGraw Hill Companies, Inc.) (S&P) assigned a rating of P-3 and DBRS Limited (DBRS) assigned a rating of Pfd-3 (low) for the Series 5 Shares.

Subsequent Event

Sundance force majeure claim settlement

In July 2012, the Sundance plant owner made a force majeure claim for $39 million with respect to the 2011 third quarter outage of Unit 6 due to a transformer failure. The Company has a 52% interest in the Sundance acquired PPA for Units 5 and 6 and thus was contractually responsible for paying its share of the claimed amount in advance of final determination of whether or not a force majeure situation, as specified in the PPA, occurred. Accordingly, Capital Power paid its share of the claimed amount and, based on the Company's view that the claim would not meet the PPA specified force majeure tests, recorded it as an amount receivable until final resolution of the claim. The claim was under arbitration but the Company entered into settlement negotiations with the plant owner. At the time of payment in 2012, the Company recorded its $20 million payment as an amount receivable included in other financial assets. Based on the analysis performed in preparation for the arbitration and potential settlement with the plant owner, the Company reduced the amount receivable to $10 million in the fourth quarter of 2013. In February 2014, the Company reached a settlement with the plant owner and will receive payments consistent with the revised amount receivable. The settlement also resolves a 2012 dispute relating to Index 9 of the PPA with immaterial consequences to the Company.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on March 3, 2014 at 11:00 AM (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 1149970# followed by participant code 21543#. The replay will be available until midnight on April 1, 2014.

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 conference call.

Non-GAAP Financial Measures

The Company uses (i) adjusted EBITDA, (ii) funds from operations, (iii) cash flow per share, (iv) discretionary cash flow, (vi) normalized earnings attributable to common shareholders, and (vi) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and are, therefore, unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to gross income, net income, net income attributable of 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 gross income, operating income and 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 dated February 28, 2014 for the year ended December 31, 2013 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 information with respect to expectations regarding: (i) future cash flows, (ii) completion of capital projects, and (iii) the impact of refocusing the Company's merchant power business including cost savings.

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 and 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 expenditures, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's Management's Discussion and Analysis dated February 28, 2013 for further discussion of these and other risks.

For more information, please contact:

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Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated February 28, 2014, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the years ended December 31, 2013 and December 31, 2012, the annual information form of Capital Power Corporation for the year ended December 31, 2013 and the cautionary statements regarding forward-looking information which begins on page 3. 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, 2013, 2012 and 2011 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 28, 2014.

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Material forward-looking information in this MD&A includes information with respect to: (i) expectations related to future revenues, expenses, earnings and funds from operations, (ii) expectations regarding the future pricing of electricity and market fundamentals in existing and target markets, (iii) expectations related to the Company's future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions, (iv) expectations regarding the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings, (v) expectations regarding future growth and emerging opportunities in the Company's target markets including the focus on certain technologies, (vi) expectations regarding the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions, (vii) expectations regarding plant availability, (viii) expectations regarding the refocusing of the Company's merchant power business, and (ix) expectations regarding capital expenditures for plant maintenance and other.

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 and 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 of and impact of policy, legislation and regulations, (v) effective tax rates, and (vi) other matters discussed under the Performance Overview and Outlook sections.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are: (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 expenditures, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, and (viii) 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 2,600 megawatts (MW) of power generation capacity at 14 facilities across North America and owns 371 MW of capacity through its interest in the acquired Sundance power purchase arrangement (acquired Sundance PPA). An additional 490 MW of owned generation capacity is under construction in Alberta and Ontario.

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, 2013, the Company held 21.750 million general partnership units and 56.299 million common limited partnership units of CPLP which represented approximately 81% of CPLP's total partnership units. EPCOR (in this MD&A, EPCOR refers to EPCOR Utilities Inc. collectively with its subsidiaries) held 18.841 million exchangeable common limited partnership units of CPLP which represented approximately 19% of CPLP. CPLP's exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis.

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 business strategy that sets out how to become an increasingly competitive power producer and financial strategy that is 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.

- **Geographic focus** – Canada and the U.S. for contracted power generation and Alberta for merchant power generation.
- **Technology focus** – large-scale fossil fuel fired technologies supplemented by renewable wind and solar facilities with a limited number of technologies and suppliers for each type of generation.
- **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.
- **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.
- **Disciplined growth** – restricted to the geographic and technology focuses with specific financial hurdles and rigorous due diligence processes.

In November 2013, Capital Power completed the sale of its North East U.S. assets and reinforced its intention to focus its merchant power activities entirely in Alberta. The refocusing of merchant power business in Alberta included a number of direct and indirect cost saving initiatives creating a leaner, more focused business with lower risk. The Company will continue to strive to create additional value in the Alberta market through portfolio trading strategies.

The Company continues to pursue growth in contracted power generation across North America. During the year ended December 31, 2013, the Company purchased a 50% ownership interest in Shepard Energy Centre in two tranches, commenced commercial operations of the Port Dover and Nanticoke wind project, continued development of the K2 wind project and continued the process of planning for the development of Genesee 4 & 5 (see Significant Events). The Company also implemented a redesigned Enterprise Resource Planning system to support its strategic objectives.

The Company has a number of other projects in various stages of development and it continues to evaluate acquisition prospects to strengthen its regional footprint and existing portfolio. To help ensure that the Company's financial condition is not compromised by its growth strategy, it has set internal rates of return targets for acquisition and development project opportunities. As part of the Company's growth strategy through developing and building new assets, the Company has chosen to make construction 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. 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	2013 target	2013 actual results
Plant availability average [1]	93% or greater	93%
Capital expenditures for plant maintenance, Genesee mine extension and other (sustaining capital expenditures)	$105 million or lower	$79 million
Plant operating and maintenance expenses	$225 million to $245 million	$192 million

3 All plants excluding acquired Sundance PPA.

In 2013, the Company's plant availability averaged 93% which reflected major scheduled maintenance outages for Genesee 1 and Keephills 3 that were completed during the quarter ended June 30, 2013. Additionally, the plant availability average for the first three quarters of 2013 reflected unscheduled second quarter outages at Genesee 1 and 2 while Tiverton, in the North East U.S., experienced an outage in the first quarter of 2013 when the maintenance work that was originally scheduled to be performed in the last half of 2013 was completed.

Capital expenditures for 2013 for maintenance of the plants, Genesee mine extension and other were lower than target primarily due to sustaining capital expenditures related to the North East U.S. assets which were sold in the fourth quarter of 2013 (see Significant Events). These expenditures were incurred and charged to the purchaser of the North East U.S. assets before classification as additions to property, plant and equipment. The deferral of certain project expenditures from 2013 to 2014 also resulted in lower total sustaining capital expenditures compared with target.

The plant operating and maintenance expenses target includes other raw materials and operating charges, staff costs and employee benefits expense and other administrative expenses for the Company's plants. The actual results for 2013 were significantly less than target primarily because of certain expenses included in the target that were subsequently reclassified and reported as energy purchases and fuel. If the target had been adjusted for the reclassified amounts, it would have been approximately $190 million to $210 million. Thus, plant operating and maintenance expenses were in line with target but were impacted by the offsetting factors of increased costs due to the refocusing of the business and decreased costs due to the Company's continued focus on cost optimization and efficiency.

Disciplined growth

Performance measure	2013 target	Status as at December 31, 2013
Port Dover and Nanticoke wind project	Continue on budget of $340 million and on time with commercial operation date in the fourth quarter of 2013	Achieved commercial operation date on November 7, 2013 with final capital costs forecast to be $300 million
K2 wind project	Environmental approvals received in 2013	Environmental approvals were received in July 2013
Shepard Energy Centre	Continue on budget of $860 million	On track with revised budget of $821 million

The Port Dover and Nanticoke wind project was completed on time and under budget in the fourth quarter of 2013. The total project costs are expected to be approximately $300 million after all capital costs are incurred including certain post commercial operations date capital expenditures. This is 12% lower than budget primarily due to strong project management including the impact of up-front planning and project execution steps such as value engineering, constructability improvements and supply chain optimization.

The Company's budget for Shepard Energy Centre has been revised to $821 million from the previously disclosed $860 million primarily due to the reduction of expected construction costs and associated capitalized interest.

Financial stability and strength

Performance measure	2013 target	2013 actual results
Normalized earnings per share [1]	$1.20 to $1.40	$1.69
Funds from operations [1]	$385 million to $415 million	$419 million
Cash flow per share [1]	$3.80 to $4.20	$4.24

1 Normalized earnings per share, funds from operations, and cash flow per share are non-GAAP measures. See Non-GAAP Financial Measures.

Actual financial results achieved in 2013 compared with the 2013 financial targets reflected the overall impact of higher than expected power prices. The target was based upon an expected average Alberta power price of $58 per megawatt hour (MWh) while the actual average Alberta power price was $80 per MWh.

Outlook and Targets for 2014

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. Based upon a forecast average Alberta power price of approximately $57 per megawatt hour (MWh), funds from operations for 2014 are expected to be less than 2013 funds from operations. Items impacting the year-over-year comparison are discussed below.

The Company's forecast for average Alberta power prices in 2014 of $57 per MWh is lower than the average of $80 per MWh experienced in 2013. Thus, the Company expects lower realized prices on its economically unhedged position, profitability from the peaking facilities, and incentive revenues from Genesee 1 and 2. This is expected to be offset by the full year earnings from Port Dover and Nanticoke and stronger plant availability. In 2014, Capital Power's availability target of 95% reflects major scheduled maintenance outages for Genesee 2, Genesee 3 and Joffre, compared with the 2013 major scheduled maintenance outages for Genesee 1 and Keephills 3.

Portfolio positions (based on the generation from the baseload plants and acquired Sundance PPA in the Alberta commercial portfolio) for 2013 (as at the beginning of the year) compared with 2014, 2015 and 2016 (all as at December 31, 2013) were:

Alberta commercial portfolio positions and power prices	2013	2014	2015	2016
Percentage of baseload generation sold forward	49%	100%	78%	30%
Contracted price [1]	Mid-$60 per MWh	Mid-$50 per MWh	Mid-$50 per MWh	Mid-$50 per MWh

[1] 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. This impact is accentuated in 2014 which includes one contract-for-differences for 300 MW for the full year that is sold forward for peak periods only.

The 2014 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.

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

Performance measure targets for 2014

Performance measure	2014 target
Operational excellence	
Plant availability average	95% or greater
Capital expenditures for plant maintenance, Genesee mine extension and other (sustaining capital expenditures)	$85 million
Plant operating and maintenance expenses	$165 million to $185 million
Disciplined growth	
K2 wind project	Commence construction and complete project financing
Shepard Energy Centre	Complete construction with commercial operation date in early 2015
Genesee 4 & 5	Continue on track for first quarter 2015 permitting approval
Financial stability and strength	
Funds from operations [1]	$360 million to $400 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, and gains on disposals (adjusted EBITDA), (ii) funds from operations, (iii) cash flow per share, (iv) discretionary cash flow, (v) normalized earnings attributable to common shareholders, and (vi) normalized earnings per share as financial performance measures.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and are therefore unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective.

Adjusted EBITDA

Capital Power uses adjusted EBITDA to measure the operating performance of plants and categories of plants from period to period. Management believes that a measure of plant operating performance is more meaningful if results not related to plant operations such as impairments, foreign exchange gains or losses and gains 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							
	2013	**2012**	**Dec 2013**	**Sep 2013**	**Jun 2013**	**Mar 2013**	**Dec 2012**	**Sep 2012**	**Jun 2012**	**Mar 2012**
Revenues	1,393	1,296	327	380	321	365	288	387	253	368
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expenses	(884)	(855)	(208)	(229)	(217)	(230)	(215)	(236)	(188)	(216)
Adjusted EBITDA	**509**	**441**	**119**	**151**	**104**	**135**	**73**	**151**	**65**	**152**
Depreciation and amortization	(222)	(221)	(52)	(54)	(58)	(58)	(62)	(52)	(53)	(54)
Impairments	(6)	(74)	-	(6)	-	-	-	-	(74)	-
Foreign exchange loss	(6)	-	(5)	(1)	-	-	-	-	-	-
Gains on disposals of subsidiaries	76	15	76	-	-	-	15	-	-	-
Finance expense	(78)	(75)	(18)	(18)	(20)	(22)	(21)	(18)	(18)	(18)
Income tax (expense) recovery	(45)	4	(22)	(13)	(3)	(7)	14	(18)	22	(14)
Net income (loss)	**228**	**90**	**98**	**59**	**23**	**48**	**19**	**63**	**(58)**	**66**
Net income (loss) attributable to:										
Non-controlling interests	53	28	21	15	3	14	4	24	(26)	26
Shareholders of the Company	175	62	77	44	20	34	15	39	(32)	40
Net income (loss)	**228**	**90**	**98**	**59**	**23**	**48**	**19**	**63**	**(58)**	**66**

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 working capital. The Company includes interest and current income tax expenses 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.

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**	
	2013	**2012**	**2013**	**2012**
Net cash flows from operating activities per Consolidated Statements of Cash Flows	**497**	**242**	**157**	**29**
Add (deduct) items included in calculation of net cash flows from operating activities per Consolidated Statements of Cash Flows:				
Interest paid	67	59	18	22
Miscellaneous financing charges paid and realized loss on the settlement of interest rate derivatives included in other items of non-cash adjustments to reconcile net income to net cash flows from operating activities	4	15	-	2
Income taxes (recovered) paid	(10)	7	(15)	1
Change in non-cash operating working capital	(71)	140	(36)	46
	(10)	221	(33)	71
Finance expense excluding unrealized changes on interest rate derivatives and amortization and accretion charges	(72)	(78)	(15)	(17)
Current income tax expense (recovery)	4	(4)	-	-
Funds from operations	**419**	**381**	**109**	**83**

Cash flow per share

Cash flow per share is calculated using the weighted average common shares of Capital Power Corporation and exchangeable common limited partnership units of CPLP that were outstanding during the period. The CPLP exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis.

(unaudited)	Year ended December 31		Three months ended December 31	
	2013	**2012**	**2013**	**2012**
Funds from operations ($millions)	**419**	**381**	**109**	**83**
Weighted average common shares outstanding (millions)	72.82	66.82	79.73	69.84
Weighted average exchangeable common limited partnership units of CPLP outstanding (millions)	26.05	31.00	18.84	28.44
Weighted average shares and partnership units outstanding (millions)	98.87	97.82	98.57	98.28
Cash flow per share ($)	**4.24**	**3.89**	**1.11**	**0.84**

Discretionary cash flow

Capital Power uses discretionary cash flow as a measure of the Company's ability to pay dividends to its shareholders and distributions to CPLP's exchangeable common limited partnership unitholders from funds it generates from operations.

(unaudited, $millions)	Year ended December 31		Three months ended December 31	
	2013	**2012**	**2013**	**2012**
Funds from operations	**419**	**381**	**109**	**83**
Less sustaining capital expenditures	79	119	11	37
Adjusted funds from operations	340	262	98	46
Common share dividends declared	92	85	25	23
Distributions to exchangeable common limited partnership unitholders of CPLP declared	33	39	6	9
Preferred share dividends declared	20	6	6	2
Total dividends and distributions declared	145	130	37	34
Discretionary cash flow	**195**	**132**	**61**	**12**

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 loss on the translation of U.S. dollar denominated debt. The adjustments 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, $millions except per share amounts and number of common shares)	Year ended December 31		Three months ended							
	2013	**2012**	**Dec 2013**	**Sep 2013**	**Jun 2013**	**Mar 2013**	**Dec 2012**	**Sep 2012**	**Jun 2012**	**Mar 2012**
Basic earnings (loss) per share ($)	**2.13**	**0.84**	**0.89**	**0.55**	**0.20**	**0.44**	**0.19**	**0.55**	**(0.50)**	**0.66**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income	**175**	**62**	**77**	**44**	**20**	**34**	**15**	**39**	**(32)**	**40**
Preferred share dividends	(20)	(6)	(6)	(5)	(6)	(3)	(2)	(1)	(2)	(1)
Earnings (loss) attributable to common shareholders	155	56	71	39	14	31	13	38	(34)	39
Gain on sale of North East U.S. assets	(34)	-	(34)	-	-	-	-	-	-	-
Unrealized changes in fair value of derivatives	(13)	-	(9)	(1)	3	(6)	12	(4)	4	(12)
Restructuring charges	7	-	1	4	2	-	-	-	-	-
Reduction of amount receivable related to Sundance force majeure claim	6	-	6	-	-	-	-	-	-	-
Impairment loss on North East U.S. assets	3	37	-	3	-	-	-	-	37	-
Obligation to EPCOR for Rossdale plant	(1)	-	(1)	-	-	-	-	-	-	-
Gain on sale of hydro facilities	-	(9)	-	-	-	-	(9)	-	-	-
Genesee 1 unplanned outage costs due to plant research and development project	-	4	-	-	-	-	-	4	-	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	-	(2)	-	-	-	-	-	-	(2)	-
Income tax expense related to change in income tax rate applicable to North East U.S.	-	-	(6)	6	-	-	-	-	-	-
Normalized earnings attributable to common shareholders	**123**	**86**	**28**	**51**	**19**	**25**	**16**	**38**	**5**	**27**
Weighted average number of common shares outstanding (millions)	72.82	66.82	79.73	70.83	70.48	70.15	69.84	69.52	68.51	59.18
Normalized earnings per share ($)	**1.69**	**1.29**	**0.35**	**0.72**	**0.27**	**0.36**	**0.23**	**0.55**	**0.07**	**0.46**

Financial Highlights

(unaudited, $ millions, except per share amounts)	Year ended December 31		
	2013	2012	2011
Revenues	1,393	1,296	1,736
Adjusted EBITDA [1]	509	441	485
Net income	228	90	188
Net income attributable to shareholders of the Company	175	62	77
Normalized earnings attributable to common shareholders [1]	123	86	55
Basic earnings per share ($)	2.13	0.84	1.60
Diluted earnings per share ($) [2]	2.08	0.84	1.59
Normalized earnings per share ($) [1]	1.69	1.29	1.24
Funds from operations [1]	419	381	433
Funds from operations excluding non-controlling interests in CPILP [3]	419	381	352
Cash flow per share ($) [1]	4.24	3.89	3.89
Purchase of property, plant and equipment and other assets	943	598	493
Discretionary cash flow [1]	195	132	131
Dividends per common share, declared ($)	1.26	1.26	1.26
Dividends per Series 1 preferred share, declared ($)	1.15	1.15	1.19
Dividends per Series 3 preferred share, declared ($)	1.18	n/a	n/a
Dividends per Series 5 preferred share, declared ($)	0.90	n/a	n/a
	As at December 31		
	2013	2012	2011
Loans and borrowings including current portion	1,527	1,659	1,480
Total assets	5,219	5,134	4,743

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

[3] Diluted earnings per share was calculated after giving effect to outstanding share purchase options and the potential exchange of common limited partnership units of CPLP held by EPCOR which are exchangeable for common shares of Capital Power on a one-for-one basis.

[3] Funds from operations excluding non-controlling interests in CPILP was a non-GAAP financial measure that was applicable to years prior to 2012.

Normalized earnings and normalized earnings per share

Normalized earnings and normalized earnings per share for 2013 were higher than 2012 primarily due to stronger results from the Alberta generation plants and portfolio optimization and increased contributions from the B.C and Ontario generation plants. See Consolidated Net Income and Results of Operations for detailed discussion of the results for the year on a comparative basis.

Funds from operations

Funds from operations for 2013 increased in comparison with funds from operations for 2012 primarily due to the increase in net income on a year-over year-basis.

Significant Events

Sale of North East U.S. subsidiaries and refocusing of business

On November 19, 2013, Capital Power completed the sale of 100% of its equity interests in the entities that own the three North East U.S. combined cycle, natural gas-fired power generation facilities (the North East U.S. assets). The sale to Emera Inc. was for proceeds of $576 million (US$549 million) less transaction costs of $8 million (US$8 million). The Company recorded a pre-tax impairment loss of $6 million in the third quarter of 2013 and a pre-tax gain on disposal of $76 million primarily consisting of accumulated foreign currency translation gains related to these North East U.S. foreign subsidiaries.

The Company incurred pre-tax restructuring costs of approximately $13 million as a result of its decision to exit the North East U.S. market and to refocus its merchant power business in Alberta including the elimination of trading desk operations outside of Alberta. Future expected impacts include lower spending due to efficiencies in operations and maintenance while approximately 160 employee positions were eliminated by the end of 2013 resulting in approximately 700 active employee positions at the beginning of 2014.The expected annual cost savings are $25 million to $30 million consisting of an estimated $22 million related to general and administration (including support services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management, and environment, health and safety) and $8 million related to operations. The estimated cost savings primarily consist of employee compensation including benefits less margins from the discontinued trading operations.

Port Dover and Nanticoke facility begins commercial operations

On November 7, 2013, the Port Dover and Nanticoke wind project in Ontario began commercial operations. The 105-MW wind facility was completed on time and under its $340 million budget, with final construction costs expected to be approximately $300 million. The Port Dover and Nanticoke wind project was awarded a 20-year power purchase agreement with the Ontario Power Authority (OPA), as part of the OPA's Feed-in-Tariff program. The contracted price for power at commercial operations is $144 per MWh and thereafter, 20% of the contract price will escalate annually at inflation throughout the 20-year term.

Secondary offering of Capital Power common shares by EPCOR

On October 10, 2013, EPCOR exchanged 9,600,000 of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9,600,000 common shares of Capital Power to the public pursuant to a secondary offering at $21.00 per common share. Capital Power did not receive any of the proceeds from EPCOR's sale of common shares. These transactions reduced EPCOR's ownership interest in CPLP to approximately 19% from its interest of approximately 29% at September 30, 2013 and reduced EPCOR's ownership of the common shares of Capital Power, on a diluted basis, to 19% from 29%. 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, its requirements for capital and other circumstances that may arise in the future.

EPCOR's ownership interest in the limited partnership units of CPLP dropped below 20% as a result of these transactions. Thus, the terms of the agreement for the debt payable to EPCOR provide that EPCOR may, by advance written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon. The debt payable to EPCOR at December 31, 2013 was $341 million. Also, EPCOR may only elect two of Capital Power's directors compared to four previously.

Purchase of interest in Shepard Energy Centre and development of Genesee 4 & 5

The Company entered into a series of agreements with ENMAX Corporation (ENMAX) to purchase a 50% interest in the 800 MW natural-gas-fuelled Shepard Energy Centre (Shepard) located on the eastern limits of the City of Calgary. Shepard is expected to begin commercial operations in the first quarter of 2015. On February 28, 2013 and September 30, 2013, respectively, the purchases of the first and second tranches of the Company's interest in Shepard closed. Upon close of the first tranche, the Company paid $237 million and acquired a 25% interest in Shepard. Upon close of the second tranche, the Company paid an additional $325 million and acquired an additional 25% interest in Shepard bringing the Company's total ownership interest to 50%. The total amount incurred by the Company to the date of close of the second tranche was $649 million compared with the total anticipated capital cost of $821 million. Commencing with the close of the first tranche, all decisions related to Shepard require unanimous approval by the Company and ENMAX. As a result, the Company jointly controls Shepard with ENMAX upon close of the first tranche. Based on the terms of the Shepard agreements, the Company will account for the Shepard joint arrangement as a joint operation.

In the fourth quarter of 2013, Capital Power and ENMAX announced their letter of intent to pursue joint arrangement agreements to develop, construct, own and operate the Genesee 4 & 5 facility (formerly Capital Power Energy Centre).

$200 million offering of 4.50% Cumulative Rate Reset Preference Shares

On March 14, 2013, Capital Power Corporation issued 8 million Cumulative Rate Reset Preference Shares, Series 5

(Series 5 Shares) at $25 per share for aggregate gross proceeds of $200 million on a bought deal basis with a syndicate of underwriters.

The Series 5 Shares will pay fixed cumulative preferential dividends of $1.125 per share per annum, yielding 4.50% per annum, payable on the last business day of March, June, September and December each year, as and when declared by the Board of Directors of Capital Power Corporation. These dividends are applicable for the initial period ending June 30, 2018. The Series 5 Shares are subject to specified redemption, conversion and reset rights.

Standard & Poor's (a division of the McGraw Hill Companies, Inc.) (S&P) assigned a rating of P-3 and DBRS Limited (DBRS) assigned a rating of Pfd-3 (low) for the Series 5 Shares.

Subsequent Event

Sundance force majeure claim settlement

In July 2012, the Sundance plant owner made a force majeure claim for $39 million with respect to the 2011 third quarter outage of Unit 6 due to a transformer failure. The Company has a 52% interest in the Sundance acquired PPA for Units 5 and 6 and thus was contractually responsible for paying its share of the claimed amount in advance of final determination of whether or not a force majeure situation, as specified in the PPA, occurred. Accordingly, Capital Power paid its share of the claimed amount and, based on the Company's view that the claim would not meet the PPA specified force majeure tests, recorded it as an amount receivable until final resolution of the claim. The claim was under arbitration but the Company entered into settlement negotiations with the plant owner. At the time of payment in 2012, the Company recorded its $20 million payment as an amount receivable included in other financial assets. Based on the analysis performed in preparation for the arbitration and potential settlement with the plant owner, the Company reduced the amount receivable to $10 million in the fourth quarter of 2013. In February 2014, the Company reached a settlement with the plant owner and will receive payments consistent with the revised amount receivable. The settlement also resolves a 2012 dispute relating to Index 9 of the PPA with immaterial consequences to the Company.

Plants and Portfolio Optimization Operations

Plant category and plant	Type of generating plant	Year commissioned	Capacity (MW) Plant	Capacity (MW) 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	495	248	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)	-
Halkirk	Wind turbine	2012	150	150	Merchant with Renewable Energy Credits (RECs) sold under fixed price agreement	2032 (RECs)
Clover Bar Landfill Gas	Landfill gas-fired	2005	5	5	All output sold to 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
Kingsbridge 1	Wind turbine	2001 and 2006	40	40	Energy supply contracts with Ontario Power Authority	2027
Port Dover and Nanticoke	Wind turbine	2013	105	105	PPA with Ontario Power Authority	2033
Quality Wind	Wind turbine	2012	142	142	Electricity purchase agreement with B.C. Hydro	2036
North East U.S. commercial plants (until 2013 fourth quarter disposal)						
Bridgeport	Natural gas-fired combined cycle	1999	540	540	Merchant	-
Rumford	Natural gas-fired combined cycle	2000	270	270	Merchant	-
Tiverton	Natural gas-fired combined cycle	2000	279	279	Merchant	-
North Carolina U.S. contracted plants						
Roxboro	Solid fuels (wood residuals, tire-derived and coal)	1987	46	46	PPA with Progress Energy	2021
Southport	Solid fuels (wood residuals, tire-derived and coal)	1987	88	88	PPA with Progress Energy	2021
Under construction						
Shepard Energy Centre	Natural gas-fired combined cycle	Expected 2015	800	400	Merchant with tolling agreement for 50% of owned capacity plus additional 25% contracted for 2015 to 2017	2035 (tolling agreement)
K2	Wind turbine	Expected 2015	270	90	PPA with Ontario Power Authority	2035

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.

In August 2013, the Company announced the refocusing of its merchant power activities in the Alberta market (see Significant Events).

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, reducing 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 the year ended December 31, 2013 compared with the year ended December 31, 2012 were:

(unaudited, $ millions)	
Consolidated net income for the year ended December 31, 2012	**90**
Decrease in impairment expense	68
Increase in gains on disposals of subsidiaries	61
Changes in unrealized fair value of commodity derivatives and Atlantic Power shares	41
Increase in adjusted EBITDA for Alberta commercial plants and portfolio optimization	31
Increase in adjusted EBITDA for Ontario and British Columbia contracted plants	25
Decrease in adjusted EBITDA for Alberta contracted plants	(10)
Decrease in net unrealized gains on interest rate derivatives included in finance expense	(9)
Decrease in realized losses on settled interest rate derivatives included in finance expense	8
Decrease in adjusted EBITDA for other portfolio activities	(8)
Decrease in adjusted EBITDA for Corporate	(8)
Increase in foreign exchange expense	(6)
Decrease in adjusted EBITDA for North East U.S. commercial plants and portfolio optimization	(4)
Increase in finance expense excluding the impact of interest rate derivatives	(2)
Increase in income before tax	187
Increase in income tax expense	(49)
Increase in net income	**138**
Consolidated net income for the year ended December 31, 2013	**228**

Results by Plant Category and Other

	Year ended December 31							
	2013	2012	2013	2012	2013	2012	2013	2012
	Electricity generation (GWh)[1]		Plant availability (%)[2]		Revenues (unaudited, $ millions)		Adjusted EBITDA (unaudited, $million)[3]	
Total electricity generation, average plant availability and revenues excluding acquired Sundance PPA	16,130	16,455	93%	91%	1,110	975		
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	1,917	1,631	99%	84%	147	101		
Keephills 3	1,654	1,876	91%	99%	132	118		
Clover Bar Energy Centre 1, 2 and 3	347	471	96%	97%	85	71		
Joffre	414	341	92%	89%	66	52		
Halkirk[4]	466	44	96%	95%	47	3		
Clover Bar Landfill Gas	16	32	88%	91%	2	2		
Alberta commercial plants – owned	4,814	4,395	95%	92%	479	347		
Acquired Sundance PPA	2,772	2,610	90%	89%	208	161		
Portfolio optimization	n/a	n/a	n/a	n/a	(23)	133		
	7,586	7,005	93%	91%	664	641	350	319
Alberta contracted plants								
Genesee 1	2,950	3,166	89%	96%				
Genesee 2	3,134	3,014	94%	91%				
	6,084	6,180	91%	94%	246	282	159	169
Ontario and British Columbia contracted plants								
Island Generation	224	77	100%	100%	39	39		
Kingsbridge 1	108	109	96%	99%	7	7		
Port Dover and Nanticoke[4]	54	n/a	95%	n/a	7	n/a		
Quality Wind[4]	377	70	98%	99%	39	6		
Brown Lake[5]	n/a	47	n/a	99%	n/a	3		
Miller Creek[5]	n/a	43	n/a	65%	n/a	1		
	763	346	99%	98%	92	56	67	42
North East U.S. commercial plants[6]								
Bridgeport	2,607	2,912	88%	78%	148	124		
Rumford	124	364	91%	91%	18	26		
Tiverton	1,053	1,611	81%	91%	56	69		
Portfolio optimization	n/a	n/a	n/a	n/a	5	1		
	3,784	4,887	87%	85%	227	220	21	25
North Carolina U.S. contracted plants								
Roxboro	249	230	94%	91%	23	21		
Southport	436	417	96%	93%	48	50		
	685	647	95%	93%	71	71	5	4
Other portfolio activities					78	31	2	10
Corporate[7]					(13)	8	(121)	(113)
					1,365	1,309	483	456
Unrealized changes in fair value of commodity derivatives and Atlantic Power shares					28	(13)	26	(15)
Consolidated revenues and adjusted EBITDA					**1,393**	**1,296**	**509**	**441**

[1] 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] Halkirk, Quality Wind and Port Dover and Nanticoke include pre-commissioning output until commissioning dates of December 1, 2012, November 6, 2012 and November 7, 2013, respectively. Revenues and expenses related to commissioning activities were capitalized as part of the cost of the facility in property, plant and equipment.

[5] Brown Lake and Miller Creek were disposed of on October 12, 2012.

[6] The North East U.S. plants were disposed of on November 19, 2013.

[7] Corporate revenues are offset by interplant category revenue eliminations.

Energy prices and hedged positions

		Year ended December 31	
	Unit	**2013**	**2012**
Alberta			
Hedged position [1]	Percentage sold forward at beginning of year (%)	49	48
Spot power price average	$/MWh	80	64
Realized power price [2]	$/MWh	78	72
Natural gas price (AECO) [3]	$/gigajoule (Gj)	3.01	2.27
North East U.S.			
Hedged position	Approximate average percentage hedged at the beginning of year (%)	72	46
New England mass hub	US$/MWh	53	36

[1] Hedged position is for the Alberta baseload plants and acquired Sundance PPA.

[2] Realized power price is the average price realized on the Company's Alberta commercial contracted sales and portfolio optimization activities.

[3] AECO means a 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

Production increased 581 GWh for full year 2013 compared with 2012 primarily due to the addition of Halkirk which commenced operations in December 2012. Overall availability for 2013 was higher compared with 2012. This was primarily due to increased availability from Genesee 3 partly offset by the reduced availability of Keephills Unit 3. Genesee 3 was offline from January 1 to 15, 2012 due to an electrical design issue that resulted in damage to the turbine/generator bearings and rotor. Genesee 3 was also offline from October 1, 2012 to November 8, 2012 due to an extended planned outage. There were no comparable outages for Genesee 3 in 2013. Reduced Keephills availability reflects a planned outage from May 24 to June 22, 2013 with no comparable outage in 2012.

The average Alberta spot power price of $80/MWh for 2013 was significantly higher than 2012 which had an average spot price of $64/MWh. In 2013, higher Alberta spot prices reflected higher price volatility compared with the prior year due to a tighter supply demand balance driven by several planned and unplanned plant outages in the Alberta market and lower than historical wind capacity.

Higher revenues and adjusted EBITDA for 2013 compared with 2012 primarily reflected the impact of higher Alberta power prices on portfolio generation, the impact of the Genesee 3 outages in 2012, increased opportunities to dispatch Joffre, and a full year of operations for Halkirk.

Higher adjusted EBITDA for 2013 also reflected a concerted effort to reduce contractor and material costs at Genesee 3 resulting in savings of approximately $4 million partly offset by trading results related to the Company's portfolio optimization strategies, a 2013 reduction of the amount receivable related to the Sundance Unit 6 force majeure claim (see Contractual Obligations and Contingent Liabilities), higher 2013 Sundance acquired PPA greenhouse gas emission costs, and higher 2013 costs related to an outage on CBEC Unit 2. Portfolio optimization strategies employed by the Company positioned the portfolio with enough length to take advantage of anticipated market conditions in both years. However, in 2013, Alberta pool prices were significantly higher than 2012 resulting in hedged positions settling at prices lower than spot prices for more hours in 2013 compared with 2012. In 2012, the Company identified an adjustment in the calculation of greenhouse gas emission compliance costs due to the Alberta government. This resulted in a credit of $5 million related to prior periods recorded in 2012 with no comparable credit in 2013. CBEC Unit 3 was offline from September 21 to October 19, 2013 for a rotor repair and bearing replacement. The outage resulted in additional costs of $5 million with no comparable outages in 2012. As the 2013 outage took place during periods with low power prices there was no significant impact to the dispatch strategy of the plant.

Alberta contracted plants

Production and availability decreased slightly in 2013 compared with 2012 primarily due to a longer major planned outage and several maintenance outages in 2013. Genesee 1 was offline in 2013 for a planned outage of 27 days while Genesee 2 underwent a planned outage of 24 days in 2012. In addition, Genesee 1 and 2 were offline for a total of 25 days in 2013 for unplanned maintenance outages while Genesee 1 experienced an unplanned outage in the third quarter of 2012 resulting from a trial project intended to increase the marketability of fly ash by-product.

Both revenues and adjusted EBITDA for 2013 decreased compared with the previous year. These results reflected the impact of higher availability penalties under the plants' PPA resulting from the increased outages in 2013 and higher rolling average power prices compared with 2012. Capacity revenues also decreased in 2013 due to required reductions in some of the indices embedded in the plants' PPA used to determine capacity payments. Lower revenues were partly offset by reduced costs in 2013 which primarily reflected savings of approximately $4 million resulting from a concerted effort to reduce contractor and material costs. Expenses deducted in determining adjusted EBITDA were also lower on a year-over-year basis by approximately $10 million due to a change in coal cost methodology whereby coal mine stripping costs were reported as depreciation and amortization commencing in 2013.

Ontario and British Columbia contracted plants

Production in 2013 increased compared with 2012 primarily due to the additions of Quality Wind (commenced operations on November 6, 2012) and the Port Dover and Nanticoke wind project (commenced commercial operations on November 7, 2013) and significantly higher generation from Island Generation partly offset by decreased production due to the disposal of the Brown Lake and Miller Creek hydro facilities in the third quarter of 2012. Overall availability for 2013 was consistent with the prior year.

Increased revenues and adjusted EBITDA primarily reflected a full year of operations of Quality Wind in 2013 compared with two months in 2012 and the increased generation from the addition of Port Dover and Nanticoke in late 2013.

The increased generation from Island Generation in 2013 compared with 2012 had little impact on revenues and adjusted EBITDA 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 2013 was consistent with 2012.

North East U.S. commercial plants and portfolio optimization

The North East U.S. commercial plants were sold effective November 19, 2013. Generation volumes on a year-over-year basis reflected the decrease in months of operation under Capital Power's control, variability associated with planned outages, and lower dispatch of the Rumford facility in 2013. Despite the decrease in production, revenues and adjusted EBITDA for 2013 were relatively consistent with 2012 as availability increased and cost reductions were realized as a result of the Company's operations improvement program.

Apart from the plant operations, portfolio optimization activities produced improved results in 2013 as the 2012 net realized losses on the Bridgeport heat rate option and other trading losses did not reoccur.

North Carolina U.S. contracted plants

The 2013 performance of the North Carolina U.S. contracted plants was relatively consistent with 2012. Generation increased marginally as the result of shorter planned outages at both plants compared with the 2012 outages.

2013 revenues remained consistent with 2012 as the impact of higher generation was almost completely offset by the impact of lower renewable energy credits (REC) pricing compared with 2012. The REC pricing will also be lower throughout 2014 with increased pricing in 2015. Adjusted EBITDA increased slightly, primarily due to savings on maintenance costs in 2013, reflecting shorter planned outages compared to 2012.

Other portfolio activities

Other portfolio activities reflect revenues and adjusted EBITDA for natural gas and emissions trading activities. Revenues were higher for 2013 compared with 2012 due to higher trading volumes. However, adjusted EBITDA for 2013 compared with 2012 reflected higher losses on such transactions partly offset by reduced provisions for estimated future losses on certain natural gas contracts. During 2012, a reduction in the provision was also recorded but was greater than that recorded in 2013. The natural gas trading operations, aside from procurement for Capital Power's natural gas-fired power plants, were wound down in 2013 as part of refocused strategy (see Significant Events).

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 Company incurred restructuring charges of approximately $13 million as a result of its decision to exit the North East U.S. market and other portfolio activities and to refocus on merchant power business in Alberta. Reclassification of certain expenses from plant operations also resulted in decreased adjusted EBITDA for the Corporate category. The restructuring charges and expense reclassification were partly offset by lower compensation costs following the restructuring and reduced long-term disability and performance incentive expenses.

Unrealized changes in fair value of commodity derivatives and Atlantic Power shares

($ millions)	Year ended December 31			
Unrealized changes in fair value of commodity derivatives and Atlantic Power shares	**2013**	**2012**	**2013**	**2012**
	Revenues		**Adjusted EBITDA [1]**	
Unrealized gains on Alberta energy derivatives	6	12	4	8
Unrealized gains (losses)on Bridgeport heat rate option	18	(15)	18	(15)
Unrealized gains (losses) on natural gas derivatives	6	(6)	4	(4)
(Reversal) of unrealized gain on Atlantic Power shares	-	(5)	-	(5)
Other	(2)	1	-	1
	28	**(13)**	**26**	**(15)**

1 The financial results, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

The Company's financial results relating to its Alberta commercial plants and portfolio optimization, North East U.S. commercial plants and portfolio optimization, and other activities include unrealized changes in the fair value of commodity derivatives and, until its disposal in February 2012, the Company's investment in Atlantic Power.

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 portfolio optimization or Corporate category.

Alberta desk electricity portfolio activities in 2013 accounted for unrealized net gains of $4 million compared with unrealized net gains of $8 million for 2012. These unrealized gains primarily reflected the impact of decreases in Alberta forward power prices on the portfolio positions and the reversal of previously recognized unrealized net losses on contracts which settled in 2013 and 2012.

Upon acquisition of the North East U.S. plants in the second quarter of 2011, the Company acquired heat rate options related to the Bridgeport facility. The 2013 unrealized gains on the Bridgeport heart rate option of $18 million primarily reflected the reversal of the 2012 unrealized losses. In 2012, the Company recognized unrealized losses of $15 million primarily resulting from increases in the underlying forward power prices and the reversal of the 2011 unrealized gains.

Natural gas portfolio activities in 2013 accounted for unrealized net gains of $4 million which primarily reflected the reversal of unrealized net losses which were recognized in 2012 and reversed in 2013 as the related contracts settled. These natural gas portfolio activities primarily related to the North East U.S. and other natural gas trading outside of the North East U.S. and Alberta. These activities wound down in 2013 as the North East U.S. assets were sold and other trading desk operations were shut down. As the related contracts settled throughout 2013 up until the date of sale, the realized gains or losses were recognized in the applicable plant category.

In the first quarter of 2012, the Company sold its investment in Atlantic Power shares resulting in an unrealized loss of $5 million representing the reversal of the unrealized gain which was recorded in the fourth quarter of 2011. This was offset by the realized gain of $4 million which was included in the Corporate category.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $ millions)	Year ended December 31	
	2013	**2012**
Interest on borrowings less capitalized interest	(68)	(64)
Realized gains (losses) on the settlement of interest rate derivatives	1	(7)
Other finance expense – sundry interest and guarantee and other fees	(5)	(7)
	(72)	(78)
Unrealized (losses) gains representing changes in the fair value of interest rate derivatives	(1)	8
Other finance expense – amortization and accretion charges	(5)	(5)
Total finance expense	(78)	(75)
Depreciation and amortization	(222)	(221)
Impairments	(6)	(74)
Foreign exchange losses	(6)	-
Gains on disposal of subsidiaries	76	15
Income tax (expense) recovery	(45)	4
Net income attributable to non-controlling interests	53	28

Finance expense

Finance expense for 2013 included $1 million of unrealized gains on an interest rate swap. This gain was offset by the unrealized foreign exchange loss on a foreign exchange derivative contract. Higher finance expense for 2013 compared with 2012 was primarily due to increased borrowings related to capital projects and the varying levels of capitalized interest related to the timing of completion of certain projects and the timing of commencement of other projects.

Depreciation and amortization

Depreciation and amortization for 2013 increased $1 million compared with 2012 primarily due to the addition of depreciation on the Halkirk facility which commenced operations in the fourth quarter of 2012. Depreciation and amortization for 2013 also increased compared with 2012 depreciation and amortization due to the reclassification of coal mine stripping costs from energy purchases and fuel. These increases were partly offset by depreciation and amortization decreases for 2013 compared with 2012 because of the sale of the North East U.S. assets.

Impairments

An asset impairment charge of $6 million related to the North East U.S. assets was recognized in the third quarter of 2013 immediately before classifying those assets as held for sale and in advance of the final disposal of the U.S. subsidiaries. The impairment recognized in 2012 related to the North East U.S. commercial plants and resulted from reduced expected operating margins. The reductions in the expected operating margins were largely the results of weaker spark spreads in the New England power market.

Foreign exchange losses

Foreign exchange losses for 2013 were $6 million reflecting the impact of changes in foreign exchange rates on U.S. dollar denominated debt. The foreign exchange losses on this debt were recognized in net income rather than other comprehensive income subsequent to the sale of the North East U.S. assets. Foreign exchange losses for 2012 were $nil since no material foreign exchange contracts settled in the year.

Gains on disposals of subsidiaries

In 2013, the Company recognized a pre-tax gain of $76 million on the sale of its North East U.S. assets primarily consisting of foreign exchange gains which were recognized in other comprehensive income and deferred in accumulated other comprehensive income from the date of acquisition of these U.S. subsidiaries in 2011 until their disposal in the third quarter of 2013. In 2012, the Company recognized a pre-tax gain of $15 million on disposal of its limited partnership that owned the two hydro facilities, Brown Lake and Miller Creek.

Income tax expense

Income tax expense increased $49 million for 2013 compared with the prior year primarily due to higher consolidated net income in 2013 compared with 2012 and the tax impacts of the 2013 sale of the North East U.S. assets and the 2012 impairment of the North East U.S. assets.

Non-controlling interests

For 2013, approximately 27% of CPLP's net income was attributable to EPCOR which is reported as net income attributable to non-controlling interests by the Company. EPCOR's October 10, 2013 exchange of exchangeable common limited partnership units for common shares of Capital Power reduced its interest in CPLP from 29% to 19%. These changes in ownership interest reduce the proportion of net income attributable to non-controlling interests reported by the Company in future periods. Net income attributable to non-controlling interests also included the Genesee coal mine partner's share of the consolidated depreciation of the coal mine assets.

Comprehensive Income

($ millions)	Year ended December 31	
Comprehensive income	**2013**	**2012**
Net income	228	90
Other comprehensive (loss) income :		
Net unrealized (losses) gains on commodity derivatives designated as cash flow hedges	(35)	54
Net realized losses (gains)and ineffective portion of unrealized (gains) losses on commodity derivatives designated as cash flow hedges reclassified to revenues and/or energy purchases and fuel	27	(12)
Unrealized foreign exchange gains (losses) on the translation of foreign operations	23	(10)
Foreign exchange gains realized in net income on disposal of foreign subsidiaries	(59)	-
Actuarial gains (losses) related to the Company's defined benefit pension plans	2	(6)
	(42)	26
	186	**116**

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 will not be subsequently recognized in net income.

Financial Position

(unaudited, $ millions)	As at December 31			Increase (decrease) due to		
	2013	2012	Increase (decrease)	Carrying amount of North East U.S assets disposed of	Other	Primary other changes
Trade and other receivables	208	354	(146)	(4)	(142)	Lower trade receivables related to Alberta operations resulting from lower power prices and the reclassification of the Shepard deposit to property, plant and equipment.
Inventories	92	82	10	(9)	19	Purchase of emission credits.
Net derivative financial instruments assets	26	13	13	-	13	Increases in the fair value of commodity derivative contracts influenced by decreased Alberta forward power prices.
Finance lease receivables	711	461	250	-	250	Addition of Port Dover and Nanticoke partly offset by payments received in respect of the Quality Wind and Kingsbridge 1 facilities.
Equity-accounted investment	15	3	12	-	12	Contributions to K2 joint venture during year.
Intangible assets	310	306	4	(15)	19	Software additions partly offset by amortization.
Property, plant and equipment	3,525	3,628	(103)	(592)	489	Capital additions (most significantly, Shepard Energy Centre) partly offset by depreciation and amortization.
Trade and other payables	198	210	(12)	(12)	-	Trade and other payables year-end balances have remained consistent.
Loans and borrowings (including current portion)	1,527	1,659	(132)	-	(132)	Repayment of credit facilities that were drawn and outstanding at the end of 2012.
Net deferred tax liabilities	85	42	43	(20)	63	Increased deferred tax liabilities on finance lease receivables and decommissioning provisions and the impact of increased ownership of CPLP.
Provisions (including current portion)	175	238	(63)	(37)	(26)	Decreased decommissioning provisions resulting from discount rate changes partly offset by the addition of decommissioning provisions for Shepard and Port Dover and Nanticoke.
Share capital	2,328	1,903	425	-	425	Issuance of common (primarily common shares issued upon EPCOR conversion of CPLP limited partnership units) and preferred shares.
Non-controlling interests	587	829	(239)	-	(239)	Conversion of CPLP common limited partnership units to Capital Power common shares by EPCOR in October 2013 and distributions offset by earnings attributable to non-controlling interests.

Liquidity and Capital Resources

(unaudited, $ millions)	Year ended December 31		
Cash inflows (outflows)	**2013**	**2012**	**Increase (decrease)**
Operating activities	497	242	259
Investing activities	(348)	(466)	114
Financing activities	(101)	205	(306)

Operating activities

Cash flows from operating activities for 2013 increased compared with 2012 primarily due to reductions in trade and other receivables and the increase in net income.

Investing activities

The 2013 cash flows from investing activities included net proceeds on disposal of the North East U.S. assets of $569 million (excludes working capital adjustment of $1 million) compared with the 2012 net proceeds on disposal of the hydro facilities of $58 million and proceeds on the disposal of Atlantic Power shares of $52 million.

The cash flows used in investing activities for 2013 included $943 million for capital expenditures and investments, most significantly, the Shepard Energy Centre and Port Dover and Nanticoke projects.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2012 Actual	Year ended December 31 2012 Actual	2013 Actual	2014 Estimated [1, 2]	Actual or Projected Total [2, 3]	Timing
Quality Wind	155	264	(6)	n/a	413	Commercial operation 4th quarter 2012
Halkirk	183	131	9	n/a	323	Commercial operation 4th quarter 2012
Port Dover and Nanticoke	49	19	208	24	300	Commercial operation 4th quarter 2013
K2 [4]	-	3	13	31	291	Projected completion 2015
Shepard Energy Centre	-	50	634	137	821	Projected completion 2015
Subtotal growth projects		**467**	**858**			
Sustaining – plant maintenance excluding Genesee mine		102	58			
Sustaining – Genesee mine maintenance and lands [5]		17	16			
Sustaining – other		-	5			
Total capital expenditures [6]		**586**	**937**			
Emission credits		35	27			
Capitalized interest		(23)	(21)			
Purchase of property, plant and equipment and other assets		**598**	**943**			

[1] The Company's 2014 estimated capital expenditures include only expenditures for previously identified growth projects and exclude the cost of Genesee 4 & 5 and other potential new development projects.

[2] Costs for projects completed in 2012 and 2013 include certain costs that were or are expected to be incurred subsequent to the date of commercial operations such as site remediation, vendor optimization, project clean-up, and project close-out costs.

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

[4] Capital Power entered into a partnership agreement to develop K2 which is expected to be in operation by 2015. The 2014 estimated expenditures for K2 primarily consist of the Company's estimated equity contribution to the partnership.

[5] Capital expenditures for Genesee mine maintenance represent only those capital expenditures funded by the Company for the Genesee mine operation.

[6] Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the Statement of Cash Flows as purchase of property, plant and equipment and other assets.

Financing activities

The cash flows from financing activities during 2013 primarily reflected debt repayments of $155 million and distributions to non-controlling interests, common share dividends and preferred share dividends paid of $117 million partly offset by the $200 million proceeds from the March 2013 issuance of preferred shares.

The Company's credit facilities consisted of:

($millions)		As at December 31, 2013			As at December 31, 2012		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
CPLP committed credit facility	2018	1,200			1,200		
Letters of credit outstanding			160			208	
Bankers' acceptances outstanding			-			103	
U.S. dollar bank loans outstanding			-			30	
		1,200	160	1,040	1,200	341	859
CPLP demand facility	n/a	20	-	20	20	-	20
Capital Power Corporation demand facility	n/a	5	-	5	5	-	5
		1,225	**160**	**1,065**	**1,225**	**341**	**884**

As at December 31, 2013, the committed credit facility utilization decreased $181 million compared to the utilization as at December 31, 2012 primarily due to improved cash flows from operations, proceeds from issuance of preferred shares and proceeds from asset sales partly offset by capital investments. In the fourth quarter of 2013, Capital Power used the proceeds from the sale of the North East U.S. facilities to repay the credit facility utilization which financed the second tranche payment for its 50% interest in Shepard. In July 2012, the committed credit facility was amended to include an accordion feature to increase the facility size by $300 million in the future, subject to certain conditions including lender approval. Effective June 28, 2013, the maturity date of CPLP's credit agreements was extended to July 9, 2018.

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

On November 16, 2012, S&P revised CPLP's corporate credit rating from BBB to BBB- with a stable outlook. The BBB- rating assigned by S&P is an investment grade credit rating. 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.

CPLP has a long-term debt credit rating of BBB from 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 CPLP'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, 2013
Senior debt to consolidated capitalization ratio [1]	Not more than 0.65 to 1.0	0.37 to 1.0
Consolidated EBITDA to consolidated interest expense [1, 2]	Not less than 2.5 to 1.0	3.8 to 1.0

[1] As defined in the relevant agreements.

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

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 estimated cash requirements for 2014 are expected to include approximately $227 million for capital expenditures, approximately $24 million for CPLP distributions to EPCOR (subject to approval by the Board of Directors of CPLP's general partner), approximately $102 million for Capital Power's common share dividends, and approximately $22 million for quarterly preferred share dividends (subject to approval by Capital Power Corporation's Board of Directors). Effective January 1, 2012, Capital Power Corporation launched a Dividend Re-investment Plan where shareholders may elect to reinvest their quarterly cash dividends for additional shares of Capital Power Corporation as an alternative to receiving cash dividends. The participation rate in the Dividend Re-investment Plan was approximately 31% for 2013 dividends. Depending on the participation rate for 2014, cash requirements for common share dividends may differ from the above expectations.

The current portion of loans and borrowings on the December 31, 2013 statement of financial position of $346 million primarily consists of $341 million senior debt payable to EPCOR which was classified as current since the debt is callable and therefore, potentially repayable in 2014 (see Transactions with Related Parties).

The Company expects to fund the construction of the Shepard Energy Centre and K2 projects using existing bank credit facilities, cash flows from operating activities, and a portion of the proceeds from the sale of the North East U.S. assets. K2 will be financed by non-recourse project debt issued by the K2 limited partnership. 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's two short form base shelf prospectuses provide, market conditions permitting, the Company with the ability to obtain new debt and equity capital from external markets when required. Under the short form base shelf prospectuses, Capital Power may raise up to $2 billion by issuing common shares, preferred shares, or subscription receipts exchangeable for common shares or other securities of the Company, and up to $1 billion by issuing medium-term notes with maturities of not less than one year. As of the date of this MD&A, Capital Power has approximately $1.2 billion of equity and $1 billion of debt available under these short form base shelf prospectuses. The equity prospectus expires March 2014 and the debt prospectus expires July 2014; both prospectuses are expected to be renewed in the second quarter of 2014.

Financial market stability remains an issue. If instability reoccurs in the Canadian and U.S. financial markets, CPLP'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. CPLP has credit exposure relating to various agreements, particularly with respect to its PPA, trading and supplier counterparties. While CPLP 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, 2013, $160 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

($ millions)	As at December 31	
	2013	**2012**
Loans and borrowings	1,527	1,659
Less cash and cash equivalents	100	53
Net debt	1,427	1,606
Share capital	2,328	1,903
Retained earnings and other reserves	89	20
Non-controlling interests	587	829
Total equity	3,004	2,752
Total capital	**4,431**	**4,358**

Shareholder Rights Plan

On April 26, 2013, at Capital Power's annual general meeting of shareholders, the Shareholder Rights Plan (Rights Plan) was ratified. 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.

Contractual Obligations and Contingent Liabilities

(unaudited, $ millions)	Payments due by period						
	2014	2015	2016	2017	2018	Thereafter	Total
Loans and borrowings	346	306	5	5	5	872	1,539
Interest on loans and borrowings	83	61	47	46	45	99	381
Capital – growth projects [1]	191	244	-	-	-	-	435
Acquired PPA obligations – fixed [2]	59	60	59	61	61	129	429
Acquired PPA obligations – variable [2]	34	41	44	45	48	106	318
Decommissioning provisions [3]	1	2	1	2	2	283	291
Energy purchase and transportation contracts [4]	79	33	23	3	3	71	212
Operating and maintenance contracts	13	13	12	11	12	57	118
Operating leases	8	8	7	7	8	78	116
Environmental credits	26	17	8	7	2	-	60
Commodity and other derivatives liabilities net of financial assets	28	2	3	1	-	-	34
Total	**868**	**787**	**209**	**188**	**186**	**1,695**	**3,933**

[1] Capital Power's obligations for capital – growth projects include the K2 and Shepard Energy Centre projects. Genesee 4 & 5 is not included.

[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 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] Includes natural gas transportation contracts which are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2014 to 2019.

Contingent liabilities

Capital Power is participating in a proceeding underway before the Alberta Utilities Commission (AUC) regarding factors that form the basis for certain transmission charges paid by Alberta generators including Capital Power. On April 16, 2012, the AUC issued its decision that the factors used from 2006 forward were non-compliant with the applicable legislation and regulations. Capital Power and other Alberta generators subsequently submitted applications to review and vary that decision. On April 23, 2013, the AUC issued its subsequent decision that there is substantial doubt regarding the correctness of the previous decision. The AUC has scheduled a review proceeding that will determine whether the initial decision should be varied and, if so, how. This includes the potential application of alternative factors on a prospective or retrospective basis. Capital Power may incur additional payments for transmission charges on a retrospective and go-forward basis but a provision has not been recorded in the Company's financial statements since the outcome of the proceeding is not known. The AUC review proceeding commenced in October 2013 and it is anticipated that the AUC's decision will be issued no sooner than the first half of 2014.

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

(unaudited, $ millions)		Year ended December 31	
	Note	2013	2012
EPCOR (shareholder)			
CPLP distributions paid	(a)	36	42
Purchase of distribution and transmission services	(b)	1	7
Purchase of other services	(b)	6	6
Power sales	(b)	6	9
Interest incurred on unsecured senior debt payable and expensed	(c)	18	20
Interest incurred on unsecured senior debt payable and capitalized	(c)	4	5
Repayment of unsecured senior debt payable	(c)	14	25
The City of Edmonton (sole shareholder of EPCOR)			
Power sales	(b)	21	21

		As at December 31	
	Note	2013	2012
EPCOR (shareholder)			
Trade and other receivables	(b)	1	1
Trade and other payables	(b)	14	17
Provision for future maintenance costs associated with EPCOR's Rossdale plant	(d)	3	4
Loans and borrowings	(c)	341	357
The City of Edmonton (sole shareholder of EPCOR)			
Trade and other receivables	(b)	5	7

(a) In October 2013, EPCOR exchanged 9.600 million of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis. Subsequently, EPCOR entered into an agreement for a secondary offering of 9.600 million common shares of Capital Power. Thus, as at December 31, 2013, EPCOR owned 18.841 million exchangeable common limited partnership units of CPLP (representing approximately 19% of CPLP) and 18.841 million special voting shares and the one special limited voting share of Capital Power Corporation. As at December 31, 2012, EPCOR owned 28.441 million exchangeable common limited partnership units of CPLP (representing approximately 29% of CPLP) and 28.441 million special voting shares and the one special limited voting share of Capital Power Corporation. In connection with EPCOR's unitholdings, CPLP paid distributions to EPCOR for the years ended December 31, 2013 and 2012.

(b) The power sales and purchase of other services transactions with EPCOR and the City of Edmonton were in the normal course of operations and were recorded at exchange amounts which were based on normal commercial rates. The Company has a lease agreement with EPCOR for office space that requires payment to EPCOR of $5 million per year through 2031.

(c) The Company's unsecured senior debt payable to EPCOR, at interest rates ranging from 5.80% to 9.00% per annum, matures between 2014 and 2018. As at December 31, 2013, 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.

(d) The Rossdale plant, which is owned by EPCOR, was taken out of service in January 2009 and was decommissioned. Certain structures at the plant site were designated as Provincial Historical Resources by the Province of Alberta and are thereby legally protected from demolition. These structures, and additional structures at the plant site, are also on the City of Edmonton's Register of Historic Resources. CPLP has an obligation to EPCOR to share in some of the costs for ongoing operations and maintenance of the Rossdale plant and related assets until 2019.

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 for the Company are established by the Board of Directors annually and govern the Company's decisions and policies associated with risk. The Board of Directors reviews the Company's risk profile on a semi-annual basis and material changes to the risk profile on a quarterly basis.

Capital Power has implemented 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, 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 review and recommendation. They meet periodically to review enterprise risk management performance and to evaluate significant or emerging risks. The Director, 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 risk management (middle office) function. 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:

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 wholesale markets of Alberta, Ontario, and the U.S. Such transactions are settled at the spot market prices of the respective markets. 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 spot electricity 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. For the Company's Genesee 3, Keephills 3, CBEC and Joffre plants, and the acquired Sundance PPA plant, electricity spot 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 which may result in lost opportunity costs. 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 commercial contracts such as those contracts for the Company's Genesee 1 and 2, Kingsbridge 1, Port Dover and Nanticoke, Quality Wind, Island Generation, Roxboro and Southport plants.
- 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.
- 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.

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, and operations. Capital Power is required to maintain numerous licenses, permits and governmental approvals for the 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, such as the Dodd-Frank Wall Street Reform and Consumer Protection Act, 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.

Many of 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, 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.

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 with respect to policy development and current and potential 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.

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.

Strategies employed for managing operations risk:

- Execute appropriate operating and maintenance practices 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.
- Participate in a leased engine program for the LMS 100 units at CBEC to reduce down time by replacing a failed unit with a leased unit provided by the manufacturer.
- Establish and maintain appropriate business interruption and property and boiler insurance to reduce the impact of prolonged outages caused by insured events.

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 Sundance PPA and plants operated by third parties risk:

- Work with plant owner and/or operator to execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time.
- Proactively assess and appropriately respond to, including legal actions, any claims of force majeure incidents.

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 information technology system risk:

- 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 unauthorized systems or devices.

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, proactive relationships with credit rating agencies.
- Develop flexible 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 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.
- 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 electricity 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.

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 facing a tight Alberta labour market and 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.

The Company's collective agreement with UNIFOR Local 829 which represents power engineers at the Genesee power plant expired December 14, 2013.

Strategies employed for managing human resources risk:

- Establish and maintain good human resource programs and practices including monitoring developments and contingency plans.

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:

- Establish and strengthen a company-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 the appropriate communication and follow-up.

Competition, acquisition and development 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 support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

In developing 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 and development 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.

External factors risk

Capital Power requires energy from sources such as coal, natural gas, wind, wood waste and tire derived fuel 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 generation capacity. Fluctuations in wind speed or duration could have a material negative impact on revenues for these facilities in any year.

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.

Strategies employed for managing energy supply risk:

- Establish long-term supply agreements.
- Maintain coal stock-pile inventories.
- Establish contracts with fuel cost-flow provisions, where possible.

Capital Power's operations are exposed to potential damage resulting from extreme storm and other weather conditions and natural disasters.

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.
- Put appropriate insurance coverage in place.

For as long as EPCOR maintains a significant indirect equity and voting interest in the Company, EPCOR will have the ability to significantly influence the outcome of shareholder votes, including the ability to prevent certain fundamental transactions. As a result, EPCOR has the ability to influence many matters affecting the Company.

Conflicts of interest and disputes may arise between Capital Power and EPCOR relating to a potential misalignment between the companies' corporate objectives and business interests or the companies' past and ongoing relationships. Capital Power may not be able to resolve a potential conflict, and if it does, the resolution may be less favourable to Capital Power than if it were dealing with a party that was not a significant holder of equity of the Company.

Furthermore, EPCOR's significant equity ownership may discourage transactions involving a change of control of the Company, including transactions in which a holder of common shares might otherwise receive a premium for its common shares over the then-current market price.

The interests of other common shareholders are protected by the Board structure which provides EPCOR the right, voting separately as a class, to nominate and elect two directors of the Company. There are currently eleven directors on Capital Power's Board of Directors.

EPCOR has no contractual obligation to retain any exchangeable common limited partnership units of CPLP or common shares of the Company. At December 31, 2013, EPCOR's interest in the Company was approximately 19%. EPCOR has advised the Company that it plans to eventually sell all or a substantial portion of the common shares underlying its exchangeable common limited partnership units, subject to market conditions, its requirement for capital and other circumstances that may arise in the future. Capital Power is entitled to defer such offerings of common shares requested by EPCOR in certain circumstances for a limited period. Any sale of substantial amounts of common shares in the public market by EPCOR or the Company, or the perception that such sales could occur, could adversely affect prevailing market prices for the common shares and impede the Company's ability to raise capital through the issuance of additional equity securities.

Strategies employed for managing EPCOR ownership risk:

- Maintain good relationship with EPCOR to ensure that EPCOR continues to act only as an investor in and not as a manager of the Company.

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 taxes, foreign exchange, weather, legal and arbitration proceedings, and risks that are not fully covered by various insurance policies.

Environmental risk is disclosed in several different types of risks discussed in other areas of this Risk and Risk Management section including people risk, legal, regulatory and stakeholder risk, equipment and systems risk, physical (such as weather) risk, litigation risk and reputation risk.

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

The sensitivity of changes in income tax rates based on the Company's 2013 income before tax is estimated as follows:

($ millions)	Income tax rate	
	Increase of 1%	Decrease of 1%
Estimated increase (decrease) in net income	(3)	3

The statutory income tax rate on income before tax for 2013 was 25% (2012 – 25%). 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 risk:

- Develop and maintain tax expertise and resources necessary to interpret tax legislation.
- Comply with tax laws of jurisdictions that Capital Power operates in.
- Consult with government with respect to policy development and proposed legislation.

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 reliance on 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, 2013, the Company loaned $460 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.

Some of Capital Power's assets are operated through joint ventures or partnerships 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 partnership risk, there can be no assurance that such operations will continue to be effective.

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, 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 $120 million as at December 31, 2013 ($173 million as at December 31, 2012) 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 Company is obligated to purchase environmental credits totaling approximately $60 million in future years and expects to use these credits to comply with applicable environmental regulations.

Critical Accounting Estimates and Accounting Judgments

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the Company's critical accounting estimates which make assumptions about matters that are highly uncertain at the time the accounting estimate is made or for which period-to-period changes in the estimate would have a material impact on financial condition, changes in financial condition or financial performance.

Key sources of estimation uncertainty

Financial instruments

The valuation of the Company's derivative instruments and certain other financial instruments requires estimation of fair value of each instrument at the reporting date.

Non-financial assets

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.

For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. 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. Goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the cash generating units (CGU) that are expected to benefit from the acquisition.

Estimates of fair value for the recoverable amount of CGUs undergoing impairment testing and for purchase price allocations for business combinations require significant judgment and are primarily based on discounted cash flow projection techniques employing estimated future cash flows based on assumptions regarding the expected market outlook and cash flows from each CGU or asset. The cash flow estimates will vary with the circumstances of the particular assets or CGU and will be primarily based on the lives of the assets, contract prices, estimated future prices, revenues and expenses, including growth rates and inflation, and required capital expenditures. Market capitalization and comparative market multiples, where available, are used to corroborate management's discounted cash flow projections.

For purposes of impairment testing of non-financial assets, assets that are managed as a portfolio 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 purpose 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.

The Company has determined its CGUs and, for non-financial assets subject to depreciation and amortization, it performs impairment testing 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 circumstances indicate that the carrying amount may be impaired.

Identifying events or changes in circumstances that may indicate or cause a non-financial asset's carrying amount to exceed its recoverable amount requires significant judgment in assessing what events or circumstances would have such an impact. For 2013, the Company recognized an impairment loss of $6 million (2012 - $74 million) relating to the North East U.S. assets.

Impairment charges or reversals of impairment charges are expected to occur more frequently than reported in the past due to changes in Canadian GAAP when IFRS was adopted effective 2011. Assets that are acquired or developed are initially recorded at their fair value which is subject to change as company, industry and general economic conditions fluctuate. The Company performs goodwill impairment testing on an annual basis and current assessments of fair value of its assets on a regular basis which may result in the recognition of impairment losses or reversals of losses.

Decommissioning and other provisions

Measurement of the Company's provisions and the related selection of discount rates requires the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required, and related future cash flows for the decommissioning provisions and estimates of expected customer renewals for the Company's other provisions. Significant judgment is required in making these estimates.

The Company estimates the undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $291 million, calculated using an inflation rate of 2%. The expected timing for settlement of the obligations is between 2014 and 2061, which reflects the anticipated useful lives of the different power plants. The majority of the payments to settle the obligations are expected to occur between 2033 and 2061 for the power generation plants and between 2014 and 2020 for the non-reclaimed sections of the Genesee coal mine. Discount rates used to calculate the carrying amount of the obligation ranged from 1.13% to 4.07%. 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.

The Company owns retail and commercial natural gas customer contracts in Alberta, acquired as part of the July 1, 2009 acquisition of assets from EPCOR. The future unavoidable costs of meeting the terms of these contracts are expected to exceed the economic benefits to be received under these contracts. As a result, a provision was recorded to reflect the estimated present value of the loss on these contracts. The expected timing of settlement of these contracts range from 2014 to 2046 and the costs were discounted using risk free rates between 1.06% and 3.23%. The timing and settlement of the obligation is dependent on expectations or renewal of the contracts and expectations of the forward price of natural gas.

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 tax assets are assessed and significant judgment is applied to determine the likelihood that they will be realized from future taxable income.

Revenue recognition

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 with adjustments to previous estimates, which may be material, being recorded in the period that they become known.

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 cash generating units 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

The Company 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.

The PPA under which the Company's Kingsbridge1 power generation facility operates and the EPA under which the Quality Wind facility operates are accounted for as finance leases.

For other power generation plants operating under PPAs, their assets are accounted for as assets under operating leases.

Consolidation of subsidiaries that are less than wholly owned

The Company exercised judgment in determining that certain subsidiaries are controlled by the Company even though the subsidiaries are less than wholly owned.

Classification of joint arrangements structured through a separate vehicle

The Company exercised judgment in determining the classification of joint arrangements structured through separate vehicles as either joint operations or joint ventures.

Accounting Changes

Effective January 1, 2013

The Company adopted a number of new accounting standards, together with the consequential amendments to other standards, as issued by the International Accounting Standards Board (IASB). The changes that are significant to Capital Power are:

Standard	Description	Impact to Capital Power
Amendments to *IAS 1 Presentation of Financial Statements*	The amendments require entities to group items within other comprehensive income on the basis whether or not they will be reclassified to income or loss in a future period.	The Company's presentation within its statement of comprehensive income was amended.
IAS 36 *Impairment of Assets*	In May 2013, the IASB issued amendments to IAS 36 which require disclosure of the recoverable amount of impaired assets and additional disclosures about the measurement of the impaired assets when the recoverable amount is based on fair value less costs of disposal, including the discount rate when a present value technique is used to measure the recoverable amount.	The amendments are effective for annual periods beginning on or after January 1, 2014. However, the Company early adopted the amendments, on a retrospective basis, with insignificant impact to the Company's financial statement note disclosures.
Amendments to *IFRS 7 Financial Instruments: Disclosures*	The amendments establish additional disclosure requirements for the actual and potential effects of offsetting arrangements on the statement of financial position.	The Company added disclosures including the description and amounts of financial assets and financial liabilities subject to offsetting, enforceable master netting agreements or similar arrangements.
IFRS 12 *Disclosures of Interests in Other Entities*	This new and comprehensive standard requires additional financial statement disclosures for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities.	The Company disclosed the required information for its interests in joint arrangements and principal subsidiaries including summarized financial information for joint ventures and subsidiaries that have non-controlling interests.
IFRS 13 *Fair Value Measurement*	IFRS 13 defines fair value, sets out in a single IFRS a framework for measuring fair value, and expands disclosures about fair value measurements. IFRS 13 applies to fair value measurements required or permitted by other IFRSs but does not (a) introduce any new requirements to measure an asset or a liability at fair value, (b) change what is measured at fair value in IFRSs, or (c) address how to present changes in fair value.	The adoption of this new standard resulted in changes to the Company's fair value disclosures including details of the valuation techniques and process with respect to levels 2 and 3 of the fair value hierarchy

Future

The IASB issued the following amendments to existing standards that were not yet effective as of December 31, 2013.

Standard	Description	Impact to Capital Power	Effective Date
IFRS 9 *Financial Instruments* (Hedge Accounting and amendments to IFRS 9 and IFRS 7)	In November 2013, the IASB issued hedge accounting amendments which comprises part of its comprehensive project on financial instruments to replace IAS 39 *Financial Instruments: Recognition and Measurement.*	Potential application of hedge accounting to more hedging strategies based on new general hedge accounting model.	Pending IASB decision but tentative mandatory effective date for IFRS 9 of January 1, 2017

Financial Instruments

The Company has various financial assets that are classified for financial reporting purposes as available for sale, held at fair value through income or loss, or loans and receivable. Financial liabilities are classified as either held at fair value through income or loss or other liabilities. Initially, all financial assets and financial liabilities are recorded on the statement of financial position at fair value with subsequent measurement determined by the classification of each financial asset and liability. Trade and other receivables and trade and other payables are measured at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature.

The classification, carrying amounts and fair values of financial instruments held at December 31, 2013 and 2012 were as follows:

($millions)			As at December 31			
			2013		2012	
	Classification	**Fair value hierarchy level**	**Carrying amount**	**Fair value**	**Carrying amount**	**Fair value**
Financial assets:						
Cash and cash equivalents	Loans and receivables	n/a	100	100	53	53
Trade and other receivables	Loans and receivables	n/a	208	208	354	354
Derivative financial instruments assets – current and non-current	Financial assets designated at fair value through income or loss	See below	67	67	77	77
Finance lease receivables	Loans and receivables	Level 2	711	647	461	374
Other financial assets – current and non-current	Loans and receivables	Level 2	44	44	55	55
Financial liabilities:						
Trade and other payables	Other financial liabilities	n/a	198	198	210	210
Derivative financial instruments liabilities – current and non-current	Financial liabilities designated at fair value through income or loss	See below	41	41	64	64
Loans and borrowings (including current portion)	Other financial liabilities	Level 2	1,527	1,561	1,659	1,736

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 statement 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 stations 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 used for risk management purposes were measured at fair value and consisted of the following:

($millions)		As at December 31, 2013				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 1	-	-	-	-	-
	Level 2	29	37	1	-	67
	Level 3	-	-	-	-	-
		29	37	1	-	67
Derivative financial instruments liabilities	Level 1	-	-	-	-	-
	Level 2	(11)	(28)	(1)	(1)	(41)
	Level 3	-	-	-	-	-
		(11)	(28)	(1)	(1)	(41)
Net derivative financial instruments assets (liabilities)		**18**	**9**	**-**	**(1)**	**26**

($millions)		As at December 31, 2012				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 1	-	25	-	-	25
	Level 2	35	17	-	-	52
	Level 3	-	-	-	-	-
		35	42	-	-	77
Derivative financial instruments liabilities	Level 1	-	(30)	-	-	(30)
	Level 2	(6)	(12)	-	-	(18)
	Level 3	-	(16)	-	-	(16)
		(6)	(58)	-	-	(64)
Net derivative financial instruments assets (liabilities)		**29**	**(16)**	**-**	**-**	**13**

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 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.

Fair value measurement

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. These fair values are based partly on the key unobservable inputs of volatilities and correlations of the relative price changes in underlying prices. These volatilities and correlations are estimated using an exponentially-weighted moving average based on historical forward prices. Sensitivity analysis for significant Level 3 financial instruments is performed. The sensitivity analyses as at December 31, 2013 reflected negligible differences compared with their recorded fair values.

Disclosure Controls and Procedures and Internal Control over Financial Reporting

During the year ended December 31, 2013, the Company implemented a redesigned Enterprise Resource Planning (ERP) system to provide enhanced financial and other information to support its strategic plans and business operations. The implementation of the redesigned ERP system affected Capital Power's disclosure controls and internal controls over financial reporting. The evaluation of the changes to the design of the disclosure controls and internal controls over financial reporting concluded that there is reasonable assurance that material and required disclosure information is appropriately identified and reported and that financial reporting is reliable and in accordance with GAAP. The operation of the revised or new controls related to ERP implementation including internal controls over financial reporting were tested and evaluated.

As at December 31, 2013, 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) that 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, 2013, 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 1992 standards of the Committee of Sponsoring Organizations, a recognized control framework, and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

Quarterly Results

(GWh)	Three months ended							
Electricity generation	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**
Total generation excluding acquired Sundance PPA	3,925	4,317	3,746	4,142	4,159	4,575	3,499	4,222
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	463	480	493	481	272	507	453	399
Keephills 3	418	483	296	457	484	489	473	430
Clover Bar Energy Centre 1, 2 and 3	60	45	157	85	174	130	140	27
Joffre	95	109	109	101	65	87	97	92
Halkirk	137	76	118	135	44	n/a	n/a	n/a
Clover Bar Landfill Gas	5	4	4	3	7	8	9	8
Alberta commercial plants – owned	1,178	1,197	1,177	1,262	1,046	1,221	1,172	956
Acquired Sundance PPA	710	659	712	691	517	738	660	695
	1,888	1,856	1,889	1,953	1,563	1,959	1,832	1,651
Alberta contracted plants								
Genesee 1	842	819	482	807	830	755	767	814
Genesee 2	802	840	704	788	767	815	589	843
	1,644	1,659	1,186	1,595	1,597	1,570	1,356	1,657
Ontario and British Columbia contracted plants								
Island Generation	210	14	-	-	3	8	-	66
Kingsbridge 1	37	12	22	37	35	15	22	37
Port Dover and Nanticoke	54	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Quality Wind	113	68	88	108	70	n/a	n/a	n/a
Brown Lake	n/a	n/a	n/a	n/a	2	14	16	15
Miller Creek	n/a	n/a	n/a	n/a	1	22	16	4
	414	94	110	145	111	59	54	122
North East U.S. commercial plants								
Bridgeport	326	690	678	913	863	905	300	844
Rumford	10	57	32	25	15	229	87	33
Tiverton	155	434	409	55	389	416	354	452
	491	1,181	1,119	993	1,267	1,550	741	1,329
North Carolina U.S. contracted plants								
Roxboro	70	69	57	53	50	64	61	55
Southport	128	117	97	94	88	111	115	103
	198	186	154	147	138	175	176	158

(%)	Three months ended							
Plant availability	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**
Total average plant availability excluding acquired Sundance PPA	93	97	86	94	89	97	81	97
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	98	100	100	98	56	100	95	84
Keephills 3	99	100	65	98	100	100	100	95
Clover Bar Energy Centre 1, 2 and 3	91	93	99	99	98	97	97	98
Joffre	85	95	94	93	65	98	99	94
Halkirk	99	89	99	98	95	n/a	n/a	n/a
Clover Bar Landfill Gas	98	66	91	97	92	92	86	95
Alberta commercial plants – owned	94	96	91	97	81	99	98	93
Acquired Sundance PPA	89	83	93	97	74	97	90	95
	92	90	92	97	79	98	96	93
Alberta contracted plants								
Genesee 1	100	98	61	96	98	93	97	97
Genesee 2	95	100	86	94	94	99	72	100
	98	99	74	95	96	96	85	98
Ontario and British Columbia contracted plants								
Island Generation	99	100	100	100	100	100	100	100
Kingsbridge 1	94	95	96	99	100	99	99	99
Port Dover and Nanticoke	95	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Quality Wind	98	100	98	99	99	n/a	n/a	n/a
Brown Lake	n/a	n/a	n/a	n/a	100	99	100	99
Miller Creek	n/a	n/a	n/a	n/a	85	71	38	85
	98	99	99	99	100	97	94	98
North East U.S. commercial plants								
Bridgeport	72	93	83	97	85	95	35	96
Rumford	91	100	77	97	84	97	84	98
Tiverton	83	96	93	51	89	99	77	100
	79	95	84	86	86	97	58	98
North Carolina U.S. contracted plants								
Roxboro	98	97	88	94	89	97	84	96
Southport	91	99	94	96	90	100	87	96
	93	98	92	96	90	99	86	96

Financial results

(unaudited, $ millions)	Three months ended							
	Dec 31 2013	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**
Revenues								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	146	186	182	150	137	199	133	172
Alberta contracted plants	70	80	27	69	75	69	63	75
Ontario and British Columbia contracted plants	33	16	18	25	18	12	12	14
North East U.S. commercial plants and portfolio optimization	23	63	63	78	65	62	34	59
North Carolina U.S. contracted plants	19	20	17	15	16	19	18	18
Other portfolio activities	27	16	16	19	11	8	1	11
Corporate [1]	(9)	(4)	2	(2)	-	-	3	5
	309	377	325	354	322	369	264	354
Unrealized changes in fair value of commodity derivatives and Atlantic Power shares	18	3	(4)	11	(34)	18	(11)	14
	327	**380**	**321**	**365**	**288**	**387**	**253**	**368**
Adjusted EBITDA								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	50	105	114	81	64	113	55	87
Alberta contracted plants	53	55	7	44	51	38	35	45
Ontario and British Columbia contracted plants	26	9	12	20	15	8	9	10
North East U.S. commercial plants and portfolio optimization	(1)	11	7	4	(1)	12	1	13
North Carolina U.S. contracted plant	1	2	1	1	2	-	-	2
Other portfolio activities	7	(1)	(2)	(2)	(1)	4	-	7
Corporate	(34)	(31)	(30)	(26)	(30)	(31)	(27)	(25)
	102	150	109	122	100	144	73	139
Unrealized changes in fair value of commodity derivatives and Atlantic Power shares	17	1	(5)	13	(27)	7	(8)	13
	119	**151**	**104**	**135**	**73**	**151**	**65**	**152**

1 Revenues are offset by interplant category revenue eliminations.

Quarterly revenues, net income and funds provided by 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, and natural gas held for trading.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Dec 31 2013	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**
Revenues	327	380	321	365	288	387	253	368
Adjusted EBITDA [1]	119	151	104	135	73	151	65	152
Net income (loss)	98	59	23	48	19	63	(58)	66
Net income (loss) attributable to shareholders of the Company	77	44	20	34	15	39	(32)	40
Basic earnings (loss) per share ($)	0.89	0.55	0.20	0.44	0.19	0.55	(0.50)	0.66
Normalized earnings per share ($) [1]	0.35	0.72	0.27	0.36	0.23	0.55	0.07	0.46

[1] The consolidated financial information, except for adjusted EBITDA and normalized earnings per share, was prepared in accordance with GAAP. See Non-GAAP Financial Measures.

	Three months ended							
Spot price averages	**Dec 31 2013**	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**
Alberta power ($/MWh)	49	84	123	65	79	78	40	60
New England mass hub (US$/MWh)	35	42	40	86	45	37	29	33
Alberta natural gas (AECO) ($/Gj)	3.33	2.32	3.36	3.03	2.16	2.16	1.80	2.06
Capital Power's Alberta portfolio average realized power price ($/MWh)	64	94	93	69	65	81	60	83

Factors impacting the 2013 fourth quarter results

During the quarter ended December 31, 2013, the Company recorded net income attributable to shareholders of $77 million and normalized earnings per share of $0.35 which were significantly higher than the comparable amounts of $15 million and $0.23, respectively, in the fourth quarter of 2012. This increase in net income attributable to shareholders was primarily attributable to the after-tax gain on disposal of the North East U.S. subsidiaries, increased net unrealized gains in the fair value of commodity derivatives, and the impact of improved operating results at the plant level. Normalized earnings per share does not include the gain on disposal and the increased net unrealized gains in the fair value of commodity derivatives; thus, the increase primarily reflects plant operating factors including the non-recurrence of the 2012 realized losses on the Bridgeport heat rate option and the pricing of physical natural gas purchases for the Bridgeport plant.

The Port Dover and Nanticoke wind project commenced commercial operations in this quarter adding a total capacity of 105 MW to the Company's generation portfolio while the sale of the North East U.S. facilities decreased capacity by 1,089 MW. The Company recognized a pre-tax gain of $76 million on the sale of the North East U.S. facilities.

For the three months ended December 31, 2013, Alberta commercial plants and acquired Sundance PPA electricity generation was higher than experienced in the same quarter of 2012 primarily due to the 2012 planned outage at Genesee 3 which was extended by nine days. Similarly, the production associated with the acquired Sundance PPA was higher than production in the same quarter of 2012 when an outage occurred. Revenues reflected these plant operating factors offset by the impact of lower pricing in the Alberta marketplace. Adjusted EBITDA decreased on a quarter-over-quarter basis as portfolio optimization activities produced decreased results consistent with lower than expected power prices.

The portfolio of plants in the Ontario and British Columbia contracted plants category shifted as the Port Dover and Nanticoke wind facility commenced commercial operations on November 7, 2013 and the Halkirk and Quality Wind facilities produced a full quarter of operating results in 2013 compared with 2012. The increased plant base and Island Generation's increased production increased the number of MWh generated on a quarter-over-quarter basis, resulting in higher revenues and higher adjusted EBITDA. Island Generation was required by B.C. Hydro to run in the fourth quarter of 2013 although this does not significantly impact revenues and adjusted EBITDA for this plant since its deemed generation remained consistent. Availability of the plants in this category was strong for the periods of time that they were operated by Capital Power.

The 2013 fourth quarter results for the Bridgeport, Rumford and Tiverton plants in the North East U.S. commercial plants and portfolio optimization category were reflected to the date of sale of these facilities on November 19, 2013. The timing of the sale results in lower generation, revenues and adjusted EBITDA for these plants in the fourth quarter of 2013 compared with the same quarter in 2012. This impact on adjusted EBITDA was partly offset by the 2012 fourth quarter outage days experienced on a pre-emptive basis in consideration of Hurricane Sandy. Also, in the fourth quarter of 2013, net pre-tax losses of $10 million related to the North East U.S. plants were incurred. A heat rate option that was in place on the Bridgeport facility at the time of acquisition in 2011 settled at a loss for November and December 2012 due to a significant shift in the underlying locational basis risk associated with the option. The basis risk existed because the plant delivers power to and procures gas from locations differing from those referenced in the heat rate option. The correlation between the locations was historically very high for both power and natural gas. However, in November and December 2012, there was a spike in North East U.S. natural gas demand combined with supply constraints resulting in a significant shift in North East U.S. gas fundamentals. These factors led to a significant widening of the price spread between the Bridgeport plant's natural gas consumption point and the heat rate option location resulting in the loss. In addition, December 2012 physical natural gas consumption for Bridgeport was locked-in at prices higher than actual prices resulting in an additional loss. These losses were partly offset by gains realized on a financial hedge executed to reduce the locational basis risk. These trades were implemented to limit the exposure to the natural gas basis risk associated with the heat rate option.

Factors impacting results for previous quarters

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

Results of operations for the third quarter of 2013 were influenced by the Alberta spot power average price of $84/MWh and unplanned plant maintenance outages in the Alberta market. In particular, the high Alberta power prices favourably impacted the Alberta contracted plants' results. The Company announced its agreement with Emera Inc. to sell its North East U.S. plants. This decision to exit North East U.S. market was accompanied by the Company's decision to refocus its merchant power business in Alberta. As a result, the Company recognized a pre-tax impairment loss of $6 million and incurred pre-tax restructuring costs of $9 million in the third quarter of 2013. The purchase of the second tranche of the Company's interest in Shepard Energy Centre was completed during the quarter.

In the second quarter of 2013, Alberta commercial plants had strong results as power prices were driven higher when the Alberta market experienced several planned and unplanned outages. These positive results were partly offset by the results for Alberta contracted plants since Genesee 1 experienced a planned outage and both Genesee 1 and 2 experienced unplanned outages. These outages decreased production and the significant availability penalties incurred reflected the quarter's higher Alberta power prices.

The 2013 first quarter included the first full quarter of operations and results for Capital Power's Quality Wind and Halkirk wind projects. All plants, with the exception of Tiverton in the North East U.S., had relatively strong performance and financial results. Tiverton experienced an outage during the quarter when the maintenance work that was originally scheduled to be performed in the last half of 2013 was completed. The purchase of the first tranche in the Company's interest in Shepard Energy Centre was completed during the quarter.

In the fourth quarter of 2012, commercial operations of the Quality Wind and Halkirk wind projects commenced adding total capacity of 292 MW to the Company's generation portfolio. A pre-tax gain of $15 million was recorded on the sale of the Brown Lake and Miller Creek facilities. Results were negatively impacted by realized losses on the Bridgeport heat rate option and the pricing of physical gas purchases for the Bridgeport plant. These losses were partly offset by gains realized on a financial hedge executed to reduce the natural gas locational basis risk associated with the heat rate option. The net impact of these transactions was a pre-tax loss of $10 million. Planned outages occurred at Genesee 3 and Sundance. Adjusted EBITDA was positively impacted by approximately $9 million due to a change in the estimate of coal inventory for Genesee 1, 2 and 3.

In the third quarter of 2012, Alberta commercial plants experienced strong performance which was dampened by an unscheduled outage at Genesee 1 resulting from a trial project intended to increase the marketability of fly ash by-product.

In the second quarter of 2012, a pre-tax impairment loss of $74 million on Capital Power's North East U.S. plants based on reduced expected operating margins for the Bridgeport, Rumford and Tiverton plants largely as a result of weaker spark spreads in the Northeast U.S. power market was recognized. Results for the North East U.S commercial plants were impacted by lower than expected market spark spreads and an unplanned outage at the Bridgeport facility.

The 2012 first quarter reflected strong results for Alberta commercial plants and portfolio optimization largely due to the movement of Alberta power prices and their impact on portfolio position selling forward length at prices higher than the spot market. The production and contributions from Alberta commercial plants was strong with the inclusion of Keephills 3 since its commercial operations commenced in September 2011. The Company recognized significant unrealized net gains on its commodity derivatives due to the reversal of unrealized losses accrued at the previous year-end on contracts which settled in the first quarter of 2012 and the impact of decreasing Alberta forward power prices on its portfolio position.

Share and Partnership Unit Information

Quarterly common share trading information

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

	Three months ended							
	Dec 31 2013	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**
Share price ($/common share)								
High	21.95	22.22	22.55	23.53	23.20	24.53	24.47	25.72
Low	20.30	19.80	19.76	21.02	20.88	20.75	22.48	23.29
Close	21.30	21.26	20.58	21.20	22.73	21.29	23.78	23.49
Volume of shares traded (millions)	16.6	8.8	7.9	9.5	10.8	9.6	10.3	9.0

Outstanding share and partnership unit data

As at February 25, 2014, the Company had 81.293 million common shares outstanding, 18.841 million special voting 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 the redemption of all outstanding special voting shares in relation to the conversion of all outstanding exchangeable common limited partnership units of CPLP to common shares and ignoring exercise prices, the outstanding and issuable common shares as at February 25, 2014 were 104.300 million. All of the outstanding special voting shares and the one outstanding special limited voting share are held by EPCOR.

As at February 25, 2014, CPLP had 21.750 million general partnership units outstanding, 56.299 million common limited partnership units outstanding and 18.841 million exchangeable common limited partnership units outstanding, which are exchangeable for 18.841 million common shares of the Company. All of the outstanding general partnership units and the outstanding common limited partnership units are held, indirectly, by the Company. All of the outstanding exchangeable common limited partnership units are held by EPCOR.

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, 2013 and 2012

Management's responsibility for financial reporting

The preparation and presentation of the accompanying consolidated financial statements of Capital Power Corporation 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 28, 2014. 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 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

Stuart Lee
Senior Vice President, Finance and
Chief Financial Officer

February 28, 2014

CAPITAL POWER CORPORATION

Consolidated Financial Statements

Years ended December 31, 2013 and 2012

KPMG LLP
Chartered Accountants
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Edmonton AB T5J 3V8
Canada

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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, 2013 and December 31, 2012, 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, 2013 and December 31, 2012, 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 Accountants
February 28, 2014
Edmonton**,** Canada

CAPITAL POWER CORPORATION

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

Years ended December 31

	2013	2012
Revenues	$ 1,393	$ 1,296
Energy purchases and fuel	(560)	(533)
Gross margin	833	763
Other raw materials and operating charges (note 4)	(89)	(98)
Staff costs and employee benefits expense (note 4)	(147)	(143)
Depreciation and amortization (note 4)	(222)	(221)
Impairments (note 9)	(6)	(74)
Other administrative expenses (note 4)	(88)	(81)
Foreign exchange loss	(6)	-
Operating income	275	146
Gains on disposals of subsidiaries (note 8)	76	15
Finance expense (note 5)	(78)	(75)
Income before tax	273	86
Income tax (expense) recovery (note 6)	(45)	4
Net income	$ 228	$ 90
Attributable to:		
Non-controlling interests (note 31)	$ 53	$ 28
Shareholders of the Company	$ 175	$ 62

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

	2013	2012
Basic (note 7)	$ 2.13	$ 0.84
Diluted (note 7)	$ 2.08	$ 0.84

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

	2013	2012
Net income	$ 228	$ 90
Other comprehensive income (loss):		
Items that will not be reclassified subsequently to net income:		
Defined benefit plans:		
Actuarial gains (losses) [1]	2	(6)
Items that are or may be reclassified subsequently to net income:		
Cash flow hedges:		
Unrealized (losses) gains on derivative instruments [2]	(35)	54
Reclassification of losses (gains) on derivative instruments to income for the year [3]	27	(12)
Net investment in foreign subsidiaries:		
Unrealized gain (loss) [4]	23	(10)
Gains realized in net income on disposal of foreign subsidiary (note 8)	(59)	-
Total items that are or may be reclassified subsequently to net income, net of tax	(44)	32
Total other comprehensive (loss) income, net of tax	(42)	26
Total comprehensive income	$ 186	$ 116
Attributable to:		
Non-controlling interests (note 31)	$ 41	$ 42
Shareholders of the Company	$ 145	$ 74

[1] For the year ended December 31, 2013, net of income tax expense of $1. For the year ended December 31, 2012, net of income tax recovery of $2.

[2] For the year ended December 31, 2013, net of income tax recovery of $9. For the year ended December 31, 2012, net of income tax expense of $12.

[3] For the year ended December 31, 2013, net of reclassification of income tax recovery of $6. For the year ended December 31, 2012, net of reclassification of income tax expense of $2.

[4] For the years ended December 31, 2013 and December 31, 2012, net of income tax expense 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

	2013	2012
Assets		
Current assets:		
Cash and cash equivalents (note 10)	$ 100	$ 53
Trade and other receivables (note 11)	208	354
Inventories (note 12)	92	82
Derivative financial instruments assets (note 13)	31	47
Other financial assets (note 36)	10	-
	441	536
Non-current assets:		
Other assets	27	21
Derivative financial instruments assets (note 13)	36	30
Finance lease receivables (note 14)	711	461
Other financial assets (note 15)	36	57
Deferred tax assets (note 16)	95	70
Equity-accounted investment (note 32)	15	3
Intangible assets (note 17)	310	306
Property, plant and equipment (note 18)	3,525	3,628
Goodwill (note 19)	23	22
Total assets	$ 5,219	$ 5,134

Approved on behalf of the Board:

Donald Lowry
Director and Chairman of the Board

William Bennett
Director and Chairman of the Audit Committee

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

	2013	2012
Liabilities and equity		
Current liabilities:		
Trade and other payables (note 20)	$ 198	$ 210
Derivative financial instruments liabilities (note 13)	31	52
Loans and borrowings (note 21)	346	19
Deferred revenue and other liabilities	5	8
Provisions (note 22)	27	24
	607	313
Non-current liabilities:		
Derivative financial instruments liabilities (note 13)	10	12
Loans and borrowings (note 21)	1,181	1,640
Deferred revenue and other liabilities	89	91
Deferred tax liabilities (note 16)	180	112
Provisions (note 22)	148	214
	1,608	2,069
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 23)	2,328	1,903
Retained earnings (deficit)	83	(1)
Other reserves (note 24)	6	21
Retained earnings (deficit) and other reserves	89	20
	2,417	1,923
Non-controlling interests (note 31)	587	829
Total equity	3,004	2,752
Total liabilities and equity	$ 5,219	$ 5,134

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 23)	Cash flow hedges [1]	Cumulative translation account [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 31)	Total
Equity as at January 1, 2013	$ 1,903	$ 15	$ 10	$ (13)	$ 9	$ (1)	$ 1,923	$ 829	$ 2,752
Net income	-	-	-	-	-	175	175	53	228
Other comprehensive (loss) income:									
Defined benefit plan actuarial gains	-	-	-	3	-	-	3	-	3
Cash flow derivative hedge losses	-	(44)	-	-	-	-	(44)	-	(44)
Reclassification of losses to income	-	33	-	-	-	-	33	-	33
Unrealized gain on foreign currency translation	-	-	23	-	-	-	23	-	23
Gains realized on disposal of subsidiary (note 8)	-	-	(59)	-	-	-	(59)	-	(59)
Tax on items recognized directly in equity	-	3	-	(1)	-	-	2	-	2
Attributed to non-controlling interests (note 31)	-	3	9	-	-	-	12	(12)	-
Other comprehensive (loss) income	$ -	$ (5)	$ (27)	$ 2	$ -	$ -	$ (30)	$ (12)	$ (42)
Total comprehensive (loss) income	-	(5)	(27)	2	-	175	145	41	186
Issue of share capital	402	11	3	-	-	42	458	(258)	200
Share issue costs	(6)	-	-	-	-	-	(6)	-	(6)
Deferred taxes	2	-	-	-	-	(21)	(19)	-	(19)
Distributions to non-controlling interests	-	-	-	-	-	-	-	(33)	(33)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	8	8
Common share dividends (note 23)	-	-	-	-	-	(92)	(92)	-	(92)
Preferred share dividends (note 23)	-	-	-	-	-	(20)	(20)	-	(20)
Dividends reinvested	27	-	-	-	-	-	27	-	27
Share-based compensation	-	-	-	-	1	-	1	-	1
Equity as at December 31, 2013	$ 2,328	$ 21	$ (14)	$ (11)	$ 10	$ 83	$ 2,417	$ 587	$ 3,004

[1] Accumulated other comprehensive income (loss). Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income (loss) 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 23)	Cash flow hedges [1]	Cumulative translation account [1]	Defined benefit plan actuarial losses [1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests (note 31)	Total
Equity as at January 1, 2012	$ 1.499	$ (10)	$ 17	$ (7)	$ 8	$ 16	$ 1,523	$ 1,072	$ 2,595
Net income	-	-	-	-	-	62	62	28	90
Other comprehensive income (loss):									
Defined benefit plan actuarial losses	-	-	-	(8)	-	-	(8)	-	(8)
Cash flow derivative hedge gains	-	66	-	-	-	-	66	-	66
Reclassification of gains to income	-	(14)	-	-	-	-	(14)	-	(14)
Unrealized loss on foreign currency translation	-	-	(10)	-	-	-	(10)	-	(10)
Tax on items recognized directly in equity	-	(10)	-	2	-	-	(8)	-	(8)
Attributed to non-controlling interests (note 31)	-	(17)	3	-	-	-	(14)	14	-
Other comprehensive income (loss)	$ -	$ 25	$ (7)	$ (6)	$ -	$ -	$ 12	$ 14	$ 26
Total comprehensive income (loss)	-	25	(7)	(6)	-	62	74	42	116
Issue of share capital	389	-	-	-	(1)	12	400	(253)	147
Share issue costs	(5)	-	-	-	-	-	(5)	-	(5)
Deferred taxes	1	-	-	-	-	-	1	-	1
Distributions to non-controlling interests	-	-	-	-	-	-	-	(39)	(39)
Net additional investment by non-controlling interests	-	-	-	-	-	-	-	7	7
Common share dividends (note 23)	-	-	-	-	-	(85)	(85)	-	(85)
Preferred share dividends (note 23)	-	-	-	-	-	(6)	(6)	-	(6)
Dividends reinvested	19	-	-	-	-	-	19	-	19
Share-based compensation	-	-	-	-	2	-	2	-	2
Equity as at December 31, 2012	$ 1,903	$ 15	$ 10	$ (13)	$ 9	$ (1)	$ 1,923	$ 829	$ 2,752

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

	2013	2012
Cash flows from operating activities:		
Net income	$ 228	$ 90
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization (note 4)	222	221
Gains on disposals (note 8)	(76)	(15)
Impairments (note 9)	6	74
Finance expense (note 5)	78	75
Fair value changes on derivative instruments (note 13)	(26)	11
Income tax expense (recovery) (note 6)	45	(4)
Other items	6	(4)
Interest paid [1]	(67)	(59)
Income taxes recovered (paid)	10	(7)
Change in non-cash operating working capital (note 25)	71	(140)
Net cash flows from operating activities	497	242
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(943)	(598)
Proceeds on disposal of assets	570	116
Other cash flows from investing activities	25	16
Net cash flows used in investing activities	(348)	(466)
Cash flows (used in) from financing activities:		
Proceeds from issue of loans and borrowings	-	250
Repayment of loans and borrowings	(155)	(62)
Issue costs on loans and borrowings	(1)	(3)
Proceeds from issue of common shares (note 23)	-	8
Proceeds from issue of preferred shares (note 23)	200	150
Share issue costs (note 23)	(6)	(5)
Distributions paid to non-controlling interests (notes 26 and 31)	(36)	(42)
Common share dividends paid (note 23)	(62)	(62)
Preferred share dividends paid (note 23)	(20)	(6)
Interest paid [1]	(21)	(23)
Net cash flows (used in) from financing activities	(101)	205
Foreign exchange losses on cash held in a foreign currency	(1)	(1)
Net increase (decrease) in cash and cash equivalents	47	(20)
Cash and cash equivalents at beginning of year	53	73
Cash and cash equivalents at end of year	$ 100	$ 53

[1] Total interest 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 plants and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities.

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

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 28, 2014.

(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 an approximate 81% interest in Capital Power L.P. (CPLP) (December 31, 2012 – 71%). Based on an assessment of the relationship between Capital Power and CPLP as disclosed in note 31, Capital Power controls CPLP and therefore CPLP is treated as a subsidiary of Capital Power. EPCOR Utilities Inc. (EPCOR) holds a non-controlling interest in CPLP as described in note 31.

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) Changes in accounting policies:

Effective January 1, 2013, the Company adopted a number of new accounting standards, together with the consequential amendments to other IFRSs. These standards, along with the impacts of the changes to the Company’s consolidated financial statements are as follows:

IAS 1 – Presentation of Financial Statements – The amendments to IAS 1 require entities to group items within other comprehensive income on the basis of whether or not they will be reclassified to income or loss in a future period. The Company’s presentation within its statement of other comprehensive income has been amended accordingly.

IFRS 7 – Financial Instruments: Disclosures – The amendments to IFRS 7 establish additional disclosure requirements for the actual and potential effects of offsetting arrangements on the Company’s statements of financial position. The adoption of the amendments to IFRS 7 has resulted in the additional disclosures regarding offsetting of financial assets and liabilities in note 28.

2. Significant accounting policies, continued:

(c) Changes in accounting policies, continued:

IFRS 12 – Disclosures of Interests in Other Entities - This new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities has resulted in additional financial statement disclosures relating to interests in subsidiaries and joint arrangements in these consolidated financial statements. The adoption of this standard has resulted in the additional disclosures regarding interests in other entities in note 31 and regarding joint arrangements in note 32.

IFRS 13 – Fair Value Measurement – IFRS 13 defines fair value, sets out in a single IFRS a framework for measuring fair value and enhances disclosures about fair value measurements. IFRS 13 applies to fair value measurements required or permitted by other IFRSs, but does not (a) introduce any new requirements to measure an asset or a liability at fair value, (b) change what is measured at fair value in IFRSs, or (c) address how to present changes in fair value. The adoption of this new standard resulted in changes to the Company's fair value disclosures in note 28, including the requirement to include such disclosures within the notes to the Company's interim consolidated financial statements.

IAS 36 – Impairment of Assets - In May 2013, the IASB issued amendments to IAS 36 which require disclosure of the recoverable amount of impaired assets and additional disclosures about the measurement of the impaired assets when the recoverable amount is based on fair value less costs of disposal, including the discount rate when a present value technique is used to measure the recoverable amount. The amendments are effective for annual periods beginning on or after January 1, 2014. Earlier application is permitted. During the year ended December 31, 2013, the Company has early adopted, on a retrospective basis, these amendments, which did not have a significant impact on the Company's note disclosures.

The Company also adopted other relevant standards effective January 1, 2013 that did not have a significant impact on the Company's financial statements and note disclosures thereto.

(d) 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.

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.

2. Significant accounting policies, continued:

(d) Business combinations and goodwill, continued:

Goodwill, continued

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

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.

(e) 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 have 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. The accounting policies of the joint venture are aligned with the accounting policies of the Company.

(f) 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.

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.

2. Significant accounting policies, continued:

(g) 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(h). 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.

Monetary contributions received from third parties used to either connect a customer to a network or to provide the customer 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.

(h) 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. Such types of 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.

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 value.

2. Significant accounting policies, continued:

(h) Leases or arrangements containing a lease, continued:

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 on a straight-line basis over the life of the lease. The Company has not entered into any finance lease arrangements as a lessee.

(i) 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 28.

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 2014 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(p). 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.

Other financial liabilities

The Company's loans and borrowings 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.

2. Significant accounting policies, continued:

(j) 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.

All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used, in which case changes in the fair value of the effective portion of the derivatives are recorded in other comprehensive income.

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.

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.

2. Significant accounting policies, continued:

(j) Derivative instruments and hedging activities, continued:

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.

The Company may use non-financial or financial commodity derivative trades 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. Such trades are recognized on a net basis in the Company's revenues.

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.

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 gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the period.

2. Significant accounting policies, continued:

(j) Derivative instruments and hedging activities, continued:

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.

(k) 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.

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 plants 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.

(l) 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 17 for additional discussion on intangible assets.

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

2. Significant accounting policies, continued:

(l) Intangible assets, continued:

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 plant 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 plant. 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 PPAs	12 to 17 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.

(m) Development costs:

Development activities involve a plan or design for the production of new or substantially improved products and processes. Development expenditures are capitalized only if development costs can be measured reliably, the product or process is technically and commercially feasible, 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 expenditures are recognized in income or loss as incurred.

Capitalized development expenditures are measured at cost less accumulated amortization and accumulated impairment losses.

(n) 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.

(o) 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.

2. Significant accounting policies, continued:

(o) Impairment of non-financial assets, continued:

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 based on estimated market values based on 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.

(p) 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.

2. Significant accounting policies, continued:

(q) Income taxes:

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

Current income taxes for the current period, including any adjustments to taxes payable in respect of previous years, are recognized and measured at the amount expected to be recovered from or payable to the taxation authorities based on the tax rates that are enacted or substantively enacted by the end of the reporting period.

Deferred income tax assets and liabilities are recognized for temporary differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases using the tax rates that are expected to apply in the period in which the deferred tax asset or liability is expected to settle, based on the laws that have been enacted or substantively enacted by the reporting date. Such deferred tax assets and liabilities are not recognized if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable income nor the accounting income. Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which they can be utilized. Deferred tax assets are reviewed at each reporting date and reduced accordingly to the extent that it is no longer probable that they can be utilized.

Deferred tax liabilities are recognized for taxable temporary differences associated with investments in subsidiaries, and interests in joint ventures, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests are only recognized to the extent that it is probable that there will be sufficient taxable income against which to utilize the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

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

(r) 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. The fair values of the Company’s emission credits fall within Level 1 of the Company’s fair value hierarchy described in note 28. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstance.

(s) 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.

(t) Government assistance:

Government assistance is recognized when there is reasonable assurance that the Company will comply with the conditions attached to the government assistance and the grants will be received. Such assistance is recorded either as a reduction to the related expense or, where related to an asset, as deferred revenue and amortized over the useful life of the related asset.

2. Significant accounting policies, continued:

(u) 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. Accretion of the liability is recorded in finance expense.

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.

(v) 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 for directors under a Directors' Deferred Share Unit (DSU) Plan. The fair values of the amounts payable to employees/directors in respect of the PSU 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.

(w) 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.

2. Significant accounting policies, continued:

(x) Future accounting changes:

A number of new standards, and amendments to standards and interpretations are not yet effective for the year ended December 31, 2013 and have not been applied in preparing these consolidated financial statements. Based on the Company's preliminary assessment, those standards which are expected to have a significant effect on its consolidated financial statements are described below. For those standards where earlier application is permitted, the Company expects to apply the changes at the effective date.

IFRS 9 – Financial Instruments – In November 2013, the IASB issued amendments to IFRS 9 – Financial instruments which address the classification and measurement requirements of financial assets and liabilities, improve transparency in the disclosure of expected credit losses and improve the overall usefulness of financial statements for users by revising the current hedge accounting requirements. The effective dates of the changes are to be determined and are to be applied retrospectively. Earlier application is permitted.

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(h), 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 14.

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 31.

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 32.

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:

Financial instruments

The valuation of the Company's derivative instruments and certain other financial instruments requires estimation of the fair value of each instrument at the reporting date. Details of the basis on which fair values are estimated are provided in notes 13 and 28.

Non-financial assets

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.

For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. 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. Goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the CGUs that are expected to benefit from the acquisition.

Estimates of fair value for the recoverable amount of CGUs undergoing impairment testing, and for purchase price allocations for business combinations, are primarily based on discounted cash flow projection techniques employing estimated future cash flows based on assumptions regarding the expected market outlook and cash flows from each CGU or asset. The cash flow estimates will vary with the circumstances of the particular assets or CGU and will be based on, among other things, the lives of the assets, contract prices, estimated future prices, revenues and expenses, including growth rates and inflation, and required capital expenditures. Details of the key estimates used in assessing the recoverable amount of each CGU at the last impairment review date are provided in note 9. Market capitalization and comparative market multiples, where available, are used to corroborate management's discounted cash flow projections.

Decommissioning and other provisions

Measurement of the Company's provisions and the related change in discount rate require the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required and related future cash flows for the decommissioning provisions and estimates of expected customer renewals for the Company's other provisions. The key assumptions used in determining these provisions are provided in note 22.

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 16.

Revenue recognition

As noted in note 2(g), 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.

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

4. Expenses:

	2013	2012
Included in other raw materials and operating charges		
Development costs	$ -	$ 1
Included in staff costs and employee benefits expense		
Share-based payments (note 27)	4	3
Post-employment defined contribution plan expense	8	8
Post-employment defined benefit plan expense	5	3
Included in depreciation and amortization		
Depreciation of property, plant and equipment (note 18)	185	198
Amortization of intangible assets (note 17)	21	17
Losses on retirement of property, plant and equipment	7	5
Other	9	1
	222	221
Included in other administrative expenses		
Operating lease payments	5	5

5. Finance expense:

	2013	2012
Interest expense:		
Interest on loans and borrowings	$ 89	$ 87
Capitalized interest	(21)	(23)
Total interest expense	68	64
Other finance expense:		
Gain on interest rate non-hedges (note 13)	-	(1)
Unwinding of the discount on decommissioning provisions (note 22)	4	4
Other	6	8
Finance expense	$ 78	$ 75

6. Income tax:

	2013	2012
Current income tax		
Current income tax (recovery) expense	$ (4)	$ 4
Deferred income tax		
Relating to origination and reversal of temporary differences	42	(3)
Relating to prior periods	(5)	2
Relating to write-downs of deferred tax assets	12	(7)
Total deferred income tax expense (recovery)	49	(8)
Income tax expense (recovery)	$ 45	$ (4)

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

6. Income tax, continued:

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

	2013	2012
Income before tax	$ 273	$ 86
Income tax at the statutory rate of 25.0%	68	22
Increase (decrease) resulting from		
Amounts attributable to non-controlling interests	(9)	(12)
Amounts relating to gains on disposals	10	5
Change in unrecognized tax benefits	(4)	(7)
Non-(taxable) deductible amounts	(5)	5
Prior period tax adjustments	(5)	2
Statutory and other rate differences	(9)	(20)
Other	(1)	1
Income tax expense (recovery)	$ 45	$ (4)

7. 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:

	2013	2012
Income for the period attributable to shareholders of the Company	$ 175	$ 62
Preferred share dividends of the Company [1]	(20)	(6)
Earnings used in the calculation of basic earnings per share	$ 155	$ 56

[1] Includes preferred share dividends declared in respect of the years ended December 31, 2013 and 2012 respectively.

	2013	2012
Weighted average number of common shares used in the calculation of basic earnings per share	72,818,513	66,818,697

Diluted earnings per share

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

	2013	2012
Earnings used in the calculation of basic earnings per share	$ 155	$ 56
Effect of exchangeable limited partnership units issued to EPCOR for common shares [2]	51	-
Earnings used in the calculation of diluted earnings per share	$ 206	$ 56

[2] The exchangeable limited partnership units issued to EPCOR may be exchanged for common shares of Capital Power on a one-for-one basis. For the year ended December 31, 2013, the potential exchange of such units for common shares of the Company had a dilutive impact as the potential exchange would remove the attribution of net income to non-controlling interests related to CPLP of $65 million. Additionally, the income tax provision of the Company would need to be adjusted to reflect the non-controlling interest's share of CPLP income tax expenses of $14 million. For the year ended December 31, 2012, the potential exchange of such units for common shares of the Company was not included in the calculation of diluted earnings per share as it was anti-dilutive.

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

7. Earnings per share, continued:

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:

	2013	2012
Weighted average number of common shares used in the calculation of basic earnings per share	72,818,513	66,818,697
Effect of dilutive share purchase options [1]	-	-
Effect of exchangeable limited partnership units issued to EPCOR for common shares	26,047,575	-
Weighted average number of common shares used in the calculation of diluted earnings per share	98,866,088	66,818,697

[1] For the years ended December 31, 2013 and December 31, 2012, the average market price of the Company's common shares was below the exercise price of all granted share purchase options described in note 27 and as a result none of the share purchase options had a dilutive effect on earnings per share.

8. Disposal of subsidiaries:

The gains recognized on disposals of subsidiaries were as follows:

	2013	2012
North East U.S. assets	$ 76	$ -
Brown Lake and Miller Creek assets (hydro assets)	-	15
Gains on disposals	$ 76	$ 15

On November 19, 2013, the Company completed the sale to a third party of one hundred percent of Capital Power's equity interests in Bridgeport Energy, LLC, Tiverton Power, LLC, and Rumford Power Inc. (the North East U.S. assets) for gross proceeds of $577 million (US$550 million) less transaction costs of $8 million (US$8 million). The gross proceeds at the close of the transaction included $9 million (US$9 million) of working capital adjustments. Subsequent to the close of the transaction, the proceeds relating to working capital adjustments were reduced by $1 million (US$1 million) and this reduction has been recorded as an accrued liability within trade and other payables at December 31, 2013.

Prior to close of the transaction, accumulated foreign currency translation gains of $59 million relating to the North East U.S. assets were included in accumulated other comprehensive income within other reserves on the consolidated statements of financial position. These amounts were reclassified to net income, within the gain on disposal, upon close of the transaction.

The carrying amounts of the assets and liabilities of the North East U.S. assets at the time of disposal were as follows:

	November 19, 2013
Trade and other receivables	$ 4
Inventories	9
Intangible assets	15
Property, plant and equipment	592
Trade and other payables	(12)
Deferred tax liabilities	(20)
Provisions – non-current	(37)
Carrying amount of net assets disposed	$ 551

9. Impairment testing:

The Company reviews its CGUs that contain goodwill on an annual basis, generally in the third quarter, to determine whether any impairments should be recognized. As a result, the Company's Southport CGU was tested for impairment during the third quarter of 2013. The estimated recoverable amount of the Southport CGU exceeded its carrying amount and as such, no impairment was required.

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

9. Impairment testing, continued:

In addition to the annual testing noted above, the Company tested its North East U.S. commercial plants and portfolio optimization CGU (North East U.S. CGU) for impairment during the third quarter of 2013, immediately prior to classifying those assets as held for sale, in advance of the disposal described in note 8. The carrying amount of the North East U.S. CGU was in excess of the estimated recoverable amount resulting in a $6 million pre-tax impairment recorded in 2013 within the U.S. geographic area.

Impairments recognized in the years ended December 31, 2013 and 2012, respectively, were as follows:

	2013	2012
Property, plant and equipment (note 18)	$ 6	$ 50
Goodwill (note 19)	-	24
Total impairments	$ 6	$ 74

Key assumptions used in calculating recoverable amounts

The recoverable amount of the North East U.S. CGU was based on its fair value less costs to sell as established by the proceeds set out in the transaction described in note 8, less expected transaction costs. The fair value measurement of the North East U.S. CGU is categorized in Level 1 of the fair value hierarchy, as described in note 28.

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 28, 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:

	2013	2012
Discount rate – currently contracted period	7.9%	7.5%
Discount rate – post current contract period	9.9%	10.5%
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 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 and 50% tire-derived fuel (TDF), and will execute long-term contracts with wood waste and TDF suppliers at prices consistent with current rates, adjusted for inflation.

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

9. Impairment testing, continued:

Key assumptions used in calculating recoverable amounts, continued:

Other key cash flow assumptions, continued

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.

10. Cash and cash equivalents:

	December 31, 2013	December 31, 2012
Cash and cash equivalents	$ 100	$ 53

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 $30 million (December 31, 2012 - $10 million).

11. Trade and other receivables:

	December 31, 2013	December 31, 2012
Accrued revenues	$ 143	$ 135
Trade receivables	19	127
Receivables from related parties (note 26)	6	8
Finance lease receivable (note 14)	21	13
Allowance for doubtful accounts (note 29)	-	(2)
Net trade receivables	189	281
Income taxes recoverable	12	13
Deposits on acquisition	-	50
Prepayments	7	10
	$ 208	$ 354

Details of the aging of trade receivables and analysis of the movement on the allowance for doubtful accounts are provided in note 29.

12. Inventories:

	December 31, 2013	December 31, 2012
Parts and other consumables	$ 50	$ 54
Coal	19	18
Emission credits	23	10
	$ 92	$ 82

Inventories expensed upon usage for the year ended December 31, 2013 of $133 million (year ended December 31, 2012 - $130 million) were charged to energy purchases and fuel, and other raw materials and operating charges. No write-downs of inventories were recognized in the year ended December 31, 2013 (year ended December 31, 2012 - nil). There were no reversals of previous write downs recognized in the year ended December 31, 2013 (year ended December 31, 2012 - nil). As at December 31, 2013, no inventories were pledged as security for liabilities (December 31, 2012 - nil).

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

13. 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 29 consist of the following:

	December 31, 2013				
	Energy		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 7	$ 24	$ -	$ -	$ 31
Non-current	22	13	1	-	36
Derivative instruments liabilities:					
Current	(6)	(23)	(1)	(1)	(31)
Non-current	(5)	(5)	-	-	(10)
Net fair value	$ 18	$ 9	$ -	$ (1)	$ 26
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(10)	(4)			
Gigajoules of natural gas (millions)	-	1			
Cross currency swaps and interest rate swaps (millions of U.S. dollars)			$ 195	$ 100	
Range of remaining contract terms in years	0.1 to 5.0	0.1 to 5.0	7.5 to 12.5	7.5	

	December 31, 2012		
	Energy		
	cash flow hedges	non-hedges	Total
Derivative instruments assets:			
Current	$ 12	$ 35	$ 47
Non-current	23	7	30
Derivative instruments liabilities:			
Current	(2)	(50)	(52)
Non-current	(4)	(8)	(12)
Net fair value	$ 29	$ (16)	$ 13
Net notional buys (sells):			
Megawatt hours of electricity (millions)	(6)	-	
Gigajoules of natural gas (millions)	-	2	
Range of remaining contract terms in years	0.1 to 5.0	0.1 to 5.0	

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

13. Derivative financial instruments and hedge accounting, continued:

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.

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

	2013		2012	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (11)	$ (34)	$ 52	$ 14
Energy non-hedges	26	129	(11)	24
Foreign exchange cash flow hedges	-	-	-	-
Foreign exchange non-hedges	-	(1)	-	-
Interest rate non-hedges	(1)	1	8	(7)

Realized 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, 2013 and 2012:

	2013	2012
Revenues	$ 199	$ 48
Energy purchases and fuel	(78)	(21)
Foreign exchange losses	(1)	-
Finance expense	-	1

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. 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.

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity and natural gas prices and certain derivatives it uses to manage currency risk relating to U.S. dollar denominated loans and borrowings. For the year ended December 31, 2013, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statement of income was nil (year ended December 31, 2012 - nil).

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

13. Derivative financial instruments and hedge accounting, continued:

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

	December 31, 2013
Within one year	$ 1
Between one and five years	13
After five years	-
	$ 14

The Company's cash flow hedges extend to 2018 for energy cash flow hedges and to 2026 for foreign exchange cash flow hedges.

14. Leases:

Finance lease receivables

	Minimum lease payments		Present value of minimum lease payments	
	December 31, 2013	December 31, 2012	December 31, 2013	December 31, 2012
Amounts receivable under finance leases:				
Less than one year	$ 57	$ 31	$ 18	$ 13
Between one and five years	229	123	82	57
More than five years	981	571	632	404
Unearned finance income	(535)	(251)	-	-
Lease payment receivable	732	474	732	474
Less current portion: (included within trade and other receivables (note 11))	21	13	21	13
	$ 711	$ 461	$ 711	$ 461

The PPAs pertaining to the Company's wind generation facilities located in Ontario (Kingsbridge and Port Dover and Nanticoke) and British Columbia (Quality Wind) expire in 2026, 2033 and 2037 respectively and have effective rates inherent in the leases of 3.21%, 6.77% and 4.86% respectively. The lease receivables contain unguaranteed residual values of $13 million, $43 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 28.

Finance income of $20 million was recognized in revenues during the year ended December 31, 2013 (year ended December 31, 2012 - $5 million).

Plants under operating leases

Certain power generation plants operate under PPAs that convey the right to the holder of the agreement to use the related property plant and equipment. Consequently, these power generation assets held by subsidiaries of the Company, comprised of the Roxboro, Genesee units 1 and 2 and Island Generation power generation assets are accounted for as assets under operating leases. During the comparative period, through to the disposal of the hydro assets in October 2012, the Miller Creek and Brown Lake power generation assets were also accounted for as assets under operating leases.

As at December 31, 2013 the cost of such property, plant and equipment was $1,188 million (December 31, 2012 - $1,220 million), less accumulated depreciation of $224 million (December 31, 2012 - $186 million).

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

14. Leases, continued:

Plants under operating leases, continued

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

	December 31, 2013
Within one year	$ 60
Between one and five years	245
After five years	144
	$ 449

15. Other financial assets:

	December 31, 2013	December 31, 2012
Other financial assets – non-current:		
Loans and other long-term receivables	$ 34	$ 55
Available for sale - portfolio investments	2	2
	$ 36	$ 57

16. Deferred tax:

Deferred tax assets and liabilities are attributable to the following as at December 31, 2013 and 2012:

	Assets		Liabilities		Net	
	2013	2012	2013	2012	2013	2012
Losses carried forward	$ 84	$ 59	$ -	$ -	$ 84	$ 59
Difference in accounting and tax basis of property, plant and equipment	6	-	(87)	(110)	(81)	(110)
Difference in accounting and tax basis of intangible assets	42	35	(22)	(20)	20	15
Deferred partnership income	4	18	-	-	4	18
Derivative instruments	11	22	(16)	(20)	(5)	2
Share issue costs and deferred financing charges	5	7	-	-	5	7
Other financial assets	-	-	-	(4)	-	(4)
Deferred revenue and other liabilities	20	18	-	-	20	18
Finance lease receivables	-	-	(148)	(84)	(148)	(84)
Decommissioning provisions	27	43	-	-	27	43
Goodwill	-	-	(8)	(8)	(8)	(8)
Prepaid reclamation amounts	-	-	(14)	(12)	(14)	(12)
Other provisions	9	11	-	-	9	11
Loans and borrowings	-	-	(1)	-	(1)	-
Other assets	3	3	-	-	3	3
Deferred tax assets (liabilities)	$ 211	$ 216	$ (296)	$ (258)	$ (85)	$ (42)
Set off of tax	(116)	(146)	116	146	-	-
Net deferred tax assets (liabilities)	$ 95	$ 70	$ (180)	$ (112)	$ (85)	$ (42)

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

16. Deferred tax, continued:

Movement in temporary differences during the year ended December 31, 2013:

	As at January 1, 2013	Recognized in net income	Recognized directly in other comprehensive income	Amounts relating to gains on acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2013
Losses carried forward	$ 59	$ 22	$ 4	$ -	$ 7	$ (8)	$ 84
Difference in accounting and tax basis of property, plant and equipment	(110)	6	(2)	25	-	-	(81)
Difference in accounting and tax basis of intangible assets	15	19	-	(14)	-	-	20
Deferred partnership income	18	(14)	-	-	-	-	4
Derivative instruments	2	(8)	3	(2)	-	-	(5)
Share issue costs and deferred financing charges	7	(4)	-	-	2	-	5
Other financial assets	(4)	5	-	(1)	-	-	-
Deferred revenue and other liabilities	18	-	-	2	-	-	20
Finance lease receivables	(84)	(52)	-	(12)	-	-	(148)
Decommissioning provisions	43	(21)	2	3	-	-	27
Goodwill	(8)	-	-	-	-	-	(8)
Prepaid reclamation amounts	(12)	-	-	(2)	-	-	(14)
Other provisions	11	(1)	(1)	-	-	-	9
Loans and borrowings	-	(1)	-	-	-	-	(1)
Other assets	3	-	-	-	-	-	3
	$ (42)	$ (49)	$ 6	(1)	$ 9	$ (8)	$ (85)

Movement in temporary differences during the year ended December 31, 2012:

	As at January 1, 2012	Recognized in net income	Recognized directly in other comprehensive income	Amounts relating to gains on acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2012
Losses carried forward	$ 35	$ 24	$ -	$ -	$ -	$ -	$ 59
Difference in accounting and tax basis of property, plant and equipment	(142)	41	-	(9)	-	-	(110)
Difference in accounting and tax basis of intangible assets	22	(10)	-	3	-	-	15
Deferred partnership income	(6)	24	-	-	-	-	18
Derivative instruments	4	7	(10)	1	-	-	2
Share issue costs and deferred financing charges	10	(6)	-	-	1	2	7
Other financial assets	-	(4)	-	-	-	-	(4)
Deferred revenue and other liabilities	14	2	-	2	-	-	18
Finance lease receivables	(9)	(74)	-	(1)	-	-	(84)
Decommissioning provisions	38	3	-	2	-	-	43
Goodwill	(8)	-	-	-	-	-	(8)
Prepaid reclamation amounts	(10)	-	-	(2)	-	-	(12)
Other provisions	9	-	2	-	-	-	11
Other assets	2	1	-	-	-	-	3
	$ (41)	$ 8	$ (8)	(4)	$ 1	$ 2	$ (42)

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

16. Deferred tax, continued:

As at December 31, 2013 the Company has non-capital losses carried forward of approximately $294 million (December 31, 2012 - $178 million), of which $236 million (December 31, 2012 - $160 million) relate to certain U.S. subsidiaries. These losses expire between 2024 and 2033. Of the non-capital losses relating to certain U.S. subsidiaries, $108 million (December 31, 2012 - $101 million) are subject to an annual limitation under Internal Revenue Code Section 382. As at December 31, 2013, the Company has no capital losses for income tax purposes (December 31, 2012 - nil). The deferred tax assets presented on the consolidated statements of financial position are recoverable based on estimated future earnings. The assumptions used in the estimate of future earnings are based on the Company's long-range forecasts. There are non-capital losses available to be carried forward of $38 million (December 31, 2012 - $17 million) and other deductible temporary differences of $155 million (December 31, 2012 - $119 million) for which no tax benefit has been recognized. Included in the amounts relating to the gain on disposal is $16 million (December 31, 2012 – nil) of tax expense relating to a write-down of a deferred tax asset.

17. Intangible assets:

	Intangible work in progress	PPAs	Contract rights	Customer rights	Other rights	Emission credits	Software	Total
Cost								
As at January 1, 2012	$ 7	$ 140	$ 29	$ 4	$ 107	$ 32	$ 17	$ 336
Additions from separate acquisition	18	-	7	-	7	26	-	58
Additions into service	(13)	-	-	-	-	-	13	-
Disposal of hydro assets	-	-	-	(4)	-	-	-	(4)
Other disposals	-	-	(1)	-	-	(25)	(4)	(30)
As at December 31, 2012	$ 12	$ 140	$ 35	$ -	$ 114	$ 33	$ 26	$ 360
Additions from separate acquisition	39	-	-	-	2	27	3	71
Additions into service	(13)	-	-	-	-	-	13	-
Disposal of North East U.S. assets (note 8)	-	-	-	-	-	(15)	-	(15)
Other disposals	-	-	-	-	-	(7)	-	(7)
Transfers to finance lease receivables	(8)	-	-	-	(7)	-	-	(15)
Transfers to inventory	-	-	-	-	-	(9)	-	(9)
As at December 31, 2013	$ 30	$ 140	$ 35	$ -	$ 109	$ 29	$ 42	$ 385
Accumulated amortization								
At January 1, 2012	$ -	$ (31)	$ (1)	$ -	$ (3)	$ -	$ (5)	$ (40)
Other disposals	-	-	-	-	-	-	3	3
Amortization	-	(12)	-	-	(2)	-	(3)	(17)
As at December 31, 2012	$ -	$ (43)	$ (1)	$ -	$ (5)	$ -	$ (5)	$ (54)
Other disposals	-	-	-	-	-	-	-	-
Amortization	-	(12)	(2)	-	(2)	-	(5)	(21)
As at December 31, 2013	$ -	$ (55)	$ (3)	$ -	$ (7)	$ -	$ (10)	$ (75)
Net book value								
As at January 1, 2012	$ 7	$ 109	$ 28	$ 4	$ 104	$ 32	$ 12	$ 296
As at December 31, 2012	$ 12	$ 97	$ 34	$ -	$ 109	$ 33	$ 21	$ 306
As at December 31, 2013	$ 30	$ 85	$ 32	$ -	$ 102	$ 29	$ 32	$ 310

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.

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

17. Intangible assets, continued:

Other rights include the cost of land lease agreements for use in wind power projects in Alberta, British Columbia and Ontario 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, 2013 (year ended December 31, 2012 - nil). No previous impairments of intangible assets were reversed during the year ended December 31, 2013 (year ended December 31, 2012 - nil).

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the years ended December 31, 2013 or 2012.

Restrictions on assets

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

18. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment	Total
Cost				
As at January 1, 2012	$ 358	$ 87	$ 3,710	$ 4,155
Additions	504	-	15	519
Additions into service	(359)	17	342	-
Disposal of hydro assets	-	-	(71)	(71)
Retirements and other disposals	-	-	(53)	(53)
Transfers to finance lease receivables	(412)	-	-	(412)
Revisions to decommissioning costs	-	-	9	9
Foreign currency translation adjustments	-	-	(20)	(20)
As at December 31, 2012	$ 91	$ 104	$ 3,932	$ 4,127
Additions	932	-	5	937
Additions into service	(91)	10	81	-
Disposal of North East U.S. assets (note 8)	-	(7)	(747)	(754)
Retirements and other disposals	-	-	(1)	(1)
Transfers to finance lease receivables	(256)	-	-	(256)
Revisions to decommissioning costs	-	-	(38)	(38)
Foreign currency translation adjustments	-	-	51	51
As at December 31, 2013	$ 676	$ 107	$ 3,283	$ 4,066
Accumulated depreciation				
At January 1, 2012	$ -	$ -	$ (313)	$ (313)
Depreciation	-	-	(198)	(198)
Disposal of hydro assets	-	-	15	15
Retirements and other disposals	-	-	43	43
Foreign currency translation adjustments	-	-	4	4
Impairments (note 9)	-	-	(50)	(50)
As at December 31, 2012	$ -	$ -	$ (499)	$ (499)
Depreciation	-	-	(185)	(185)
Disposal of North East U.S. assets (note 8)	-	-	162	162
Retirements and other disposals	-	-	1	1
Foreign currency translation adjustments	-	-	(14)	(14)
Impairments (note 9)	-	-	(6)	(6)
As at December 31, 2013	$ -	$ -	$ (541)	$ (541)
Net book value				
As at January 1, 2012	$ 358	$ 87	$ 3,397	$ 3,842
As at December 31, 2012	$ 91	$ 104	$ 3,433	$ 3,628
As at December 31, 2013	$ 676	$ 107	$ 2,742	$ 3,525

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

18. Property, plant and equipment, continued:

Impairments

Impairments of $6 million on property, plant and equipment were recognized during the year ended December 31, 2013 (year ended December 31, 2012 - $50 million) as described in note 9. No reversals of impairments on property, plant and equipment were recognized during the year ended December 31, 2013 (year ended December 31, 2012 - nil).

Capitalized borrowing costs

Details of borrowing costs capitalized as part of property, plant and equipment are provided in note 5. The average borrowing rate used to capitalize interest during the year was 5.26% (year ended December 31, 2012 – 5.12%) for projects financed using general borrowings. For the years ended December 31, 2013 and December 31, 2012, there were no projects financed using specific borrowings.

Restrictions on assets

Details of charges over land, plant and equipment are provided in note 21.

19. Goodwill:

	2013	2012
Cost		
As at January 1	$ 46	$ 46
Disposal of North East U.S. assets (note 8)	(24)	-
Foreign currency translation adjustments	1	-
As at December 31	$ 23	$ 46
Accumulated impairments		
As at January 1	$ (24)	$ -
Disposal of North East U.S. assets (note 8)	24	-
Impairments (note 9)	-	(24)
As at December 31	$ -	$ (24)
Net book value		
As at January 1	$ 22	$ 46
As at December 31	$ 23	$ 22

The aggregate carrying amounts of goodwill allocated to the Company's CGUs at December 31, 2013 and December 31, 2012 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, 2013 (year ended December 31, 2012 – $24 million related to the North East U.S. CGU).

20. Trade and other payables:

	December 31, 2013	December 31, 2012
Operating accruals	$ 110	$ 115
Trade payables	36	49
Dividends and distributions payable	31	31
Accrued interest	15	15
Income taxes payable	6	-
	$ 198	$ 210

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

21. Loans and borrowings:

	Effective interest rate	December 31, 2013	December 31, 2012
CPLP unsecured senior debt payable to EPCOR			
Due in 2016 at 6.75%	6.16%	$ 130	$ 132
Due in 2018 at 5.80%	5.63%	164	164
Due between 2014 and 2018 at 9.00%	7.41%	47	61
Total CPLP debt payable to EPCOR		341	357
Less: current portion		341	14
		-	343
CPLP debt payable to non-related parties			
Unsecured senior medium-term notes, at 4.60% payable semi-annually, due in 2015	4.71%	300	300
Unsecured senior medium-term notes, at 4.85% payable semi-annually, due in 2019	4.96%	250	250
Unsecured senior medium-term notes, at 5.28% payable semi-annually, due in 2020	5.34%	300	300
Unsecured senior notes (US$230), at 5.21% payable semi-annually, due in 2021	5.29%	245	229
Unsecured senior notes (US$65), at 5.61% payable semi-annually, due in 2026	5.67%	69	64
Non-recourse financing:			
Joffre Cogeneration Project, at 8.59% payable quarterly, due in 2020	8.31%	34	39
Revolving extendible credit facilities, at floating rates, due in 2018		-	103
Revolving extendible credit facilities (US$30), at floating rates, due in 2018		-	30
Total CPLP debt payable to non-related parties		1,198	1,315
Less: current portion		5	5
		1,193	1,310
		1,193	1,653
Less: deferred debt issue costs		12	13
		$ 1,181	$ 1,640

Unsecured senior debt payable to EPCOR

The unsecured senior debt payable to EPCOR matures between 2014 and 2018. As at December 31, 2013, 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. As a result, as at December 31, 2013, all of the unsecured senior debt payable to EPCOR has been classified as current loans and borrowings.

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 $64 million.

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

21. Loans and borrowings, continued:

CPLP revolving extendible credit facilities

Unsecured credit facilities of $700 million, committed to 2018 and uncommitted amounts of $20 million, are available to CPLP. As at December 31, 2013, the Company had no amounts outstanding under these facilities (December 31, 2012 – bankers' acceptances of $93 million, U.S. LIBOR loans of $20 million (US$20 million) and U.S. base rate loans of $10 million (US$10 million)). Additional uncommitted amounts of $5 million are available to the Company and are undrawn at December 31, 2013 (December 31, 2012 – nil).

The Company also has unsecured credit facilities of $500 million available through its CPLP subsidiary. These facilities have a maturity date of July 9, 2018. As at December 31, 2013, no amounts have been drawn on these facilities (December 31, 2012 – bankers' acceptances of $10 million), and letters of credit of $160 million (December 31, 2012 – $208 million) have been issued as described in note 34.

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.

22. Provisions:

	December 31, 2013	December 31, 2012
Decommissioning	$ 120	$ 173
Employee benefits [1]	50	52
Other	5	13
	175	238
Less: current portion	27	24
	$ 148	$ 214

[1] Included in the employee benefits provision is $8 million pertaining to the share-based payment obligations described in note 27, of which $8 million is vested at December 31, 2013 (December 31, 2012 - $7 million total share based payment obligation, $7 million vested).

	Decommissioning	Employee benefits	Other	Total
As at January 1, 2012	$ 157	$ 43	$ 30	$ 230
Additional liabilities incurred	9	32	1	42
Liabilities settled	(1)	(21)	(9)	(31)
Amounts reversed unused	-	(2)	(9)	(11)
Foreign currency translation adjustments	(1)	-	-	(1)
Revisions to decommissioning costs	9	-	-	9
Unwinding of the discount	4	-	-	4
Settlement on disposal of hydro assets	(4)	-	-	(4)
As at December 31, 2012	$ 173	$ 52	$ 13	$ 238
Additional liabilities incurred	16	31	-	47
Liabilities settled	(1)	(29)	-	(30)
Amounts reversed unused	-	(4)	(8)	(12)
Foreign currency translation adjustments	3	-	-	3
Revisions to decommissioning costs	(38)	-	-	(38)
Unwinding of the discount	4	-	-	4
Settlement on disposal of North East U.S. assets (note 8)	(37)	-	-	(37)
As at December 31, 2013	$ 120	$ 50	$ 5	$ 175

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

22. Provisions, continued:

Decommissioning provisions

The Company has recorded decommissioning provisions for its power 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.

At December 31, 2013, the Company estimates the undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $291 million, calculated using an inflation rate of 2%. The expected timing for settlement of the obligations is between 2014 and 2061, which reflects the anticipated useful lives of the different power plants. The majority of the payments to settle the obligations are expected to occur between 2033 and 2061 for the power generation plants and between 2014 and 2020 for the un-reclaimed sections of the Genesee coal mine. Discount rates used to calculate the carrying amount of the obligations range from 1.13% to 4.07%. 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.

Other provisions

The Company holds retail and commercial natural gas customer contracts in Alberta. The future unavoidable costs of meeting the terms of these contracts are expected to exceed the economic benefits to be received under these contracts. As a result, a provision has been recorded on the consolidated statement of financial position to reflect the estimated present value of the loss on these contracts. The expected timing of settlement of these contracts range from 2014 to 2046 and the costs were discounted using risk free rates between 1.06% and 3.23%. The timing and amount of settlement of the obligation is dependent on expectations of renewal of the contracts and expectations over the forward price of natural gas.

23. Share capital:

Authorized shares

	Number of shares authorized
Common shares	unlimited
Preference shares, issuable in series	unlimited
Special voting shares	unlimited
Special limited voting share	one

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

23. Share capital, continued:

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, 2012	58,969,007	$ 1,377	5,000,000	$ 122	38,216,000	$ -
Shares issued	-	-	6,000,000	150	-	-
Share issue costs	-	-	-	(5)	-	-
Deferred taxes on share issue costs	-	-	-	1	-	-
Shares exchanged [1]	9,775,000	230	-	-	(9,775,000)	-
Share purchase options exercised (note 27)	348,349	9	-	-	-	-
Dividend reinvestment plan	863,337	19	-	-	-	-
As at December 31, 2012	69,955,693	$ 1,635	11,000,000	$ 268	28,441,000	$ -
Shares issued	-	-	8,000,000	200	-	-
Share issue costs	-	-	-	(6)	-	-
Deferred taxes on share issue costs	-	-	-	2	-	-
Shares exchanged [1]	9,600,000	202	-	-	(9,600,000)	-
Share purchase options exercised (note 27)	1,757	-	-	-	-	-
Dividend reinvestment plan	1,332,428	27	-	-	-	-
As at December 31, 2013	80,889,878	$ 1,864	19,000,000	$ 464	18,841,000	$ -

[1] EPCOR exchanged 9,600,000 (year ended December 31, 2012 - 9,775,000) of its exchangeable limited partnership units in CPLP on a one-for-one basis for common shares of Capital Power and subsequently entered into an agreement for a secondary offering of 9,600,000 common shares (year ended December 31, 2012 - 9,775,000) of Capital Power at an offering price of $21.00 per common share (year ended December 31, 2012 - $23.55).

There were no transactions in respect of the special voting limited share during the years ended 2013 and 2012.

On April 26, 2013, at Capital Power's annual general meeting of shareholders, the Shareholder Rights Plan (Rights Plan) was ratified. 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.

On March 14, 2013 the Company issued 8 million Cumulative Rate Reset Preference Shares, series 5 (Series 5 Shares) priced at $25.00 per share for gross proceeds of $200 million less issue costs of $6 million. Deferred tax assets of $2 million related to the share issue costs were recorded in the preferred share balance. The preferred shares pay fixed cumulative dividends of $1.125 per share per annum, yielding 4.50% 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, for the initial period ending June 30, 2018. The 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%. The Series 5 Shares are redeemable by Capital Power, at its option, on June 30, 2018 and on June 30 of every fifth year thereafter.

23. Share capital, continued:

Holders of Series 5 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 6 (Series 6 Shares), subject to certain conditions, on June 30, 2018 and on June 30 of every fifth year thereafter. Holders of 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 3.15%, as and when declared by the board of directors of Capital Power.

The Company's 6 million Cumulative Rate Reset Preferred Shares, series 3 (Series 3 Shares) pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% 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, for the initial five-year period ending December 31, 2018. The 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%. The Series 3 Shares are redeemable by Capital Power, at its option, on December 31, 2018 and on December 31 of every fifth year thereafter.

Holders of Series 3 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 4 (Series 4 Shares), subject to certain conditions, on December 31, 2018 and on December 31 of every fifth year thereafter. Holders of Series 4 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 3.23%, as and when declared by the board of directors of Capital Power.

The Company's 5 million Cumulative Rate Reset Preferred Shares, series 1 (Series 1 Shares) pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% 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, for the initial five-year period ending December 31, 2015. The dividend rate will be reset on December 31, 2015 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%. The Series 1 Shares are redeemable by Capital Power, at its option, on December 31, 2015 and on December 31 of every fifth year thereafter.

Holders of Series 1 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 2 (Series 2 Shares), subject to certain conditions, on December 31, 2015 and on December 31 of every fifth year thereafter. Holders of Series 2 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%, as and when declared by the board of directors of Capital Power.

The special voting shares and special limited voting shares were issued to a related party, EPCOR. The special limited voting share entitles holders the right to vote as a class on any matter that would: (i) change the location of Capital Power's head office to a place other than the City of Edmonton in the Province of Alberta; (ii) amend the articles of Capital Power to, or result in a transaction that would, in each case, impact the location of the head office or its meaning as defined in Capital Power's articles; or (iii) amend the rights attaching to the special limited voting share.

The special voting share holders are entitled to nominate and elect four Directors to the Company's Board of Directors, provided that they own not less than 20% of the aggregate number of outstanding Capital Power common shares and CPLP exchangeable LP units (exchangeable for Capital Power common shares). The special voting share holders are entitled to nominate and elect two Directors to the Company's Board of Directors, provided that they own less than 20% but not less than 10% of the aggregate number of outstanding Capital Power common shares and CPLP exchangeable LP units.

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

23. Share capital, continued:

The common and preferred share dividends declared and paid by the Company for the years ended December 31, 2013 and December 31, 2012 are summarized as follows:

	Dividends declared				Dividends paid			
	2013		2012		2013		2012	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 1.2600	$ 92	$ 1.2600	$ 85	$ 1.2600	$ 89	$ 1.2600	$ 81
Preference, Series 1	1.1500	6	1.1500	6	1.1500	6	1.1500	6
Preference, Series 3	1.1776	7	-	-	1.1776	7	-	-
Preference, Series 5	0.8954	7	-	-	0.8954	7	-	-

[1] For the year ended December 31, 2013, dividends paid on common shares consist of $62 million paid in cash and $27 million paid through the Company's dividend reinvestment plan as common shares issued. For the year ended December 31, 2012, dividends paid on common shares consist of $62 million paid in cash and $19 million paid through the Company's dividend reinvestment plan as common shares issued.

24. 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 gain or loss 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 account

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 27.

25. Change in non-cash operating working capital:

	2013	2012
Trade and other receivables	$ 108	$ (105)
Inventories	(10)	(14)
Trade and other payables	(31)	(12)
Provisions	4	(9)
	$ 71	$ (140)

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

26. Related party balances and transactions:

Nature of transactions

Sales to and purchases between the Company and its subsidiaries, or between subsidiaries of the Company, are made at normal market prices. Transactions between the Company and its subsidiaries and transactions between subsidiaries are eliminated on consolidation.

As described in note 32, the Company is party to a number of joint arrangements, primarily for the construction and operation of power generation 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.

Transactions and balances

The following transactions took place during the years ended December 31, 2013 and December 31, 2012 between the Company and its related parties:

	2013	2012
Revenues – energy sales:		
EPCOR and City of Edmonton [1]	$ 27	$ 30
Energy purchases and fuel:		
EPCOR [2]	1	7
Other administrative expenses:		
EPCOR	6	6
Finance expense:		
EPCOR [3]	18	20

[1] Energy sales of $6 million (year ended December 31, 2012 - $9 million) to EPCOR, and $21 million (year ended December 31, 2012 - $21 million) to the City of Edmonton.

[2] Energy purchases and fuel include energy distribution and transmission charges from EPCOR, net of charges flowed through to the City of Edmonton.

[3] Net finance expenses on loans and borrowings owed to EPCOR.

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

26. Related party balances and transactions, continued:

	December 31, 2013	December 31, 2012
Trade and other receivables from related parties:		
EPCOR and City of Edmonton [1]	$ 6	$ 8
Intangible assets:		
EPCOR [2]	4	7
Property, plant and equipment:		
EPCOR [3]	4	5
Trade and other payables to related parties:		
EPCOR [4]	14	17
Current provisions:		
EPCOR [5]	1	-
Non-current provisions:		
EPCOR [5]	2	4
Loans and borrowings from related parties (including current portion):		
EPCOR (note 21)	341	357
Share capital:		
EPCOR (note 23)	-	-

1 Trade and other receivables includes $1 million (December 31, 2012 - $1 million) relating to energy sales to EPCOR, and $5 million (December 31, 2012 - $7 million) related to energy sales to the City of Edmonton.

2 Contributions made to EPCOR for the construction of aerial and underground transmission lines.

3 Interest on loans and borrowings from EPCOR capitalized to property, plant and equipment during the period.

4 Trade and other payables includes interest accrued on the loans and borrowings owed to EPCOR of $6 million (December 31, 2012 - $6 million) and distributions payable to EPCOR of $6 million (December 31, 2012 - $9 million).

5 The provision amounts represent an obligation to EPCOR for future maintenance costs associated with EPCOR's Rossdale plant through 2019.

In addition to the transactions disclosed above, the Company's subsidiary CPLP has recorded total distributions of $33 million to EPCOR for the year ended December 31, 2013 (year ended December 31, 2012 - $39 million). CPLP paid distributions of $36 million to EPCOR in the year ended December 31, 2013 (year ended December 31, 2012 - $42 million).

No provisions for doubtful debts have been established against the trade and other receivables balances for any related party. No bad debt expense was recognized in relation to any transaction with a related party that occurred during the year (2012 - nil).

Details of any commitments between Capital Power and its related parties are disclosed in note 33.

Compensation of key management personnel

	2013	2012
Short-term employee benefits	$ 5	$ 5
Termination benefits	-	1
Share-based payments	2	2
	$ 7	$ 8

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

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

27. 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 2013, the Company granted 740,304 share purchase options with one third vesting on March 14 of each of 2014, 2015 and 2016. The fair values of these options at grant date were $1.28, $1.31 and $1.34 per option for the 2014, 2015 and 2016 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $21.76 per share.

In March 2012, the Company granted 1,449,568 share purchase options with one third vesting on March 26 of each of 2013, 2014 and 2015. The fair values of these options at grant date were $1.47, $1.52 and $1.56 per option for the 2013, 2014 and 2015 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $24.27 per share.

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

	Share purchase options issued in: 2013	2012
Share price at grant date	$ 21.76	$ 24.27
Expected volatility [1]	14.4%	14.0%
Expected option life [2]	4.5 years	4.5 years
Expected dividend yield	5.79%	5.19%
Risk-free interest rate [3]	1.25%	1.26%
Exercise price	$ 21.76	$ 24.27
Expiry date	March 14, 2020	March 26, 2019

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

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

[3] Based on the Government of Canada zero-coupon yield curve. Represents the weighted 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 2013 and 2012:

	2013 Number of options	2013 Weighted average exercise price	2012 Number of options	2012 Weighted average exercise price
Options outstanding, as at January 1	4,385,712	$ 23.75	3,930,334	$ 23.50
Granted	740,304	21.76	1,449,568	24.27
Exercised [4]	(1,757)	22.50	(348,349)	23.04
Forfeited	(913,801)	23.55	(645,841)	23.80
Options outstanding, as at December 31	4,210,458	$ 23.44	4,385,712	$ 23.75
Vested options outstanding, as at December 31	2,558,124	$ 23.48	2,118,107	$ 23.20

[4] The weighted average share price at the date of exercise was $23.23 (2012 - $24.88).

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

27. Share-based payments, continued:

Share purchase options, continued

During the year ended December 31, 2013, the Company recorded compensation expenses of $1 million related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2012 - $2 million).

The weighted average remaining contractual life of the Company's outstanding share purchase options as at December 31, 2013 is 4.2 years (December 31, 2012 – 4.9 years). The exercise prices of share purchase options outstanding as at December 31, 2013 range from $21.76 to $24.90 (December 31, 2012 - $22.50 to $24.90).

Performance share units

Capital Power Corporation grants performance share units (PSUs) to certain employees, which entitles 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. 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 50 percent to 150 percent times the market price of the PSU at the release date.

	2013	2012
PSUs outstanding, as at January 1	356,933	251,490
Granted [1]	202,083	152,048
Exercised [2]	(75,002)	(15,631)
Dividends reinvested	26,825	19,380
Forfeited	(132,403)	(50,354)
PSUs outstanding, as at December 31	378,436	356,933

[1] The fair value of the PSUs at the grant date was $23.16 (2012 - $24.28).

[2] The weighted average share price at the date of exercise was $22.24 (2012 - $22.43).

During the year ended December 31, 2013, the Company recorded compensation expenses of $2 million (year ended December 31, 2012 - $1 million) related to the outstanding PSUs 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 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. During the year ended December 31, 2013, the Company recorded compensation expenses of $1 million (year ended December 31, 2012 – less than $1 million) related to the outstanding DSUs in staff costs and employee benefits expense.

28. Financial instruments:

Fair values

Details of the fair values of the Company's derivative instruments are described in note 13.

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.

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

28. Financial instruments, continued:

Fair values, continued

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

		December 31, 2013		December 31, 2012	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets – non-current (note 15)					
Loans and receivables	Level 2	$ 34	$ 34	$ 55	$ 55
Finance lease receivable (note 14)					
Loans and receivables	Level 2	711	647	461	374
Loans and borrowings (note 21)					
Other financial liabilities (includes current portion)	Level 2	1,527	1,561	1,659	1,736

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, 2013 and December 31, 2012.

Loans and borrowings

The fair value of the Company's loans and borrowings is based on determining a current yield for the Company's loans and borrowings as at December 31, 2013 and December 31, 2012. 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.

Fair value hierarchy

Fair value represents the Company's estimate of the price at which a financial instrument could be exchanged between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated statement of financial position are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The following levels were established for each input:

- Level 1: Fair value is based on quoted prices (unadjusted) in active markets for identical instruments. Financial instruments 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 financial instruments 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. Financial instruments classified in Level 2 include commodity and foreign exchange derivatives whose values are determined based on broker quotes, observable trading activity for similar, but not identical instruments, and prices published on information platforms and exchanges.

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

28. Financial instruments, continued:

Fair value hierarchy, continued

- 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 financial instruments 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. Financial instruments classified in Level 3 include long-dated commodity derivatives, commodity contracts involving non-standard features, transmission and commodity based options, and credit derivatives whose values are in part determined based on historical data such as plant operation costs, credit default probabilities, transmission congestion, demand profiles, volatilities and correlations between products derived from historical prices.

The fair value measurement of a financial instrument 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.

The following tables present the Company's financial instruments measured at fair value on a recurring basis in the consolidated statement of financial position, classified using the fair value hierarchy described above:

	December 31, 2013			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets				
Commodity derivatives	$ -	$ 66	$ -	$ 66
Foreign exchange derivatives	-	1	-	1
	$ -	$ 67	$ -	$ 67
Derivative financial instruments liabilities				
Commodity derivatives	-	(39)	-	(39)
Foreign exchange derivatives	-	(1)	-	(1)
Interest rate derivatives	-	(1)	-	(1)
	$ -	$ (41)	$ -	$ (41)

	December 31, 2012			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets				
Commodity derivatives	$ 25	$ 52	$ -	$ 77
Derivative financial instruments liabilities				
Commodity derivatives	(30)	(18)	(16)	(64)

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, 2013 and 2012.

Valuation techniques used in determination of fair values within Level 2

The fair values of the Company's commodity derivatives included within Level 2 are determined by applying the Spread Option Pricing Model. The valuation model is based on underlying forward prices, heat rates based on contract details, strike price of the options based on contract details, risk-free interest rates estimated based on market interest rate swap quotes as well as time to expiration calculated based on parameters within the contracts.

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

28. Financial instruments, continued:

Fair value hierarchy, continued

Valuation techniques used in determination of fair values within Level 2, continued

The fair values of the Company's interest rate derivatives included within Level 2 are determined by discounting future cash flows. The inputs used in these calculations include forward interest rate curves and volatility levels and are based on observable market data.

The fair values of the Company's foreign exchange derivatives included within Level 2 are determined by discounting future cash flows. The inputs used in these calculations include forward foreign exchange curves, Canadian and U.S. dollar swap rates and corporate credit curves and are based on observable market data.

Continuity of Level 3 balances

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

	2013	2012
As at January 1 [1]	$ (16)	$ (1)
Unrealized and realized gains (losses) included in net income [2]	26	(23)
Settlements	(10)	8
As at December 31	$ -	$ (16)
Total unrealized gains (losses) for the year included in net income	$ 16	$ (15)

[1] The fair value of derivative instruments is presented on a net basis.

[2] Gains and losses are recorded in revenues or energy purchases and fuel, as appropriate.

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

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.

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

28. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

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, 2013

				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	$ 139	$ (9)	$ 130	$ (21)	$ (2)	$ 107

[1] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $31 million, non-current derivative instruments assets of $35 million and trade and other receivables of $64 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.

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

As at December 31, 2013

				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 [4]	Net amount
Commodity trading liabilities	$ 86	$ (9)	$ 77	$ (28)	$ (4)	$ 45

[3] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $29 million, non-current derivative instruments liabilities of $10 million and trade and other payables of $38 million.

[4] Collateral pledged against the net financial liabilities disclosed above consists of $3 million in cash collateral and $1 million in letters of credit issued.

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

28. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

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

As at December 31, 2012

				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	$ 235	$ (38)	$ 197	$ (42)	$ (5)	$ 150

[1] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $47 million, non-current derivative instruments assets of $30 million and trade and other receivables of $120 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.

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

As at December 31, 2012

				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 [4]	Net amount
Commodity trading liabilities	$ 166	$ (38)	$ 128	$ (52)	$ (24)	$ 52

[3] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $52, non-current derivative instruments liabilities of $12 and trade and other payables of $64.

[4] Collateral pledged against the net financial liabilities disclosed above consists of $6 million in cash collateral and $18 million in letters of credit issued.

29. 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 a senior management group.

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 and 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 variously:

29. 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, 2013, that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 13.

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.

29. Risk management, continued:

Market risk, continued

Commodity price risk, continued

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, 2013, there is a 99% probability that unfavourable daily market variations would not reduce the fair value of the trading portfolio by more than $1 million.

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, 2013, the Company held foreign exchange derivatives as disclosed in note 13.

As at December 31, 2013, 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 $3 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, 2013, the proportion of fixed rate loans and borrowings was approximately 100% of total loans and borrowings outstanding (December 31, 2012 - 92%). The Company may also use derivative instruments to manage interest rate risk. At December 31, 2013, the Company held interest rate derivatives as disclosed in note 13 which have effectively reduced the proportion of fixed rate loans and borrowing disclosed above to 94%.

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

29. Risk management, continued:

Market risk, continued

Interest rate risk, continued

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, 2013, a 100 basis point decrease or increase to interest rates would decrease or increase full year net income attributable to common shareholders by $4 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.

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:

	December 31, 2013	December 31, 2012
Cash and cash equivalents	$ 100	$ 53
Trade and other receivables [1]	208	354
Derivative financial instruments assets [1]	67	77
Loans and other long-term receivables	34	55
Finance lease receivables	711	461
	$ 1,120	$ 1,000

[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 $130 million (December 31, 2012 - $240 million) for generation counterparties and $145 million (December 31, 2012 - $191 million) for wholesale counterparties at December 31, 2013.

This table does not take into account collateral held. As at December 31, 2013, the Company held cash deposits of nil (December 31, 2012 - $6 million) as security for certain counterparty trade and other receivables and derivative contracts. The Company is not permitted to sell or re-pledge this collateral in the absence of default of the collateral providers. As at December 31, 2013, the Company also held other forms of credit enhancement in the forms of letters of credit of $4 million (December 31, 2012 - $53 million), property registrations valued at $19 million (December 31, 2012 - $34 million) and parental guarantees of $1,278 million (December 31, 2012 - $957 million) related to the financial assets noted above. As at December 31, 2013 and December 31, 2012, 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.

29. 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, 2013 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)

29. 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, 2013 was:

	Gross trade and other receivables	Allowance for doubtful accounts	Net trade and other receivables
Current [1]	$ 207	$ -	$ 207
Outstanding 30 - 60 days	-	-	-
Outstanding 60 - 90 days	-	-	-
Outstanding greater than 90 days	1	-	1
	$ 208	$ -	$ 208

[1] 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:

	2013	2012
As at January 1	$ 2	$ 1
Amounts reversed unused	(2)	(1)
New allowance	-	2
As at December 31	$ -	$ 2

Bad debt expenses (net of recoveries) of nil and $1 million were recognized in the years ended December 31, 2013 and 2012 respectively.

As at December 31, 2013, the Company held no customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers (December 31, 2012 - $6 million).

As at December 31, 2013 and December 31, 2012, 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)

29. 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), assigned by Standard & Poor's (S&P) and a preferred share rating of P-3 and Pfd-3(low) assigned by S&P and DBRS Limited (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, 2013, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $1,065 million (December 31, 2012 - $884 million), of which $1,040 million is committed for at least 4 years (December 31, 2012 - $859 million committed for at least four years).

In addition to the facilities noted above, the Company, through its own facilities and those of its subsidiary, CPLP, has shelf prospectuses under which it may raise funds in the form of debt or equity. As at December 31, 2013, Capital Power had a Canadian shelf prospectus, which expires in March 2014, under which it may raise up to $2 billion collectively in common shares of the Company and subscription receipts exchangeable for common shares and/or other securities of the Company. As at December 31, 2013, the amounts available on the shelf prospectus are $1,218 million. As at December 31, 2013, the Company's subsidiary, CPLP, had a Canadian shelf prospectus, which expires in July 2014, under which it may raise up to $1 billion in medium-term notes. As at December 31, 2013, CPLP has not drawn on the shelf prospectus (December 31, 2012 – nil).

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, 2013:

	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	$ 346	$ 306	$ 5	$ 5	$ 5	$ 872	$ 1,539
Interest payments on loans and borrowings	83	61	47	46	45	99	381
Trade and other payables [1]	183	-	-	-	-	-	183
Other current liabilities and deferred revenue	5	-	-	-	-	-	5
Derivative financial liabilities:							
Net commodity contracts for differences	26	2	3	1	-	-	32
Foreign exchange derivatives	1	-	-	-	-	-	1
Interest rate derivatives	1	-	-	-	-	-	1
Total	$ 645	$ 369	$ 55	$ 52	$ 50	$ 971	$ 2,142

[1] Excluding accrued interest on loans and borrowings of $15 million.

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

30. 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:

	2013	2012
Loans and borrowings (note 21)	$ 1,527	$ 1,659
Cash and cash equivalents (note 10)	(100)	(53)
Net debt	1,427	1,606
Non-controlling interests (note 31)	587	829
Share capital (note 23)	2,328	1,903
Retained earnings and other reserves	89	20
Total equity	3,004	2,752
	$ 4,431	$ 4,358

The Company, through its subsidiary 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, 2013, the Company and its subsidiaries complied with all externally imposed capital restrictions.

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)

31. 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, 2013:

	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	81%	19%	Power generation
Genesee Coal Mine Assets (Coal Mine) [2]	Canada	50%	50%	Coal production for use in power generation

[1] EPCOR owns 18.841 million (December 31, 2012 – 28.441 million) exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) which represents approximately 19% of CPLP (December 31, 2012 – 29%). Each exchangeable limited partnership unit is accompanied by a special voting share in the capital of Capital Power which entitles the holder to a vote at Capital Power shareholder meetings, subject to the restriction that such special voting shares must at all times represent not more than 49% of the votes attached to all Capital Power common shares and special voting shares, taken together. The special voting shares also entitle EPCOR, voting separately as a class, to nominate and elect a maximum of two (December 31, 2012 – four) directors of Capital Power of the current eleven (December 31, 2012 – twelve) directors on Capital Power's board of directors. Although EPCOR, through its ownership of the special voting shares described above, is the largest single shareholder, its representation on the board of directors does not represent a controlling vote. Capital Power is the general partner of, and holds an 81% partnership interest in, CPLP (December 31, 2012 – 71%). Through this interest, Capital Power has rights to variable returns from its involvement with CPLP and has the ability to affect those returns through its power over CPLP. As a result Capital Power has control over CPLP and, on that basis, the operations of CPLP are consolidated by Capital Power for financial statement purposes.

[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 upon 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 upon 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 30.

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

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

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

	December 31, 2013		December 31, 2012	
Consolidated statements of financial position	CPLP	Coal Mine	CPLP	Coal Mine
Current assets	$ 429	$ -	$ 525	$ -
Non-current assets	4,808	156	4,638	165
Current liabilities	(687)	-	(363)	-
Non-current liabilities	(1,856)	-	(2,183)	-
Non-controlling interests - Genesee Coal Mine	(78)	-	(82)	-
Non-controlling interests - other	(22)	-	(12)	-
Net assets	$ 2,594	$ 156	$ 2,523	$ 165

	2013		2012	
Consolidated statements of income	CPLP	Coal Mine	CPLP	Coal Mine
Revenues	$ 1,383	$ -	$ 1,291	$ -
Net income attributable to partners	240	(24)	120	(24)
Other comprehensive income attributable to partners	(47)	-	42	-
Total comprehensive income attributable to partners	$ 193	$ (24)	$ 162	$ (24)

	2013		2012	
Consolidated statements of cash flows	CPLP	Coal Mine	CPLP	Coal Mine
Net cash flows from operating activities	$ 507	$ -	$ 241	$ -
Net cash flows used in investing activities	(341)	(15)	(448)	(14)
Net cash flows (used in) from financing activities	(118)	15	188	14
Foreign exchange losses on cash held in a foreign currency	(1)	-	(1)	-
Net increase (decrease) in cash and cash equivalents	47	-	(20)	-
Cash and cash equivalents at beginning of year	53	-	73	-
Cash and cash equivalents at end of year	$ 100	$ -	$ 53	$ -

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

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

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

	December 31, 2013	December 31, 2012
Non-controlling interest in CPLP, beginning of year	$ 747	$ 985
Net income attributable to non-controlling interest	65	40
Other comprehensive income attributable to non-controlling interest	(12)	14
Distributions to non-controlling interest (note 26)	(33)	(39)
Exchange of CPLP units for Capital Power shares (note 23)	(258)	(253)
Non-controlling interest in CPLP, end of year	509	747
Non-controlling interest in Genesee Coal Mine, beginning of year	82	87
Net income attributable to non-controlling interest	(12)	(12)
Net additional investment by non-controlling interest	8	7
Non-controlling interest in Genesee Coal Mine, end of year	78	82
	$ 587	$ 829

32. Interests in joint arrangements:

Joint operations

The Company holds interests in the following joint operations as at December 31, 2013:

	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[4]	Canada	50%

[1] G3 is a 516-megawatt (MW) power plant and is a 50/50 joint arrangement between Capital Power and a third party, with Capital Power acting as the manager and operator. Capital Power operates the merchant plant, and both parties independently dispatch and market their share of the electrical output through the Alberta Power Pool.

[2] K3 is a 495MW (450-MW net) 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.

[3] Joffre Cogeneration Project is a 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] The Shepard Energy Centre (Shepard) is an 800MW gas-fired generating facility and is a 50/50 joint arrangement between Capital Power and a third party with the third party responsible for operations. Shepard is currently under construction as described in note 33(b).

There are no significant restrictions pertaining to the joint operations described above, other than those described in note 21 pertaining to the charge on the Joffre Cogeneration project assets.

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

32. Interests in joint arrangements, continued:

Joint ventures

The Company holds an interest in the following joint venture as at December 31, 2013:

	Place of business	Measurement Method
K2 Wind Power Project[1]	Canada	Equity method

[1] The K2 Wind Power Project (K2 Wind) is a 270MW wind power project currently under development and construction. Capital Power has entered into agreements with two third parties for the development, construction and operation of K2 Wind. Capital Power and each of the third parties will hold an equal 33.33% ownership interest in K2 Wind. 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.

The summarized financial information of K2 Wind is as follows:

Statements of Financial Position	December 31, 2013	December 31, 2012
Cash and cash equivalents	$ 3	$ 2
Other current assets	19	-
Non-current assets [2]	52	31
Current financial liabilities	(5)	(1)
Other current liabilities	(25)	-
Other non-current liabilities	-	(23)
Net assets	$ 44	$ 9

[2] K2 Wind has restricted cash of $5 million included in non-current assets above (December 31, 2012 - $5 million) which represents security for a standby line of credit with a third party.

Statements of Income	2013	2012
Revenues	$ -	$ -
Depreciation and amortization	-	-
Finance expense	-	-
Income tax expense	-	-
Net loss and total comprehensive loss	$ (2)	$ (1)

The Company's recorded equity investment in K2 Wind of $15 million (December 31, 2012 - $3 million) reconciles to the Company's 33.33% share of the net assets of K2 Wind.

33. 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 2014 is $93 million. It is expected that the annual payments over the remaining term of the Sundance PPA, as described in note 17, will range from $93 million to $118 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 and scheduled outages.

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

33. Commitments and contingencies, continued:

(b) The Company is party to a series of agreements with a third party to purchase a 50% interest in the 800 MW Shepard Energy Centre in southern Alberta. The Company expects to invest approximately $821 million, including capitalized borrowing costs, into Shepard, which is expected to commence commercial operations in early 2015. The two parties will build, own and operate Shepard under a joint arrangement. In conjunction with the joint arrangement, the parties will be subject to various commercial agreements, including a 20 year tolling agreement. Under the tolling agreement, 75% of Capital Power's share of the output will be sold at a fixed capacity charge to the other party to the joint arrangement for the years 2015 through 2017 decreasing to 50% of the output for the years 2018 to 2035. As at December 31, 2013, the estimated total remaining capital cost to be incurred is $137 million.

(c) The K2 wind joint venture, in which the Company holds a 33% interest as described in note 32, will develop, construct and operate the 270 MW K2 Wind Ontario (K2) power project in southern Ontario. K2 has an expected capital cost of $874 million, which will be shared by each of the three venturers equally through their equity interests in the joint venture. As at December 31, 2013 the estimated total remaining capital cost for the Company's share of the project is $275 million of which a portion will be financed within the joint venture. Energy generated by K2 will be sold under a PPA to a third party. K2 is expected to commence commercial operations in 2015. Included in the estimated remaining capital cost to be incurred is the Company's $5 million share of a third party contract termination payment to a third party outside of this joint venture.

(d) The Company has entered into 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 [1]
Within one year	$ 79	$ 13	$ 26	$ 8
Between one and five years	62	48	34	30
After five years	71	57	-	78
	$ 212	$ 118	$ 60	$ 116

[1] Operating lease amounts include $5 million per year through 2031 for head office lease costs payable to EPCOR.

(e) Capital Power is participating in a proceeding underway before the Alberta Utilities Commission (AUC) regarding factors that form the basis for certain transmission charges paid by Alberta generators including Capital Power. On April 16, 2012, the AUC issued its decision that the factors utilized from 2006 to the present time were non-compliant with the applicable legislation and regulations. Capital Power and other Alberta generators subsequently submitted applications to review and vary that decision. On April 23, 2013, the AUC issued its subsequent decision that there is substantial doubt regarding the correctness of the previous decision. The AUC has scheduled a review proceeding that will determine whether the initial decision should be varied and, if so, how. This includes the potential application of alternative factors on a prospective or retrospective basis. Capital Power may incur additional payments for transmission charges on a retrospective and go-forward basis but a provision has not been recorded in the Company's financial statements since the outcome of the proceeding is not known. The AUC review proceeding commenced in October 2013 and it is anticipated that the AUC's decision will be issued no sooner than the first half of 2014.

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

33. Commitments and contingencies, continued:

(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.

34. Guarantees:

The Company, through its subsidiary CPLP, has issued letters of credit of $160 million (December 31, 2012 - $208 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

35. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation plants within Canada (Alberta, British Columbia and Ontario) and in the U.S. (North Carolina), as this is how management assesses performance and determines resource allocations. The assets disposed of during the year ended December 31, 2013, as described in note 8, operated within the U.S. (Connecticut, Maine and Rhode Island). Since the disposal of those assets did not represent the disposal of a separate major line of business or geographic area, the disposal of those assets is not considered a discontinued operation.

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

	Year ended December 31, 2013				Year ended December 31, 2012			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 1,048	$ 345	$ -	$1,393	$ 947	$ 349	$ -	$1,296
Revenues - inter-area	43	(2)	(41)	-	18	8	(26)	-
Total revenues	$ 1,091	$ 343	$ (41)	$1,393	$ 965	$ 357	$ (26)	$1,296

	As at December 31, 2013			As at December 31, 2012		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,441	$ 84	$ 3,525	$ 2,947	$ 681	$ 3,628
Intangible assets	309	1	310	298	8	306
Goodwill	-	23	23	-	22	22
Other assets	27	-	27	21	-	21
	$ 3,777	$ 108	$ 3,885	$ 3,266	$ 711	$ 3,977

36. Subsequent event:

In July 2012, the Sundance plant owner made a force majeure claim for $39 million with respect to the 2011 third quarter outage of Unit 6 due to a transformer failure. The Company has a 52% interest in the Sundance acquired PPA for Units 5 and 6 and thus was contractually responsible for paying its share of the claimed amount in advance of final determination of whether or not a force majeure situation, as specified in the PPA, occurred. Accordingly, Capital Power paid its share of the claimed amount and, based on the Company's view that the claim would not meet the PPA specified force majeure tests, recorded it as an amount receivable until final resolution of the claim. The claim was under arbitration but the Company entered into settlement negotiations with the plant owner. At the time of payment in 2012, the Company recorded its $20 million payment as an amount receivable included in non-current other financial assets. Based on the analysis performed in preparation for the arbitration and potential settlement, the Company reduced the amount receivable to $10 million in the fourth quarter of 2013 and reclassified the receivable from non-current to current. In February 2014, the Company reached a settlement with the plant owner and will receive payments consistent with the revised receivable amount. The settlement also resolves a 2012 dispute relating to index 9 of the PPA with immaterial consequences to the Company.

37. Comparative figures:

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