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Capital Power reports third quarter results

Strong plant availability and higher Alberta power prices lead to excellent results from the Alberta contracted plants

EDMONTON, Alberta – Capital Power Corporation ("Capital Power", or the "Company") (TSX: CPX) today released its financial results for the third quarter and nine months ended September 30, 2013. The Company also reiterated that it expects to exceed its 2013 financial guidance for normalized earnings per share and cash flow per share.

Normalized earnings attributable to common shareholders in the third quarter of 2013 were $51 million, or $0.72 per share, compared with $38 million, or $0.55 per share, in the comparable period of 2012.

Funds from operations were $122 million in the third quarter of 2013, down 5 per cent from $128 million in the third quarter of 2012. Cash flow per share for the quarter was $1.23 compared with $1.31 for the same quarter in the previous year.

Net income attributable to shareholders in the third quarter of 2013 was $44 million, or $0.55 per share, compared with net income attributable to shareholders of $39 million, or $0.55 per share, in the comparable period of 2012.

For the nine months ended September 30, 2013, normalized earnings attributable to common shareholders were $95 million, or $1.35 per share, compared with $70 million, or $1.06 per share, in the first nine months of 2012. Funds from operations totaled $310 million compared with $298 million in the comparable nine-month period last year.

"Third quarter results exceeded management's expectations," said Brian Vaasjo, President and CEO of Capital Power. "Normalized earnings of $0.72 per share increased significantly from $0.55 per share a year ago. Alberta power prices averaged $84 per megawatt hour (MWh) in the third quarter compared to $78 per MWh in the third quarter of 2012. The combination of the higher average Alberta power prices and nearly 100% availability from our Alberta contracted plants resulted in higher availability incentive revenues, which in turn led to a strong adjusted EBITDA contribution of $55 million for this segment, up 45% compared to the same period a year ago."

"With Alberta power prices averaging $90 per MWh in the first nine months of the year compared to $58 per MWh that was used to develop our 2013 financial targets, Capital Power remains on track to exceed our 2013 financial targets," continued Mr. Vaasjo.

"At the end of August, we announced a refocusing of our merchant power business on Alberta, which included a number of direct and indirect cost saving initiatives that will reduce annual expenses by approximately $25 million to $30 million starting in 2014. This refinement of Capital Power's strategy to create a leaner, more focused business with less risk is expected to provide our shareholders with a stable and growing contracted cash flow base with upside exposure to the attractive Alberta power market," said Mr. Vaasjo.

Operational and Financial Highlights [1] (unaudited)	**Three months ended September 30**		**Nine months ended September 30**	
(millions of dollars except per share and operational amounts)	**2013**	**2012**	**2013**	**2012**
Electricity generation (excluding acquired Sundance PPA) (GWh)	4,317	4,575	12,205	12,296
Generation plant availability (excluding acquired Sundance PPA) (%)	97%	97%	93%	92%
Revenues and other income	$ 380	$ 394	$ 1,066	$ 1,031
Adjusted EBITDA [2]	$ 151	$ 151	$ 390	$ 368
Net income attributable to shareholders	$ 44	$ 39	$ 98	$ 47
Basic earnings per share	$ 0.55	$ 0.55	$ 1.19	$ 0.65
Diluted earnings per share	$ 0.51	$ 0.55	$ 1.14	$ 0.63
Dividends declared per common share	$ 0.3150	$ 0.3150	$ 0.9450	$ 0.9450
Normalized earnings attributable to common shareholders [2]	$ 51	$ 38	$ 95	$ 70
Normalized earnings per share [2]	$ 0.72	$ 0.55	$ 1.35	$ 1.06
Funds from operations [2]	$ 122	$ 128	$ 310	$ 298
Cash flow per share [2]	$ 1.23	$ 1.31	$ 3.13	$ 3.05
Discretionary cash flow [2]	$ 76	$ 79	$ 134	$ 120
Capital expenditures	$ 422	$ 150	$ 884	$ 433

1 The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the unaudited Condensed Interim Consolidated Financial Statements for the nine months ended September 30, 2013.

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

Significant Events

Purchase of interest in Shepard Energy Centre

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 $860 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, under the new accounting standard for joint arrangements, as a joint operation.

Agreement to sell North East U.S. assets and refocusing of business

On August 28, 2013, Capital Power announced that it has entered into an agreement with Emera Inc. to sell its three North East U.S. combined cycle, natural gas-fired power generation facilities for US$541 million. This transaction is expected to close in the fourth quarter of 2013, subject to regulatory approvals and other customary closing conditions. The timing of the closing may be affected by the U.S. Federal government shutdown and debt ceiling issues which could impact the Federal Energy Regulatory Commission's regulatory approval processing time. The Company has recorded a pre-tax impairment loss of $6 million in the third quarter of 2013. When the sale is finalized, Capital Power expects to record a gain on disposal that includes the related accumulated foreign currency translation gains of $51 million that, as at September 30, 2013, were recorded in other reserves as accumulated other comprehensive income.

The Company has incurred pre-tax restructuring costs of approximately $12 million, cumulatively in the second and third quarters of 2013, as a result of its decision to exit the North East U.S. market and to refocus its merchant power business in Alberta. Future expected impacts include efficiencies in operations and maintenance spending while approximately 160 employee positions will have been eliminated by the end of 2013 resulting in approximately 700 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 costs savings consist primarily of employee compensation including benefits less margins from the discontinued trading operations.

$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.) has assigned a rating of P-3 and DBRS Limited has assigned a rating of Pfd-3 (low) for these Series 5 Shares.

Subsequent Event

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. The underwriters for the sale of common shares were granted an option to purchase up to an additional 1,440,000 common shares at the issue price to cover over-allotments, if any. The over-allotment option is exercisable, in whole or in part, by the underwriters at any time up to 30 days after the closing of the offering. Capital Power will not receive any of the proceeds from EPCOR's sale of common shares. The October 10, 2013 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%. If the over-allotment option is fully exercised, EPCOR's ownership interest will be further reduced to 18%. 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 has 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 September 30, 2013 was approximately $342 million. Also, EPCOR may only elect two of Capital Power's directors compared to four previously.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on October 28, 2013 at 11:00 AM (ET) to discuss third 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 1053151# followed by participant code 21543#. The replay will be available until midnight on January 28, 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, (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 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 net income, funds from operations to net cash flows from operating activities and normalized earnings attributable to common shareholders to net income attributable to common shareholders are contained in the Company's Management's Discussion and Analysis dated October 25, 2013 for the nine months ended September 30, 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: (i) expectations regarding future earnings, (ii) expectations regarding future cash flows, and (iii) expectations regarding the sale of the North East U.S. assets and the refocusing of the Company's merchant power business.

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 commodity prices in markets in which the Company operates 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 December 31, 2012 annual Management's Discussion and Analysis for further discussion of these and other risks.

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Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated October 25, 2013, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the nine months ended September 30, 2013, the audited consolidated financial statements and MD&A of Capital Power Corporation for the year ended December 31, 2012, the annual information form of Capital Power Corporation dated March 14, 2013 and the cautionary statements regarding forward-looking information which begin on page 2. 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 nine months ended September 30, 2013 and the nine months ended September 30, 2012 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods which were prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors has approved this MD&A as of October 25, 2013.

Contents

The Business and Corporate Structure

Capital Power is a growth-oriented North American independent power producer headquartered in Edmonton, Alberta. The Company develops, acquires, operates and optimizes power generation from a variety of energy sources. Capital Power owns more than 3,600 megawatts (MW) of power generation capacity at 16 facilities across North America and has rights to 371 MW through its interest in the acquired Sundance power purchase arrangement (acquired Sundance PPA). An additional 595 MW of owned generation capacity is under construction or in advanced development 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 September 30, 2013, the Company directly and indirectly held approximately 21.750 million general partnership units and 46.699 million common limited partnership units of CPLP which represented approximately 71% of CPLP's total partnership units. Also, as at September 30, 2013, EPCOR (in this MD&A, EPCOR refers to EPCOR Utilities Inc. collectively with its subsidiaries) held 28.441 million exchangeable common limited partnership units of CPLP which represented approximately 29% of CPLP. (See Subsequent Event.) CPLP's exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis. The general partner of CPLP is wholly-owned by Capital Power Corporation and EPCOR's representation on the Board of Directors does not represent a controlling vote. Accordingly, Capital Power Corporation controls CPLP and the operations of CPLP have been consolidated for financial statement purposes.

Corporate Strategy

In August 2013, Capital Power announced the agreement to sell its North East U.S. assets and the refocusing of its merchant power business on Alberta. The Company will continue to pursue growth in contracted power generation across North America. (See Significant Events.) During the nine months ended September 30, 2013, the Company purchased a 50% ownership interest in Shepard Energy Centre in two tranches (see Significant Events), continued construction and development of the Port Dover & Nanticoke and K2 wind projects, and continued the process of planning for the development of Genesee 4 & 5 (formerly Capital Power Energy Centre). The Company also implemented an Enterprise Resource Planning system to support its strategic objectives.

Forward-looking Information

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

Material forward-looking information in this MD&A includes information with respect to: (i) expectations related to future earnings and funds from operations, (ii) expectations regarding the future pricing of electricity and market fundamentals in existing and target markets, (iii) expectations regarding fuel supply and pricing, (iv) expectations related to the Company's future cash requirements including interest and principal repayments, capital expenditures and dividends, (v) expectations for the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings, (vi) expectations regarding future growth and emerging opportunities in the Company's target markets including the focus on certain technologies, (vii) expectations regarding the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions, (viii) expectations regarding plant availability, (ix) expectations regarding the sale of the North East U.S. assets and the refocusing of the Company's merchant power business, and (x) 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 in the Company's December 31, 2012 annual MD&A for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the 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.

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 core measures. The corporate measures are company-wide and include funds from operations and safety. The core measures are specific to certain groups of the Company and 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 full year target	Actual results for the nine months ended September 30, 2013
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	$68 million
Maintenance and operating expenses	$225 million to $245 million	$143 million

[1] All plants excluding acquired Sundance PPA.

The Company's plant availability for the nine months ended September 30, 2013 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. There are no further major outages scheduled for the last quarter of 2013 so the plant availability average for the full year is expected to meet the 2013 full year target.

Capital expenditures for maintenance of the plants, Genesee mine extension and other for the nine months ended September 30, 2013 were consistent with the 2013 full year target and it is expected that actual capital expenditures in the last quarter of 2013 will result in actual full year amounts being close to the target.

The maintenance and operating expenses target includes other raw materials and operating charges, staff costs and employee benefits expense and other administrative expenses for the Company's plants. The actual results for the nine months ended September 30, 2013 indicate that 2013 full year actual results will be less than the target range.

Financial stability and strength

Performance measure	2013 full year target	Actual results for the nine months ended September 30, 2013
Normalized earnings per share [1]	$1.20 to $1.40	$1.35
Funds from operations [1]	$385 million to $415 million	$310 million
Cash flow per share [1]	$3.80 to $4.20	$3.13

[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 the nine months ended September 30, 2013 compared with the 2013 financial targets were impacted by higher than expected Alberta power prices and unplanned plant maintenance outages. These actual results for the first three quarters of 2013 support Capital Power's expectation that full year financial performance measures will exceed their target ranges (see Outlook).

Enhancing shareholders' value

Performance measure	2013 full year target	Status at September 30, 2013
Port Dover & Nanticoke wind project	Continue on budget of $340 million and on time with commercial operation date in the fourth quarter of 2013	On track with target
K2 wind project	Environmental approvals received in 2013	On track with target
Shepard Energy Centre	Continue on budget of $860 million	On track with target

These growth projects are all on track with target. Full notice to proceed on the Port Dover & Nanticoke wind project was received in April 2013. The K2 wind project received its Renewable Energy Approval from the Ontario Ministry of the Environment in July 2013.

Outlook

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

The Company's financial targets for 2013 are based on an average Alberta power price of $58 per megawatt hour (MWh). Normalized earnings per share, as reflected in the 2013 targets and based on forecast power prices and spark spreads, were expected to be in the range of $1.20 to $1.40 for the full year. The Company's forecast of power prices in Alberta has increased as a result of the tightening of supply. Based on the actual results for the first three quarters of 2013 and the Company's forecast power prices and spark spreads for the last quarter of 2013, Capital Power expects that 2013 full year normalized earnings per share will exceed the target range.

As at September 30, 2013, the forecast hedged positions and contracted prices from the baseload plants and acquired Sundance PPA in the Alberta commercial portfolio were:

Alberta commercial portfolio positions and power prices	October to December 2013	Full year 2014	Full year 2015
Percentage sold forward	81%	92%	77%
Contracted price [1]	Mid-$60 per MWh	High-$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 2013 results will include a full year of operations from the Quality Wind and Halkirk wind facilities which commenced operations in the fourth quarter of 2012.

The plant availability target for 2013 of 93% reflects scheduled maintenance outages at Genesee 1 and at Keephills 3 and excludes the acquired Sundance PPA. The outages at both Genesee 1 and Keephills 3 were completed in the second quarter of 2013.

The 2013 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, dispositions or development activities, or potential impacts from unplanned plant outages including outages at facilities of other market participants, and the related impacts on market power prices. Based on the expected portfolio position and assuming all other potential variables are held constant, an increase (decrease) in Alberta power prices of $1.00 per MWh would increase (decrease) estimated adjusted EBITDA by approximately $2 million.

The Company's estimated 2013 capital expenditures in the following table only include expenditures for previously identified growth projects and exclude the cost of potential new development projects:

(unaudited, $millions) **Capital expenditures – growth**	**Target completion date**	**Year ended December 31, 2013 estimated**
Halkirk and Quality Wind post-commercial operations date completion	Completed 4th quarter 2012	7
Port Dover & Nanticoke	4th quarter 2013	272
K2 [1]	2015	30
Shepard Energy Centre	2015	660
		969

[1] Capital Power entered into a partnership agreement to develop K2 which is expected to be in operation by 2015. The 2013 capital expenditures estimated for the K2 project consist primarily of the Company's estimated contribution towards the partnership's equity.

The most recent estimate for 2013 capital expenditures for growth projects increased to $969 million from $635 million as was disclosed in the Company's December 31, 2012 MD&A. This increase is attributed primarily to acceleration of the Shepard second tranche payment to the third quarter of 2013 from the original planned timing of the first quarter of 2014. The total project estimated costs up to completion date remain unchanged. See Significant Events.

(unaudited, $millions) **Capital expenditures – sustaining**	**Year ended December 31, 2013 estimated**
Plant maintenance	75
Genesee mine maintenance [1]	7
Other	11
	93
Genesee mine lands	9
	102

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

Based on the actual expenditures for the nine months ended September 30, 2013 and the current forecast for the last quarter of 2013, estimated 2013 sustaining capital expenditures remain at $102 million which is unchanged from the estimate included in the Company's December 31, 2012 MD&A.

As a result of revised Canadian Federal government coal regulations, the useful life of existing coal plants was effectively set at up to 50 years. Effective January 1, 2013, Capital Power has revised the useful lives of its coal plants in accordance with these regulations resulting in lower depreciation expense.

On April 2, 2013, a single-turbine fire occurred at Capital Power's Kingsbridge 1 wind-energy facility located in Ontario. There were no injuries or damages to public property and the fire was contained to a single turbine. Capital Power and the turbine manufacturer continue to investigate the root cause of the fire and assess future remedial or other actions including potential insurance recoveries. The responsibility for total costs to replace the damaged components, which are estimated to be up to $4 million, is yet to be determined. During the current quarter, the Company incurred approximately $2 million of repair costs which may, in whole or in part, be recoverable. The turbine returned to service in September 2013.

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. For previously reported periods prior to the three months ended December 31, 2011, the Company used EBITDA which was defined as earnings before finance expense, income tax expense and depreciation and amortization. Commencing with the Company's December 31, 2011 year-end, the reported measure was changed from EBITDA to adjusted EBITDA which was defined to also exclude impairments, foreign exchange gains or losses and gains on disposals. 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. All comparative EBITDA amounts for quarters prior to those ended on December 31, 2011 were revised to reflect this change to adjusted EBITDA. A reconciliation of adjusted EBITDA to net income is as follows:

(unaudited, $millions)	Three months ended							
	Sep 30 2013	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**
Revenues and other income	380	321	365	296	394	261	376	407
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expenses	(229)	(217)	(230)	(223)	(243)	(196)	(224)	(257)
Adjusted EBITDA	**151**	**104**	**135**	**73**	**151**	**65**	**152**	**150**
Depreciation and amortization	(54)	(58)	(58)	(62)	(52)	(53)	(54)	(62)
Impairments	(6)	-	-	-	-	(74)	-	-
Foreign exchange loss	(1)	-	-	-	-	-	-	-
Gains on disposals	-	-	-	15	-	-	-	93
Finance expense	(18)	(20)	(22)	(21)	(18)	(18)	(18)	(29)
Income tax (expense) recovery	(13)	(3)	(7)	14	(18)	22	(14)	-
Net income (loss)	**59**	**23**	**48**	**19**	**63**	**(58)**	**66**	**152**
Net income (loss) attributable to:								
Non-controlling interests	15	3	14	4	24	(26)	26	68
Shareholders of the Company	44	20	34	15	39	(32)	40	84
Net income (loss)	**59**	**23**	**48**	**19**	**63**	**(58)**	**66**	**152**

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)	Three months ended September 30		Nine months ended September 30	
	2013	2012	2013	2012
Net cash flows from operating activities per Consolidated Statements of Cash Flows	**83**	**75**	**340**	**213**
Add (deduct) items included in calculation of net cash flows from operating activities per Consolidated Statements of Cash Flows:				
Interest paid	15	14	49	37
Miscellaneous financing charges paid and realized loss on the settlement of interest rate derivative contracts included in other items of non-cash adjustments to reconcile net income to net cash flows from operating activities	1	3	4	12
Income taxes paid	3	1	5	6
Change in non-cash operating working capital	32	53	(35)	94
	51	71	23	149
Finance expense excluding unrealized changes on interest rate derivative contracts and amortization and accretion charges	(18)	(17)	(57)	(60)
Current income tax expense (recovery)	6	(1)	4	(4)
Funds from operations	**122**	**128**	**310**	**298**

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)	Three months ended September 30		Nine months ended September 30	
	2013	2012	2013	2012
Funds from operations ($millions)	**122**	**128**	**310**	**298**
Weighted average common shares outstanding (millions)	70.83	69.52	70.49	65.80
Weighted average exchangeable common limited partnership units of CPLP outstanding (millions)	28.44	28.44	28.44	31.87
Weighted average shares and partnership units outstanding (millions)	99.27	97.96	98.93	97.67
Cash flow per share ($)	**1.23**	**1.31**	**3.13**	**3.05**

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. The measure is calculated as funds from operations less sustaining capital expenditures.

(unaudited, $millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2013	**2012**	**2013**	**2012**
Funds from operations	**122**	**128**	**310**	**298**
Less sustaining capital expenditures	9	17	68	82
Adjusted funds from operations	113	111	242	216
Common share dividends declared	23	22	67	62
Distributions to exchangeable common limited partnership unitholders of CPLP declared	9	9	27	30
Preferred share dividends declared	5	1	14	4
Total dividends and distributions declared	37	32	108	96
Discretionary cash flow	**76**	**79**	**134**	**120**

Normalized earnings attributable to common shareholders and normalized earnings per share

The Company uses 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 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. A reconciliation of net income (loss) attributable to shareholders to normalized earnings attributable to common shareholders, and basic earnings (loss) per share to normalized earnings per share is as follows:

(unaudited, $millions except basic earnings (loss) per share and number of common shares and normalized earnings per share)	Three months ended							
	Sep 30 2013	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**
Basic earnings (loss) per share	**0.55**	**0.20**	**0.44**	**0.19**	**0.55**	**(0.50)**	**0.66**	**1.47**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income	**44**	**20**	**34**	**15**	**39**	**(32)**	**40**	**84**
Preferred share dividends	(5)	(6)	(3)	(2)	(1)	(2)	(1)	(2)
Earnings (loss) attributable to common shareholders	39	14	31	13	38	(34)	39	82
Income tax expense related to change in income tax rate applicable to North East U.S.	6	-	-	-	-	-	-	-
Restructuring charges	4	2	-	-	-	-	-	-
Impairment loss on North East U.S. assets	3	-	-	-	-	37	-	-
Unrealized changes in fair value of CPLP's derivative instruments	(1)	3	(6)	12	(4)	4	(12)	2
Unrealized changes in fair value of Capital Power Income L.P.'s (CPILP) derivative instruments	-	-	-	-	-	-	-	(1)
Gain on sale of hydro facilities	-	-	-	(9)	-	-	-	-
Genesee 1 unplanned outage costs due to plant research and development project	-	-	-	-	4	-	-	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	-	-	-	-	-	(2)	-	1
Gain on sale of CPILP	-	-	-	-	-	-	-	(60)
Gain on settlement of pension expense from sale of CPILP	-	-	-	-	-	-	-	(3)
Gain on sale of Taylor Coulee Chute	-	-	-	-	-	-	-	(1)
Normalized earnings attributable to common shareholders	**51**	**19**	**25**	**16**	**38**	**5**	**27**	**20**
Weighted average number of common shares outstanding (millions)	70.83	70.48	70.15	69.84	69.52	68.51	59.18	55.64
Normalized earnings per share	**0.72**	**0.27**	**0.36**	**0.23**	**0.55**	**0.07**	**0.46**	**0.36**

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

Financial Highlights

(unaudited, $ millions, except per share amounts)	Three months ended September 30		Nine months ended September 30	
	2013	**2012**	**2013**	**2012**
Revenues and other income	380	394	1,066	1,031
Adjusted EBITDA [1]	151	151	390	368
Net income	59	63	130	71
Net income attributable to shareholders of the Company	44	39	98	47
Normalized earnings attributable to common shareholders [1]	51	38	95	70
Basic earnings per share ($)	0.55	0.55	1.19	0.65
Diluted earnings per share ($) [2]	0.51	0.55	1.14	0.63
Normalized earnings per share ($) [1]	0.72	0.55	1.35	1.06
Funds from operations [1]	122	128	310	298
Cash flow per share ($) [1]	1.23	1.31	3.13	3.05
Purchase of property, plant and equipment and other assets	422	150	884	433
Discretionary cash flow [1]	76	79	134	120
Dividends per common share, declared ($)	0.3150	0.3150	0.9450	0.9450
Dividends per Series 1 preferred share, declared ($)	0.2875	0.2875	0.8625	0.8625
Dividends per Series 3 preferred share, declared ($)	0.2875	n/a	0.8901	n/a
Dividends per Series 5 preferred share, declared ($)	0.2813	n/a	0.6142	n/a

	As at	
	September 30, 2013	**December 31, 2012**
Loans and borrowings including current portion	2,063	1,659
Total assets	5,815	5,134

[1] 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.

[2] 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.

Normalized earnings and normalized earnings per share

Refer to Results by Plant Category and Other and Consolidated Other Expenses and Non-Controlling Interests for detailed discussion of the results for the quarter on a comparative basis.

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

Funds from operations

Funds from operations for the three months ended September 30, 2013 decreased in comparison to funds from operations for the three months ended September 30, 2012 generally due to the decrease in net income.

Significant Events

Purchase of interest in Shepard Energy Centre

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 $860 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, under the new accounting standard for joint arrangements, as a joint operation.

Agreement to sell North East U.S. assets and refocusing of business

On August 28, 2013, Capital Power announced that it has entered into an agreement with Emera Inc. to sell its three North East U.S. combined cycle, natural gas-fired power generation facilities for US$541 million. This transaction is expected to close in the fourth quarter of 2013, subject to regulatory approvals and other customary closing conditions. The timing of the closing may be affected by the U.S. Federal government shutdown and debt ceiling issues which could impact the Federal Energy Regulatory Commission's regulatory approval processing time. The Company has recorded a pre-tax impairment loss of $6 million in the third quarter of 2013. When the sale is finalized, Capital Power expects to record a gain on disposal that includes the related accumulated foreign currency translation gains of $51 million that, as at September 30, 2013, were recorded in other reserves as accumulated other comprehensive income.

The Company incurred pre-tax restructuring costs of approximately $12 million, cumulatively in the second and third quarters of 2013, as a result of its decision to exit the North East U.S. market and to refocus its merchant power business in Alberta. Future expected impacts include efficiencies in operations and maintenance spending while approximately 160 employee positions will have been eliminated by the end of 2013 resulting in approximately 700 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 costs savings consist primarily of employee compensation including benefits less margins from the discontinued trading operations.

$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) has assigned a rating of P-3 and DBRS Limited (DBRS) has assigned a rating of Pfd-3 (low) for the Series 5 Shares.

Subsequent Event

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. The underwriters for the sale of common shares were granted an option to purchase up to an additional 1,440,000 common shares at the issue price to cover over-allotments, if any. The over-allotment option is exercisable, in whole or in part, by the underwriters at any time up to 30 days after the closing of the offering. Capital Power will not receive any of the proceeds from EPCOR's sale of common shares. The October 10, 2013 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%. If the over-allotment option is fully exercised, EPCOR's ownership interest will be further reduced to 18%. 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 has 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 September 30, 2013 was approximately $342 million. Also, EPCOR may only elect two of Capital Power's directors compared to four previously.

Plant Summary

		Three months ended September 30					
		2013	**2012**	**2013**	**2012**	**2013**	**2012**
	Energy source	**Electricity generation** (GWh) [1]		**Plant availability** (%) [2]		**Plant revenues** (unaudited, $ millions) [3]	
Total electricity generation, average plant availability and total plant revenues excluding acquired Sundance PPA		4,317	4,575	97%	97%	296	283
Alberta commercial plants and acquired Sundance PPA							
Genesee 3 [4]	Coal	480	507	99%	100%	38	38
Keephills 3	Coal	483	489	100%	100%	40	38
Clover Bar Energy Centre 1, 2 and 3	Natural gas	45	130	93%	97%	16	25
Joffre	Natural gas	109	87	100%	98%	19	17
Halkirk [5]	Wind	76	n/a	89%	n/a	8	n/a
Clover Bar Landfill Gas	Landfill gas	4	8	66%	92%	1	1
Alberta commercial plants – owned		1,197	1,221	96%	99%	122	119
Acquired Sundance PPA	Coal	659	738	83%	97%	59	59
		1,856	1,959	90%	98%	181	178
Alberta contracted plants							
Genesee 1	Coal	819	755	98%	93%		
Genesee 2	Coal	840	815	100%	99%		
		1,659	1,570	99%	96%	80	69
Ontario and British Columbia contracted plants							
Island Generation	Natural gas	14	8	100%	100%	9	10
Kingsbridge 1	Wind	12	15	95%	99%	-	1
Quality Wind [5]	Wind	68	n/a	100%	n/a	7	n/a
Brown Lake [6]	Water flows	n/a	14	n/a	99%	n/a	1
Miller Creek [6]	Water flows	n/a	22	n/a	71%	n/a	-
		94	59	99%	97%	16	12
North East U.S. commercial plants							
Bridgeport	Natural gas	690	905	93%	95%	30	33
Rumford	Natural gas	57	229	100%	97%	7	13
Tiverton	Natural gas	434	416	96%	99%	21	18
		1,181	1,550	95%	97%	58	64
North Carolina U.S. contracted plants							
Roxboro	Mixed [7]	69	64	97%	97%	7	5
Southport	Mixed [7]	117	111	99%	100%	13	14
		186	175	98%	99%	20	19

		Nine months ended September 30					
		2013	2012	2013	2012	2013	2012
	Energy source	**Electricity generation** (GWh) [1]		**Plant availability** (%) [2]		**Plant revenues** (unaudited, $ millions) [3]	
Total electricity generation, average plant availability and total plant revenues excluding acquired Sundance PPA		12,205	12,296	93%	92%	893	703
Alberta commercial plants and acquired Sundance PPA							
Genesee 3 [4]	Coal	1,454	1,359	99%	93%	127	82
Keephills 3	Coal	1,236	1,392	88%	98%	112	80
Clover Bar Energy Centre 1, 2 and 3	Natural gas	287	297	97%	97%	77	43
Joffre	Natural gas	319	276	99%	97%	57	41
Halkirk [5]	Wind	329	n/a	95%	n/a	35	n/a
Clover Bar Landfill Gas	Landfill gas	11	25	84%	91%	2	2
Alberta commercial plants – owned		3,636	3,349	96%	96%	410	248
Acquired Sundance PPA	Coal	2,062	2,093	91%	94%	176	127
		5,698	5,442	94%	96%	586	375
Alberta contracted plants							
Genesee 1	Coal	2,108	2,336	85%	95%		
Genesee 2	Coal	2,332	2,247	93%	91%		
		4,440	4,583	89%	93%	176	207
Ontario and British Columbia contracted plants							
Island Generation	Natural gas	14	74	100%	100%	29	30
Kingsbridge 1	Wind	71	74	96%	99%	4	5
Quality Wind [5]	Wind	264	n/a	99%	n/a	26	n/a
Brown Lake [6]	Water flows	n/a	45	n/a	99%	n/a	3
Miller Creek [6]	Water flows	n/a	42	n/a	65%	n/a	-
		349	235	99%	97%	59	38
North East U.S. commercial plants							
Bridgeport	Natural gas	2,281	2,049	91%	76%	131	84
Rumford	Natural gas	114	349	91%	93%	16	23
Tiverton	Natural gas	898	1,222	80%	92%	49	48
		3,293	3,620	88%	84%	196	155
North Carolina U.S. contracted plants							
Roxboro	Mixed [7]	179	180	93%	92%	17	16
Southport	Mixed [7]	308	329	98%	94%	35	39
		487	509	96%	94%	52	55

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 In this summary, plant revenue represents revenue generated directly from plant activity and does not include portfolio or mark-to-market generated revenue.

4 Genesee 3 returned to service on January 15, 2012 after an unscheduled outage which commenced on November 11, 2011.

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

6 Brown Lake and Miller Creek were disposed of on October 12, 2012.

7 The energy sources for the Roxboro and Southport plants are wood waste, tire-derived fuel and coal.

Portfolio Optimization

The significant positions and results of portfolio optimization activities were as follows:

	Unit	Three months ended September 30 2013	2012	Nine months ended September 30 2013	2012	Year ended December 31, 2012
Alberta portfolio						
Hedged position [1]	Percentage sold forward at beginning of period (%)	63	91	49	48	48
Realized power price [2]	$/MWh	94	81	85	74	72
Spot power price averages	$/MWh	84	78	90	59	64
North East U.S portfolio						
Hedged position	Approximate average percentage hedged at the beginning of the period (%)	78	46	72	46	46

[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 commercial contracted sales and portfolio optimization activities.

Consolidated Net Income

The primary factors contributing to the change in net income for the three months ended September 30, 2013 compared with the three months ended September 30, 2012 are presented below; detailed analysis of these items can be found in the Results by Plant Category and Other and the Consolidated Other Expenses and Non-controlling Interests sections.

(unaudited, $ millions)	Three months	Nine months
Consolidated net income for the periods ended September 30, 2012	**63**	**71**
Increase (decrease) in adjusted EBITDA for Alberta contracted plants	17	(12)
(Decrease) increase in adjusted EBITDA for Alberta commercial plants and portfolio optimization	(8)	45
(Increase) decrease in impairment expense	(6)	68
Changes in unrealized fair value of energy derivative instruments and Atlantic Power shares	(6)	(3)
(Decrease) in adjusted EBITDA for other portfolio activities	(5)	(16)
Increase in adjusted EBITDA for North Carolina U.S. contracted plants	2	2
(Increase) in depreciation and amortization expense	(2)	(11)
(Decrease) in adjusted EBITDA for North East U.S. commercial plants and portfolio optimization	(1)	(4)
Increase in adjusted EBITDA for Ontario and British Columbia contracted plants	1	14
Increase (decrease) in net unrealized gains on interest rate derivative contracts included in finance expense	1	(7)
(Increase) in finance expense excluding interest rate derivative contracts	(1)	(6)
Decrease in realized losses on settled interest rate derivative contracts included in finance expense	-	7
(Decrease) in Corporate adjusted EBITDA	-	(4)
Other	(1)	(1)
(Decrease) increase in income before tax	(9)	72
Decrease (increase) in income tax expense	5	(13)
(Decrease) increase in net income	**(4)**	**59**
Consolidated net income for the periods ended September 30, 2013	**59**	**130**

Results by Plant Category and Other

The Company reports results of operations in the following categories: (i) Alberta commercial plants, acquired Sundance PPA and portfolio optimization, (ii) Alberta contracted plants, (iii) Ontario and British Columbia contracted plants, (iv) North East U.S. commercial plants and portfolio optimization, (v) North Carolina U.S. contracted plants, (vi) Other portfolio activities, and (vii) Corporate.

Financial results

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2013	**2012**	**2013**	**2012**
Revenues and other income				
Alberta commercial plants, acquired Sundance PPA and portfolio optimization [1]	186	206	518	525
Alberta contracted plants	80	69	176	207
Ontario and British Columbia contracted plants[2]	16	12	59	38
North East U.S. commercial plants and portfolio optimization	63	62	204	155
North Carolina U.S. contracted plants	20	19	52	55
Other portfolio activities	16	8	51	22
Corporate	1	1	4	11
Interplant category transaction eliminations	(5)	(1)	(8)	(3)
	377	376	1,056	1,010
Unrealized changes in fair value of energy derivative instruments and Atlantic Power shares	3	18	10	21
	380	**394**	**1,066**	**1,031**
Adjusted EBITDA [3]				
Alberta commercial plants, acquired Sundance PPA and portfolio optimization [1]	105	113	300	255
Alberta contracted plants	55	38	106	118
Ontario and British Columbia contracted plants [2]	9	8	41	27
North East U.S. commercial plants and portfolio optimization	11	12	22	26
North Carolina U.S. contracted plants	2	-	4	2
Other portfolio activities	(1)	4	(5)	11
Corporate	(31)	(31)	(87)	(83)
	150	144	381	356
Unrealized changes in fair value of energy derivative instruments and Atlantic Power shares	1	7	9	12
	151	**151**	**390**	**368**

[1] Alberta commercial plants, acquired Sundance PPA and portfolio optimization includes Halkirk as of its date of commissioning of December 1, 2012. Revenues and expenses related to commissioning activities, prior to the dates of commissioning, were capitalized as part of the cost of the facility.

[2] Ontario and British Columbia contracted plants include Quality Wind as of its date of commissioning of November 6, 2012. Revenues and expenses related to commissioning activities, prior to the dates of commissioning, were capitalized as part of the cost of the facility.

[3] The results by plant category and other, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

	Three months ended September 30		Nine months ended September 30	
Spot price averages	**2013**	**2012**	**2013**	**2012**
Alberta power ($/MWh)	84	78	90	59
New England mass hub (US$/MWh)	42	37	57	33
Alberta natural gas (AECO) ($/gigajoule (Gj)) [1]	2.32	2.16	2.87	2.01

[1] 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

Alberta commercial plants, acquired Sundance PPA and portfolio optimization [1]	Three months ended September 30		Nine months ended September 30	
	2013	2012	2013	2012
Electricity generation (GWh)	1,856	1,959	5,698	5,442
Availability (%)	90	98	94	96
Revenues and other income (unaudited, $ millions)	186	206	518	525
Adjusted EBITDA (unaudited, $ millions) [2]	105	113	300	255

[1] Alberta commercial plants, acquired Sundance PPA and portfolio optimization includes the Company's interest in the acquired Sundance PPA.

[2] The financial results by plant category, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

For the three months ended September 30, 2013, production decreased compared with the corresponding period of 2012 primarily due to lower generation from Clover Bar Energy Centre and from Sundance partly offset by the addition of Halkirk. During the third quarter of 2013, Sundance experienced an unplanned outage while Clover Bar Energy Centre's generation decreased primarily due to the Unit 2 maintenance outage. Production slightly increased on a year-to-date basis primarily due to the addition of Halkirk partly offset by the impact of plant outages. Overall availability for the Alberta commercial plants was likewise affected by the same factors.

The average Alberta spot power price was $84/MWh and $90/MWh for the three and nine months ended September 30, 2013, respectively, which reflected increased spot prices compared with the corresponding periods of 2012 which had average spot prices of $78/MWh and $59/MWh, respectively. During the third quarter of 2013, power prices were pushed higher as plant outages impacted availability and demand for power was strong. Prices were relatively low in January and February 2013 but significantly increased in March 2013 continuing through to September 2013 reflecting the impact of Alberta market plant outages and demand.

Decreased revenues for the three months ended September 30, 2013 compared with the same period in 2012 reflected the impact of spot power prices on Capital Power's unhedged position and higher Alberta production including the addition of Halkirk.

The decrease in adjusted EBITDA for the three months ended September 30, 2013 compared with the corresponding period in 2012 was primarily driven by losses realized on trading related to portfolio optimization activities and lower generation at the Clover Bar Energy Centre. The addition of Halkirk increased adjusted EBITDA on a year-to-date basis and partly offset the decreased adjusted EBITDA from portfolio optimization activities.

Alberta contracted plants

Alberta contracted plants	Three months ended September 30		Nine months ended September 30	
	2013	2012	2013	2012
Electricity generation (GWh)	1,659	1,570	4,440	4,583
Availability (%)	99	96	89	93
Revenues and other income (unaudited, $ millions)	80	69	176	207
Adjusted EBITDA (unaudited, $ millions) [1]	55	38	106	118

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

For the three months ended September 30, 2013, the operational and financial results for the Alberta contracted plants reflected stronger performance compared to the three months ended September 30, 2012. Both revenues and adjusted EBITDA increased since, in the third quarter of 2012, the plants experienced a forced outage of 8 days which resulted from a trial project intended to increase the marketability of fly ash by-product. Revenues for the third quarter also increased in 2013 compared with 2012 due to higher Alberta power prices which, in combination with the higher availability, increased availability incentive revenues. For the nine months ended September 30, 2013, both revenues and adjusted EBITDA decreased compared to the nine months ended September 30, 2012. These results also reflected the impact of the 2013 second quarter planned outage at Genesee 1 and unplanned outages at Genesee 1 and 2 that reduced production and revenues and increased availability penalties under the plants' Power Purchase Arrangement (PPA). Revenues also decreased due to required reductions in some of the indices embedded in the plants' PPA used in determining capacity payments.

Ontario and British Columbia contracted plants

	Three months ended September 30		Nine months ended September 30	
Ontario and British Columbia contracted plants	**2013**	**2012**	**2013**	**2012**
Electricity generation (GWh)	94	59	349	235
Availability (%)	99	97	99	97
Revenues and other income (unaudited, $ millions)	16	12	59	38
Adjusted EBITDA (unaudited, $ millions) [1]	9	8	41	27

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

For the three and nine months ended September 30, 2013 compared with the same periods in 2012, increased generation, revenues and adjusted EBITDA reflected the addition of Quality Wind which commenced commercial operations in the fourth quarter of 2012. The Kingsbridge 1 facility incurred approximately $2 million of repair expenses in the third quarter of 2013 related to the second quarter turbine fire. The plant availability for Island Generation was 100% which resulted in revenues and adjusted EBITDA being based on strong deemed generation in accordance with the underlying contract and consistent with the first three quarters of 2012.

North East U.S. commercial plants and portfolio optimization

	Three months ended September 30		Nine months ended September 30	
North East U.S. commercial plants	**2013**	**2012**	**2013**	**2012**
Electricity generation (GWh)	1,181	1,550	3,293	3,620
Availability (%)	95	97	88	84
Revenues and other income (unaudited, $ millions)	63	62	204	155
Adjusted EBITDA (unaudited, $ millions) [1]	11	12	22	26

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

For the three and nine months ended September 30, 2013, the three New England plants and related portfolio optimization contributed $11 million and $22 million, respectively, to the Company's adjusted EBITDA. This was relatively consistent with the results for the same periods of 2012 although generation volumes decreased primarily due to planned outages and lower dispatch of the Rumford facility during 2013. Other quarter-over-quarter changes in revenues and adjusted EBITDA were attributed to portfolio optimization activities.

North Carolina U.S. contracted plants

	Three months ended September 30		Nine months ended September 30	
North Carolina U.S contracted plants	**2013**	**2012**	**2013**	**2012**
Electricity generation (GWh)	186	175	487	509
Availability (%)	98	99	96	94
Revenues and other income (unaudited, $ millions)	20	19	52	55
Adjusted EBITDA (unaudited, $ millions) [1]	2	-	4	2

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

For the three and nine months ended September 30, 2013, the performance of the North Carolina U.S. contracted plants was relatively consistent with the results for the comparable quarter and year-to-date of 2012 with a slight year-to-date revenue decrease due to lower renewable energy credits (REC) pricing. The REC pricing will be lower throughout 2013 and 2014 with increased pricing in 2015. Adjusted EBITDA on a comparative basis by period was positively impacted since, during the third quarter of 2012, Southport incurred approximately $1 million for unanticipated costs related to physical coal fuel inventory and Roxboro incurred approximately $1 million for reclassification of maintenance costs from capital to operating expenses.

Other portfolio activities

Other portfolio activities	Three months ended September 30		Nine months ended September 30	
	2013	2012	2013	2012
Revenues and other income (unaudited, $ millions)	16	8	51	22
Adjusted EBITDA (unaudited, $ millions) [1]	(1)	4	(5)	11

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

Other portfolio activities reflect revenues and adjusted EBITDA for natural gas and emissions trading activities. Revenues were higher for the three and nine months ended September 30, 2013 compared with the same periods in 2012 due to higher trading volumes. However, adjusted EBITDA for the three and nine months ended September 30, 2013 reflected higher losses than in 2012 on such transactions partly offset by reduced provisions for estimated future losses on certain natural gas contracts. During the three and nine months ended September 30, 2012, a reduction in the provision was also recorded but was greater than that recorded in 2013.

Corporate

Corporate	Three months ended September 30		Nine months ended September 30	
	2013	2012	2013	2012
Revenues and other income (unaudited, $ millions)	1	1	4	11
Adjusted EBITDA (unaudited, $ millions) [1]	(31)	(31)	(87)	(83)

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

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

The Company incurred restructuring charges of approximately $9 million in the three months ended September 30, 2013 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. On a year-to-date basis, the total restructuring charges incurred were approximately $12 million. Reclassification of certain expenses from plant operations resulted in decreased adjusted EBITDA for the Corporate category for the three and nine months ended September 30, 2013 compared with the same periods in 2012. The restructuring charges and expense reclassification were partly offset by lower compensation costs following the restructuring and the third quarter reduction of long-term disability and performance incentive expenses.

Unrealized changes in fair value of energy derivative instruments and Atlantic Power shares

Unrealized changes in fair value of energy derivative instruments and Atlantic Power shares	Three months ended September 30		Nine months ended September 30	
	2013	2012	2013	2012
Revenues and other income (unaudited, $ millions)	3	18	10	21
Adjusted EBITDA (unaudited, $ millions) [1]	1	7	9	12

[1] The financial results by plant category, 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 energy derivative instruments and, until its disposal in February 2012, the Company's investment in Atlantic Power.

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

($ millions)	Three months ended September 30			
	2013	2012	2013	2012
Unrealized changes in fair value of energy derivative instruments and Atlantic Power shares	**Revenues and other income**		**Adjusted EBITDA**	
Unrealized gains (losses) on Alberta energy derivatives	(1)	17	(2)	6
Unrealized gains on Bridgeport heat rate option	1	3	1	**3**
Unrealized gains (losses) on natural gas derivatives	3	(1)	3	(1)
Other	-	(1)	(1)	(1)
	3	18	1	7

($ millions)	Nine months ended September 30			
	2013	2012	2013	2012
Unrealized changes in fair value of energy derivative instruments and Atlantic Power shares	**Revenues and other income**		**Adjusted EBITDA**	
Unrealized gains (losses) on Alberta energy derivatives	(11)	23	(11)	12
Unrealized gains on Bridgeport heat rate option	13	4	14	4
Unrealized gains on natural gas derivatives	9	-	10	2
Reversal of unrealized gain on Atlantic Power shares	-	(5)	-	(5)
Other	(1)	(1)	(4)	(1)
	10	21	9	12

Alberta electricity portfolio activities accounted for unrealized net losses of $2 million during the third quarter of 2013 and unrealized net gains of $6 million in the third quarter of 2012. Unrealized net losses of $11 million and unrealized net gains of $12 million were incurred for the nine months ended September 30, 2013 and 2012, respectively. The unrealized net losses reflected the reversal of prior periods' unrealized net gains on contracts which settled during the applicable period. Additionally, the 2013 third quarter and year-to-date net unrealized losses included the impact of increased forward Alberta power prices combined with a net short position on electricity derivative contracts.

Upon acquisition of the New England plants in the second quarter of 2011, the Company acquired heat rate options related to the Bridgeport facility. For the three and nine months ended September 30, 2013, the Company recognized unrealized net gains of $1 million and $14 million, respectively, on the Bridgeport heat rate options. These unrealized net gains reflected the reversal of prior periods' unrealized net losses.

Natural gas portfolio activities accounted for unrealized net gains of $3 million during the third quarter of 2013 and unrealized net losses of $1 million in the third quarter of 2012. Unrealized net gains of $10 million and $2 million were incurred for the nine months ended September 30, 2013 and 2012, respectively. These unrealized net gains and losses primarily reflected the impact of fluctuating forward natural gas prices on changes in the portfolio position during each of the quarters.

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. The sale resulted in a realized gain of $4 million which was included in the Corporate category.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2013	2012	2013	2012
Interest on borrowings less capitalized interest	(17)	(14)	(53)	(46)
Realized losses on the settlement of interest rate derivative contracts	-	-	-	(7)
Other finance expense – sundry interest and guarantee and other fees	(1)	(3)	(4)	(4)
	(18)	(17)	(57)	(57)
Unrealized gains representing changes in the fair value of interest rate derivative contracts	1	-	1	8
Other finance expense – amortization and accretion charges	(1)	(1)	(4)	(5)
Total finance expense	(18)	(18)	(60)	(54)
Depreciation and amortization	(54)	(52)	(170)	(159)
Impairments	(6)	-	(6)	(74)
Foreign exchange loss	(1)	-	(1)	-
Income tax expense	(13)	(18)	(23)	(10)
Net income attributable to non-controlling interests	15	24	32	24

Finance expense

Finance expense for the three months ended September 30, 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 the nine months ended September 30, 2013 compared with the nine months ended September 30, 2012 was primarily due to increased borrowings related to capital projects and the varying levels of capitalized interest as certain projects were completed and other projects commenced.

Depreciation and amortization

Depreciation and amortization for the three months and nine months ended September 30, 2013 increased $2 million and $11 million compared with the same periods in the prior year primarily due to the addition of depreciation on the Halkirk facility which commenced operations in the fourth quarter of 2012 partly offset by decreases due to the revised useful lives of coal plants in accordance with the federal regulations. 2013 year-to-date depreciation and amortization also increased compared to 2012 year-to-date depreciation and amortization due to the reclassification of coal mine stripping costs from energy purchases and fuel. Depreciation and amortization decreased for the third quarter of 2013 compared to the same period in 2012 because of the change in status of the North East U.S. assets to assets held for sale at which point no further depreciation and amortization will be expensed.

Impairments

An asset impairment charge of $6 million related to the pending sale of the North East U.S. assets was recognized in the three and nine months ended September 30, 2013. The impairment recognized in the second quarter of 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.

Income tax expense

Income tax expense decreased $5 million for the three months ended September 30, 2013 compared with the same period in 2012 due to higher U.S. losses partly offset by changes in unrecognized tax benefits. Income tax expense increased $13 million for the nine months ended September 30, 2013 compared with the same period in the prior year primarily due to the 2012 tax recovery related to the impairment loss on North East U.S. assets and changes in unrecognized tax benefits partly offset by higher U.S. losses in 2013.

Non-controlling interests

For the three and nine months ended September 30, 2013, approximately 29% (nine months ended September 30, 2012 – 32%) 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 April 5, 2012 exchange of exchangeable common limited partnership units for common shares of Capital Power reduced its interest in CPLP from 39% to 29%. 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.

Other Comprehensive Income

($ millions)	Three months ended September 30			
	2013		2012	
Other comprehensive income	**Before tax**	**After tax**	**Before tax**	**After tax**
Net unrealized gains on derivatives designated as cash flow hedges	-	-	37	31
Net realized losses and ineffective portion of unrealized losses on cash flow hedges reclassified to revenues and/or energy purchases and fuel	3	2	4	3
	3	2	41	34
Unrealized foreign exchange (losses) on the translation of foreign operations	(9)	(9)	(15)	(15)
	(6)	(7)	26	19
Income taxes on above items	(1)	n/a	(7)	n/a
	(7)	**(7)**	**19**	**19**

($ millions)	Nine months ended September 30			
	2013		2012	
Other comprehensive income	**Before tax**	**After tax**	**Before tax**	**After tax**
Net unrealized (losses) gains on derivatives designated as cash flow hedges	(79)	(65)	82	68
Net realized losses (gains) and ineffective portion of unrealized losses (gains) on cash flow hedges reclassified to revenues and/or energy purchases and fuel	50	41	(26)	(22)
	(29)	(24)	56	46
Unrealized foreign exchange gains (losses) on the translation of foreign operations	14	14	(15)	(15)
Actuarial losses on defined benefit plans	-	-	(4)	(3)
	(15)	(10)	37	28
Income taxes on above items	5	n/a	(9)	n/a
	(10)	**(10)**	**28**	**28**

For the three months ended September 30, 2013, net unrealized losses (after income taxes) on derivative instruments designated as cash flow hedges (for the effective portion) of $nil compared with net unrealized gains of $31 million for the same period in 2012 were recorded in other comprehensive income. Net realized losses (after income taxes) of $2 million for the three months ended September 30, 2013 and net realized losses of $3 million for the three months ended September 30, 2012 were reclassified to revenues and energy purchases and fuel, as appropriate. For the three months ended September 30, 2013, net unrealized losses (after income taxes) of $9 million and, for the three months ended September 30, 2012, net unrealized losses (after income taxes) of $15 million representing foreign exchange losses on the translation of foreign operations were also recorded in other comprehensive income.

For the nine months ended September 30, 2013, net unrealized losses (after income taxes) on derivative instruments designated as cash flow hedges (for the effective portion) of $65 million compared with net unrealized gains of $68 million for the same period in 2012 were recorded in other comprehensive income. Net realized losses (after income taxes) of $41 million for the nine months ended September 30, 2013 and net realized gains of $22 million for the nine months ended September 30, 2012 were reclassified to revenues and energy purchases and fuel, as appropriate. For the nine months ended September 30, 2013, net unrealized gains (after income taxes) of $14 million representing foreign exchange losses on the translation of foreign operations were also recorded in other comprehensive income.

Financial Position

The significant changes in the Consolidated Statements of Financial Position from December 31, 2012 to September 30, 2013 were as follows:

(unaudited, $ millions)	September 30, 2013	December 31, 2012	Increase (decrease)	Increase (decrease) due to North East U.S. assets held for sale	Increase (decrease) due to Other	Primary other changes
Trade and other receivables	250	354	(104)	(5)	(99)	Primarily due to the reclassification of Shepard deposit to property, plant and equipment, the timing of the settlement of trade receivables, lower trade receivables due to the Genesee 1 and 2 and Keephills 3 outages, and the receipt of a land lease renewal holdback related to the sale of the hydro facilities in 2012 partly offset by higher trade receivables from the Alberta Electric System Operator resulting from higher power prices.
Inventories	68	72	(4)	(9)	5	
Assets held for sale	609	-	609	609	-	North East U.S. assets
Finance lease receivables	445	461	(16)	-	(16)	Primarily due to payments received in respect of the Quality Wind and Kingsbridge 1 facilities and adjustments of Quality Wind's construction costs.
Other financial assets	72	60	12	-	12	Primarily due to payment of K2 cash call.
Net derivative financial instruments assets	11	13	(2)	3	(5)	Primarily due to the impact of increasing Alberta forward power prices on the fair value of power derivative contracts.
Intangible assets	345	316	29	(14)	43	Primarily due to the purchase of emission credits.
Property, plant and equipment	3,776	3,628	148	(581)	729	Primarily due to capital additions (most significantly, Shepard and Port Dover & Nanticoke) partly offset by depreciation and amortization.
Trade and other payables	208	210	(2)	(10)	8	
Loans and borrowings (including current portion)	2,063	1,659	404	-	404	Primarily due to net proceeds from credit facilities used to finance the second tranche payment for Shepard and the impact of translation on U.S. denominated debt.
Provisions (including current portion)	187	238	(51)	(37)	(14)	Primarily due to the settlement of accrued 2012 short-term incentive and changes to decommissioning provisions.
Liabilities related to assets held for sale	68	-	68	68	-	North East U.S. assets
Net deferred tax liabilities	45	42	3	(18)	21	Primarily due to taxable temporary differences that will reverse in the future partly offset by losses generated by U.S. operations.
Share capital	2,119	1,903	216	-	216	Issuance of preferred shares.

Liquidity and Capital Resources

(unaudited, $ millions)	Nine months ended September 30		
Cash inflows (outflows)	**2013**	**2012**	**Increase (decrease)**
Operating activities	340	213	127
Investing activities	(848)	(350)	(498)
Financing activities	485	100	385

Operating activities

Cash flows from operating activities for year-to-date 2013 increased compared with year-to-date 2012 primarily due to reductions in trade and other receivables.

Investing activities

The cash flows used in investing activities for the nine months ended September 30, 2013 included $884 million for capital expenditures and investments, most significantly, the Shepard and Port Dover & Nanticoke projects.

Capital expenditures and investments

(unaudited, $ millions)	**Pre-2013**	**Nine months ended September 30, 2013**	**Actual or Projected [1, 3]**	**Budget**	**Timing**
Quality Wind	419	(6)	413	455	Completed 4th quarter 2012
Halkirk	314	6	320	357	Completed 4th quarter 2012
Port Dover & Nanticoke	68	179	340	340	Projected completion 4th quarter 2013
K2	3	12	291	291	Projected completion 2015
Shepard Energy Centre	50	599	860	860	Projected completion 2015
Subtotal growth projects		**790**			
Sustaining – plant maintenance and other		61			
Sustaining – Genesee mine lands		7			
Total capital expenditures [2]		**858**			
Emission credits		39			
Capitalized interest		(13)			
Purchase of property, plant and equipment and other assets		**884**			

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

2 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.

3 Costs for projects completed in 2012 include certain costs that 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.

Sustaining capital expenditures include spending on plant maintenance, the Genesee mine, and information technology.

Financing activities

The cash flows from financing activities during the nine months ended September 30, 2013 primarily reflected the $200 million proceeds on the March 2013 issuance of preferred shares and a net increase of $411 million in amounts issued from the credit facilities partly offset by debt repayments of $18 million partly offset by distributions to non-controlling interests, common share dividends and preferred share dividends paid of $87 million.

The Company's credit facilities consisted of:

($millions)		As at September 30, 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			208			207	
Bankers' acceptances outstanding			503			104	
U.S. dollar bank loans outstanding			41			30	
		1,200	752	448	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	**752**	**473**	**1,225**	**341**	**884**

As at September 30, 2013, the committed credit facility utilization increased $411 million compared to the utilization as at December 31, 2012 primarily due to the Shepard second tranche payment of approximately $325 million. Capital Power intends to use the proceeds from the sale of the North East U.S. facilities to permanently finance the second tranche payment for its 50% interest in Shepard by repaying amounts owed under its credit facility and to fund other ongoing capital projects. 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 club credit agreement and syndicated credit agreement was extended to July 9, 2018.

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

The loan and credit agreements require CPLP to meet certain financial covenants, including maintaining a consolidated senior debt to consolidated capitalization ratio of not more than 0.65 to 1.0 as at the end of any fiscal quarter. In addition, in the event that CPLP is assigned a credit rating by S&P that is less than BBB- or by DBRS that is less than BBB(low) (in each case with a stable outlook), then CPLP must also maintain a ratio of consolidated EBITDA to consolidated interest expense (each as defined in the credit agreements) of not less than 2.5 to 1.0 as at the end of each fiscal quarter.

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 received 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. A BBB rating is an investment grade credit rating, which enhances CPLP's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

Future cash requirements

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's estimated cash requirements for 2013 are expected to include approximately $1.1 billion for capital expenditures, approximately $33 million for CPLP distributions to EPCOR (subject to approval by the Board of Directors of CPLP's general partner), approximately $85 million for Capital Power's common share dividends, and approximately $20 million for quarterly preferred share dividends (subject to approval by Capital Power Corporation's Board of Directors). The revised estimated capital expenditures includes the $235 million Shepard second tranche payment paid in the third quarter of 2013 which was accelerated from the earlier expected payment timing of first quarter of 2014. Effective January 1, 2012, the Company launched a Dividend Re-investment Plan where shareholders may elect to reinvest their quarterly cash dividends for additional shares of Capital Power as an alternative to receiving cash dividends. The participation rate in the Dividend Re-investment Plan was approximately 28% for 2012 dividends and depending on the participation rate for 2013, cash requirements for common share dividends may differ from the above expectations.

The Company expects to fund the construction of the Port Dover & Nanticoke, 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. When construction is complete, the Company expects to put long-term financing in place. 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.

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 September 30, 2013, $208 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements and to satisfy legislated reclamation requirements. If the Company were to terminate these off-statement of financial position arrangements, the penalties or obligations would not have a material impact on the Company's financial condition, results of operations, liquidity, capital expenditures or resources.

Capital resources

(unaudited, $ millions)	**As at**	
	September 30, 2013	**December 31, 2012**
Loans and borrowings	2,063	1,659
Less cash and cash equivalents	31	53
Net debt	2,032	1,606
Non-controlling interests	836	829
Share capital	2,119	1,903
Retained earnings and other reserves	32	20
Total equity	2,987	2,752
Total capital	**5,019**	**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

The only material change to the Company's commitments since December 31, 2012 was the timing of the payment of the investment in Shepard Energy Centre which was originally expected to occur in two tranches, in the first quarters of 2013 and 2014. Both tranches totalling $562 million were paid in 2013. There were no other changes to the Company's purchase obligations and commitments since December 31, 2012 that would be material to the Company's business or financial position. For further information on contractual obligations, refer to the Company's December 31, 2012 MD&A.

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 is scheduled for October 2013 and it is anticipated that the AUC's decision will be issued no sooner than the first quarter of 2014.

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 PPA for Units 5 and 6 and thus is 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 will not meet the PPA specified force majeure tests, recorded it as an amount receivable until final resolution of the claim. The claim currently is under arbitration and an arbitration decision is not expected until 2014. The Company currently has recorded $20 million as accounts receivable on its September 30, 2013 statement of financial position. In the event that the arbitration decision results in an adverse impact to the Company, the $20 million account receivable amount may not be fully realized. If not realized, the resulting loss would be reduced by estimated insurance recoveries of up to $3 million.

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.

Transactions with Related Parties

(unaudited, $ millions)	Note	Three months ended September 30		Nine months ended September 30	
		2013	**2012**	**2013**	**2012**
EPCOR (shareholder)					
CPLP distributions paid	(a)	9	9	27	33
Purchase of distribution and transmission services	(b)	4	6	13	16
Purchase of other services	(b)	1	2	5	6
Power sales	(b)	2	3	4	7
Interest incurred on unsecured senior debt payable and expensed	(c)	3	4	14	15
Interest incurred on unsecured senior debt payable and capitalized	(c)	3	2	3	4
Repayment of unsecured senior debt payable	(c)	15	25	15	25
The City of Edmonton (sole shareholder of EPCOR)					
Power sales	(b)	9	9	28	27

	Note	As at September 30, 2013	As at December 31, 2012
EPCOR (shareholder)			
Trade and other receivables	(b)	1	1
Trade and other payables	(b)	12	17
Provision for future maintenance costs associated with EPCOR's Rossdale plant	(d)	4	4
Loans and borrowings	(c)	342	357
The City of Edmonton (sole shareholder of EPCOR)			
Trade and other receivables	(b)	5	7

(a) As at September 30, 2013 and December 31, 2012, EPCOR owned 28.441 million exchangeable common limited partnership units of CPLP (representing approximately 29% of CPLP), and 28.441 million accompanying special voting shares and one special limited voting share of Capital Power Corporation. In connection with EPCOR's unitholdings, CPLP paid distributions to EPCOR for the three months and nine months ended September 30, 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 $4 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 2013 and 2018. Since EPCOR no longer owns, directly or indirectly, at least 20% of the outstanding common 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 180 days after delivery of notice, and if it is $200 million or more, then it and the accrued interest thereon shall be payable 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 sale of the Company's North East U.S. assets, the refocusing of merchant power business on Alberta, and the future addition of Genesee 4 & 5 changes the Company's risk profile by decreasing merchant risk and increasing Alberta market concentration risk.

The decrease in EPCOR's ownership interest in the common limited partnership units of CPLP to less than 20% changes the Company's liquidity, credit and financing risks since EPCOR may demand repayment of all or any portion of the debt payable to EPCOR before the scheduled repayment dates.

There have been no other material changes in the nine months ended September 30, 2013 to the Company's business and operational risks as described in the Company's December 31, 2012 MD&A.

Environmental Matters

The Company has recorded decommissioning provisions of $164 million as at September 30, 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 $56 million in future years and expects to use these credits to comply with applicable environmental regulations.

Critical Accounting Estimates and Accounting Judgments

The preparation of the Company's consolidated financial statements in accordance with GAAP requires that management makes 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 judgments in making these estimates and assumptions.

Effective January 1, 2013, the Company revised the estimated useful lives of its coal plants corresponding to the revised Canadian Federal government regulations for coal plants. On an overall basis, the impact was to reduce depreciation expense.

There have been no other significant changes to the Company's critical accounting estimates and accounting judgments as described in the Company's December 31, 2012 MD&A.

Accounting Changes

Effective January 1, 2013

The Company adopted a number of new accounting standards, together with the consequential amendments to other International Financial Reporting Standards (IFRS). These standards, along with the impacts of the changes to the Company's financial statements, are as follows:

International Accounting Standard (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 was amended to present items within other comprehensive income on this basis.

IFRS 7 *Financial Instruments: Disclosures*

The amendments to IFRS 7 establish enhanced 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 resulted in additional disclosures regarding the offsetting of financial assets and financial liabilities.

IFRS 10 *Consolidated Financial Statements*

The adoption of IFRS 10 did not result in the consolidation of new subsidiaries or other entities that were not previously consolidated or a change in the treatment of subsidiaries that were previously consolidated.

IFRS 11 *Joint Arrangements*

The adoption of IFRS 11 did not change the accounting for any of the Company's joint arrangements as the previous treatment applied by the Company was aligned with the new standard.

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 will result in additional financial statement disclosures relating to interests in subsidiaries and joint arrangements in the Company's annual financial statements for 2013.

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 including the requirement to include such disclosures within the notes to the Company's condensed interim consolidated financial statements.

Future

IAS 32 *Financial Instruments: Presentation*

In December 2011, the IASB issued amendments to IAS 32 that clarify the criteria for offsetting financial assets and financial liabilities. Capital Power does not expect that the adoption of the amendments will have a material effect on the consolidated financial statements since the Company's current accounting policies are substantially aligned with the amendments. The amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, and are to be applied retrospectively. Earlier application is permitted.

IFRS 9 *Financial Instruments*

The IASB is conducting a multi-phase replacement of IAS 39 Financial Instruments: Recognition and Measurement with IFRS 9 Financial Instruments. The objectives of this project are to: (1) reduce complexity and improve comparability by limiting the number of categories into which financial assets and financial liabilities may be classified, (2) improve amortized cost measurement of financial assets, and (3) improve the usefulness of financial statements for users by fundamentally reconsidering the current hedge accounting requirements. The specific impacts to Capital Power will be determined as the various phases of the replacement project are finalized and issued in the revised standard. On a tentative basis, the proposed changes will be effective for annual periods beginning on or after January 1, 2015 and are to be applied retrospectively. Earlier application is expected to be permitted.

Financial Instruments

The classification, carrying amounts and fair values of financial instruments held at September 30, 2013 and December 31, 2012 were as follows:

($millions)			As at			
			September 30, 2013		December 31, 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	31	31	53	53
Trade and other receivables	Loans and receivables	n/a	250	250	354	354
Derivative financial instruments assets – current and non-current	Financial assets designated at fair value through income or loss	See below	72	72	77	77
Finance lease receivables	Loans and receivables	Level 2	445	344	461	374
Other financial assets	Loans and receivables	Level 2	55	55	55	55
Financial liabilities:						
Trade and other payables	Other financial liabilities	n/a	208	208	210	210
Derivative financial instruments liabilities – current and non-current	Financial liabilities designated at fair value through income or loss	See below	61	61	64	64
Loans and borrowings (including current portion)	Other financial liabilities	Level 2	2,063	2,129	1,659	1,736

Risk management and hedging activities

There have been no material changes in the nine months ended September 30, 2013 to the Company's risk management and hedging activities as described in the Company's December 31, 2012 MD&A.

The derivative instruments assets and liabilities held at September 30, 2013 compared with December 31, 2012 and used for risk management purposes were measured at fair value and consisted of the following:

($millions)		As at September 30, 2013				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange non-hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 1	-	2	-	-	2
	Level 2	41	27	-	1	69
	Level 3		1	-	-	1
		41	30	-	1	72
Derivative financial instruments liabilities	Level 1	-	-	-	-	-
	Level 2	(26)	(31)	(1)	-	(58)
	Level 3	-	(3)	-	-	(3)
		(26)	(34)	(1)	-	(61)
Net derivative financial instruments assets (liabilities)		**15**	**(4)**	**(1)**	**1**	**11**

($millions)		As at December 31, 2012				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange non-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 derivatives designated as accounting hedges

As at September 30, 2013, the fair value of the commodity derivatives designated and qualifying for hedge accounting was a net asset of $15 million, a decrease from the net asset of $29 million at December 31, 2012. Unrealized gains and losses for fair value changes on commodity derivatives that qualify for hedge accounting are recorded in other comprehensive income and reclassified to net income as revenues or energy purchases and fuel, as appropriate, when realized.

Derivatives not designated as accounting hedges

As at September 30, 2013, the fair value of commodity derivatives not designated as hedges for accounting purposes was a net liability of $4 million compared with a net liability of $16 million at December 31, 2012. The difference primarily reflected the impact of changes in the 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 revenues or energy purchases and fuel, as appropriate.

As at September 30, 2013, the Company's foreign exchange and interest rate derivative contracts were entered into to manage foreign exchange and interest rate risks relating to the sale of the North East U.S. assets. As at December 31, 2012, the Company did not have any forward foreign currency contracts outstanding. Unrealized and realized losses on foreign exchange derivatives that are not designated as hedges for accounting purposes are recorded in energy revenues or foreign exchange gains and losses.

Level 3 financial assets and liabilities

The determination of fair value 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 September 30, 2013 and December 31, 2012 reflected negligible differences compared with their recorded fair values.

Disclosure Controls and Procedures and Internal Control over Financial Reporting

During the nine months ended September 30, 2013, the Company implemented a new Enterprise Resource Planning (ERP) system to provide enhanced financial and other information that will support its strategic plans and business operations. The implementation of the ERP system has 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 will be tested and evaluated as the implementation is completed and, in full, prior to the Company's December 31, 2013 year-end.

There were no other changes in the Company's disclosure controls and procedures and internal controls over financial reporting that occurred during the nine months ended September 30, 2013 that have materially affected or are reasonably likely to materially affect the Company's disclosures of required information and internal control over financial reporting.

Summary of Quarterly Results

(GWh)	Three months ended							
Electricity generation	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**
Total generation excluding acquired Sundance PPA and CPILP plants	4,317	3,746	4,142	4,159	4,575	3,499	4,222	3,780
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	480	493	481	272	507	453	399	222
Keephills 3	483	296	457	484	489	473	430	485
Clover Bar Energy Centre 1, 2 and 3	45	157	85	174	130	140	27	132
Joffre	109	109	101	65	87	97	92	104
Halkirk	76	118	135	44	n/a	n/a	n/a	n/a
Taylor Coulee Chute	n/a	n/a	n/a	n/a	n/a	n/a	n/a	2
Clover Bar Landfill Gas	4	4	3	7	8	9	8	7
Alberta commercial plants – owned	1,197	1,177	1,262	1,046	1,221	1,172	956	952
Acquired Sundance PPA	659	712	691	517	738	660	695	596
	1,856	1,889	1,953	1,563	1,959	1,832	1,651	1,548
Alberta contracted plants								
Genesee 1	819	482	807	830	755	767	814	855
Genesee 2	840	704	788	767	815	589	843	849
	1,659	1,186	1,595	1,597	1,570	1,356	1,657	1,704
Ontario and British Columbia contracted plants								
Island Generation	14	-	-	3	8	-	66	1
Kingsbridge 1	12	22	37	35	15	22	37	35
Quality Wind	68	88	108	70	n/a	n/a	n/a	n/a
Brown Lake	n/a	n/a	n/a	2	14	16	15	14
Miller Creek	n/a	n/a	n/a	1	22	16	4	8
	94	110	145	111	59	54	122	58
North East U.S. commercial plants								
Bridgeport	690	678	913	863	905	300	844	499
Rumford	57	32	25	15	229	87	33	83
Tiverton	434	409	55	389	416	354	452	389
	1,181	1,119	993	1,267	1,550	741	1,329	971
North Carolina U.S. contracted plants								
Roxboro	69	57	53	50	64	61	55	36
Southport	117	97	94	88	111	115	103	59
	186	154	147	138	175	176	158	95
CPILP plants	n/a	n/a	n/a	n/a	n/a	n/a	n/a	427

(%)	Three months ended							
Plant availability	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**
Total average plant availability excluding acquired Sundance PPA and CPILP plants	97	86	94	89	97	81	97	87
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	99	100	98	56	100	95	84	44
Keephills 3	100	65	98	100	100	100	95	99
Clover Bar Energy Centre 1, 2 and 3	93	99	99	98	97	97	98	99
Joffre	100	100	92	65	98	99	94	93
Halkirk	89	99	98	95	n/a	n/a	n/a	n/a
Taylor Coulee Chute	n/a	n/a	n/a	n/a	n/a	n/a	n/a	100
Clover Bar Landfill Gas	66	91	97	92	92	86	95	77
Alberta commercial plants – owned	96	92	97	81	99	98	93	84
Acquired Sundance PPA	83	93	97	74	97	90	95	81
	90	92	97	79	98	96	93	83
Alberta contracted plants								
Genesee 1	98	61	96	98	93	97	97	100
Genesee 2	100	86	94	94	99	72	100	100
	99	74	95	96	96	85	98	100
Ontario and British Columbia contracted plants								
Island Generation	100	100	100	100	100	100	100	100
Kingsbridge 1	95	96	99	100	99	99	99	98
Quality Wind	100	98	99	99	n/a	n/a	n/a	n/a
Brown Lake	n/a	n/a	n/a	100	99	100	99	93
Miller Creek	n/a	n/a	n/a	85	71	38	85	78
	99	99	99	100	97	94	98	98
North East U.S. commercial plants								
Bridgeport	93	83	97	85	95	35	96	59
Rumford	100	77	97	84	97	84	98	94
Tiverton	96	93	51	89	99	77	100	89
	95	84	86	86	97	58	98	76
North Carolina U.S. contracted plants								
Roxboro	97	88	94	89	97	84	96	100
Southport	99	94	96	90	100	87	96	100
	98	92	96	90	99	86	96	100
CPILP plants	n/a	n/a	n/a	n/a	n/a	n/a	n/a	96

Financial results

(unaudited, $ millions)	Three months ended							
	Sep 30 2013	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**
Revenues and other income								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	186	182	150	144	206	140	179	167
Alberta contracted plants	80	27	69	75	69	63	75	86
Ontario and British Columbia contracted plants	16	18	25	18	12	12	14	13
North East U.S. commercial plants and portfolio optimization	63	63	78	65	62	34	59	51
North Carolina U.S. contracted plants	20	17	15	16	19	18	18	14
CPILP plants	n/a	n/a	n/a	n/a	n/a	n/a	n/a	51
Other portfolio activities	16	16	19	12	8	2	12	18
Corporate	1	3	-	1	1	4	6	1
Interplant category transaction eliminations	(5)	(1)	(2)	(1)	(1)	(1)	(1)	(3)
	377	325	354	330	376	272	362	398
Unrealized changes in fair value of CPLP's energy derivative instruments and Atlantic Power shares	3	(4)	11	(34)	18	(11)	14	-
Unrealized changes in fair value of CPILP's foreign exchange contracts	n/a	n/a	n/a	n/a	n/a	n/a	n/a	9
	3	(4)	11	(34)	18	(11)	14	9
	380	**321**	**365**	**296**	**394**	**261**	**376**	**407**
Adjusted EBITDA								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	105	114	81	64	113	55	87	70
Alberta contracted plants	55	7	44	51	38	35	45	51
Ontario and British Columbia contracted plants	9	12	20	15	8	9	10	10
North East U.S. commercial plants and portfolio optimization	11	7	4	(1)	12	1	13	6
North Carolina U.S. contracted plant	2	1	1	2	-	-	2	4
CPILP plants	n/a	n/a	n/a	n/a	n/a	n/a	n/a	19
Other portfolio activities	(1)	(2)	(2)	(1)	4	-	7	6
Corporate	(31)	(30)	(26)	(30)	(31)	(27)	(25)	(26)
Interplant category transaction eliminations	-	-	-	-	-	-	-	-
	150	109	122	100	144	73	139	140
Unrealized changes in fair value of CPLP's energy derivative instruments and Atlantic Power shares	1	(5)	13	(27)	7	(8)	13	-
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	n/a	n/a	n/a	n/a	n/a	n/a	n/a	10
	1	(5)	13	(27)	7	(8)	13	10
	151	**104**	**135**	**73**	**151**	**65**	**152**	**150**

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 as well as items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's derivative 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							
	Sep 30 2013	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**
Revenues and other income	380	321	365	296	394	261	376	407
Adjusted EBITDA[(1)]	151	104	135	73	151	65	152	150
Net income (loss)	59	23	48	19	63	(58)	66	152
Net income (loss) attributable to shareholders of the Company	44	20	34	15	39	(32)	40	84
Basic earnings (loss) per share ($)	0.55	0.20	0.44	0.19	0.55	(0.50)	0.66	1.47
Normalized earnings per share ($) [1]	0.72	0.27	0.36	0.23	0.55	0.07	0.46	0.36

[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	**Sep 30 2013**	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**
Alberta power ($/MWh)	84	123	65	79	78	40	60	76
New England mass hub (US$/MWh)	42	40	86	45	37	29	33	38
Alberta natural gas (AECO) ($/Gj)	2.32	3.36	3.03	2.16	2.16	1.80	2.06	3.03
Capital Power's Alberta portfolio average realized power price ($/MWh)	94	93	69	65	81	60	83	75

Factors impacting results for the previous quarters

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

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 energy 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.

In the fourth quarter of 2011, the Company sold its limited partnership units of CPILP to Atlantic Power effective November 5, 2011 resulting in the recognition of a pre-tax gain on disposal of $89 million after deducting legal and other disposal costs of $10 million. From that point forward, the Company's operations and corporate structure were simplified as there was a decrease in the number of plants and legal entities and CPILP's results were no longer consolidated with the Company's results. Absent other changes, the disposal decreased revenues, net income and net income attributable to non-controlling interests for the fourth quarter of 2011 and future quarters relative to past quarters. Capital Power's Genesee 3 plant experienced an unplanned outage which reduced its generation volumes but this was partly offset by increased generation from the Company's CBEC facility. This and other Alberta portfolio optimization activities given the higher power prices experienced due to plant outages and higher demand helped offset a portion of the loss of earnings from Genesee 3 being offline.

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							
	Sep 30 2013	**Jun 30 2013**	**Mar 31 2013**	**Dec 31 2012**	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**
Share price ($/common share)								
High	22.22	22.55	23.53	23.20	24.53	24.47	25.72	25.78
Low	19.80	19.76	21.02	20.88	20.75	22.48	23.29	22.88
Close	21.26	20.58	21.20	22.73	21.29	23.78	23.49	25.12
Volume of shares traded (millions)	8.8	7.9	9.4	10.8	9.6	10.3	9.0	10.6

Outstanding share and partnership unit data

As at October 22, 2013, the Company had 80.551 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 and the outstanding special voting shares to common shares and ignoring exercise prices, the outstanding and issuable common shares as at October 22, 2013 were 103.862 million. All of the outstanding special voting shares and the outstanding special limited voting share are held by EPCOR.

As at October 22, 2013, 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.

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Financial Statements
Nine months ended September 30, 2013 and 2012

Condensed Interim Consolidated Financial Statements:

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Revenues	$ 372	$ 393	$ 1,044	$ 1,015
Other income	8	1	22	16
Energy purchases and fuel	(149)	(165)	(440)	(425)
Gross margin	231	229	626	606
Other raw materials and operating charges	(22)	(19)	(62)	(68)
Staff costs and employee benefits expense	(37)	(39)	(114)	(109)
Depreciation and amortization	(54)	(52)	(170)	(159)
Impairments (notes 4 and 6)	(6)	-	(6)	(74)
Other administrative expenses	(21)	(20)	(60)	(61)
Foreign exchange loss	(1)	-	(1)	-
Operating income	90	99	213	135
Finance expense	(18)	(18)	(60)	(54)
Income before tax	72	81	153	81
Income tax expense (note 5)	(13)	(18)	(23)	(10)
Net income	$ 59	$ 63	$ 130	$ 71
Attributable to:				
Non-controlling interests	$ 15	$ 24	$ 32	$ 24
Shareholders of the Company	$ 44	$ 39	$ 98	$ 47
Earnings per share (attributable to common shareholders of the Company):				
Basic (note 7)	$ 0.55	$ 0.55	$ 1.19	$ 0.65
Diluted (note 7)	$ 0.51	$ 0.55	$ 1.14	$ 0.63

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Net income	$ 59	$ 63	$ 130	$ 71
Other comprehensive (loss) income:				
Items that will not be reclassified subsequently to net income:				
Defined benefit plans:				
Actuarial losses[1]	-	-	-	(3)
Items that are or may be reclassified subsequently to net income:				
Cash flow hedges:				
Unrealized gains (losses) on derivative instruments[2]	-	31	(65)	68
Reclassification of losses (gains) on derivative instruments to income for the period[3]	2	3	41	(22)
Net investment in foreign subsidiaries:				
Unrealized (loss) gain[4]	(9)	(15)	14	(15)
Total items that are or may be reclassified subsequently to net income	(7)	19	(10)	31
Total other comprehensive (loss) income, net of tax	(7)	19	(10)	28
Total comprehensive income	$ 52	$ 82	$ 120	$ 99
Attributable to:				
Non-controlling interests	$ 13	$ 32	$ 28	$ 37
Shareholders of the Company	$ 39	$ 50	$ 92	$ 62

[1] For the three and nine months ended September 30, 2013, net of income tax recoveries of nil. For the three and nine months ended September 30, 2012, net of income tax recoveries of nil and $1 respectively.

[2] For the three and nine months ended September 30, 2013, net of income tax recoveries of nil and $14 respectively. For the three and nine months ended September 30, 2012, net of income tax expenses of $6 and $14 respectively.

[3] For the three and nine months ended September 30, 2013, net of reclassification of income tax recoveries of $1 and $9 respectively. For the three and nine months ended September 30, 2012, net of reclassification of income tax recoveries of $1 and reclassification of income tax expenses of $4 respectively.

[4] For the three and nine months ended September 30, 2013 and September 30, 2012, net of income tax expenses of nil.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	September 30, 2013	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$ 31	$ 53
Trade and other receivables	250	354
Inventories	68	72
Derivative financial instruments assets (note 8)	41	47
Assets held for sale (note 6)	609	-
	999	526
Non-current assets:		
Other assets	24	21
Derivative financial instruments assets (note 8)	31	30
Finance lease receivables	445	461
Other financial assets	72	60
Deferred tax assets	101	70
Intangible assets	345	316
Property, plant and equipment	3,776	3,628
Goodwill	22	22
Total assets	$ 5,815	$ 5,134
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 208	$ 210
Derivative financial instruments liabilities (note 8)	48	52
Loans and borrowings	13	19
Deferred revenue and other liabilities	5	8
Provisions	25	24
Liabilities related to assets held for sale (note 6)	68	-
	367	313
Non-current liabilities:		
Derivative financial instruments liabilities (note 8)	13	12
Loans and borrowings	2,050	1,640
Deferred revenue and other liabilities	90	91
Deferred tax liabilities	146	112
Provisions	162	214
	2,461	2,069
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 9)	2,119	1,903
Retained earnings (deficit)	16	(1)
Other reserves	16	21
Retained earnings (deficit) and other reserves	32	20
	2,151	1,923
Non-controlling interests	836	829
Total equity	2,987	2,752
Subsequent event (note 13)		
Total liabilities and equity	$ 5,815	$ 5,134

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share capital	Cash flow hedges[1]	Cumulative translation account[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2013	$ 1,903	$ 15	$ 10	$ (13)	$ 9	$ (1)	$ 1,923	$ 829	$ 2,752
Net income	-	-	-	-	-	98	98	32	130
Other comprehensive (loss) income :									
Cash flow derivative hedge losses	-	(79)	-	-	-	-	(79)	-	(79)
Reclassification of losses to income	-	50	-	-	-	-	50	-	50
Unrealized gain on foreign currency translation	-	-	14	-	-	-	14	-	14
Tax on items recognized directly in equity	-	5	-	-	-	-	5	-	5
Attributed to non-controlling interests	-	8	(4)	-	-	-	4	(4)	-
Other comprehensive (loss) income	$ -	$ (16)	$ 10	$ -	$ -	$ -	$ (6)	$ (4)	$ (10)
Total comprehensive (loss) income	-	(16)	10	-	-	98	92	28	120
Issue of share capital (note 9)	200	-	-	-	-	-	200	-	200
Share issue costs (note 9)	(6)	-	-	-	-	-	(6)	-	(6)
Deferred taxes (note 9)	2	-	-	-	-	-	2	-	2
Distributions to non-controlling interests	-	-	-	-	-	-	-	(27)	(27)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	6	6
Common share dividends (note 9)	-	-	-	-	-	(67)	(67)	-	(67)
Preferred share dividends (note 9)	-	-	-	-	-	(14)	(14)	-	(14)
Dividends reinvested (note 9)	20	-	-	-	-	-	20	-	20
Share-based compensation	-	-	-	-	1	-	1	-	1
Equity as at September 30, 2013	$ 2,119	$ (1)	$ 20	$ (13)	$ 10	$ 16	$ 2,151	$ 836	$ 2,987

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

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share capital	Cash flow hedges[1]	Cumulative translation account[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Retained earnings	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2012	$ 1,499	$ (10)	$ 17	$ (7)	$ 8	$ 16	$ 1,523	$ 1,072	$ 2,595
Net income	-	-	-	-	-	47	47	24	71
Other comprehensive income (loss):									
Defined benefit plan actuarial losses	-	-	-	(4)	-	-	(4)	-	(4)
Cash flow derivative hedge gains	-	82	-	-	-	-	82	-	82
Reclassification of gains to income	-	(26)	-	-	-	-	(26)	-	(26)
Unrealized loss on foreign currency translation	-	-	(15)	-	-	-	(15)	-	(15)
Tax on items recognized directly in equity	-	(10)	-	1	-	-	(9)	-	(9)
Attributed to non-controlling interests	-	(18)	5	-	-	-	(13)	13	-
Other comprehensive income (loss)	$ -	$ 28	$ (10)	$ (3)	$ -	$ -	$ 15	$ 13	$ 28
Total comprehensive income (loss)	-	28	(10)	(3)	-	47	62	37	99
Issue of share capital	239	-	-	-	(1)	11	249	(252)	(3)
Distributions to non-controlling interests	-	-	-	-	-	-	-	(30)	(30)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	6	6
Common share dividends (note 9)	-	-	-	-	-	(62)	(62)	-	(62)
Preferred share dividends (note 9)	-	-	-	-	-	(4)	(4)	-	(4)
Dividends reinvested (note 9)	12	-	-	-	-	-	12	-	12
Share-based compensation	-	-	-	-	2	-	2	-	2
Equity as at September 30, 2012	$ 1,750	$ 18	$ 7	$ (10)	$ 9	$ 8	$ 1,782	$ 833	$ 2,615

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

CAPITAL POWER CORPORATION

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

	Nine months ended September 30, 2013	2012
Cash flows from operating activities:		
Net income	$ 130	$ 71
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	170	159
Impairments (note 6)	6	74
Finance expense	60	54
Fair value changes on derivative instruments	(9)	(25)
Income tax expense	23	10
Other items	(21)	7
Interest paid[1]	(49)	(37)
Income taxes paid	(5)	(6)
Change in non-cash operating working capital	35	(94)
Net cash flows from operating activities	340	213
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(884)	(433)
Proceeds on disposal of assets	-	52
Other cash flows from investing activities	36	31
Net cash flows used in investing activities	(848)	(350)
Cash flows from financing activities:		
Proceeds from issue of loans and borrowings	410	250
Repayment of loans and borrowings	(18)	(52)
Issue costs on loans and borrowings	(1)	(3)
Proceeds from issue of common shares	-	8
Proceeds from issue of preferred shares (note 9)	200	-
Share issue costs (note 9)	(6)	-
Distributions paid to non-controlling interests	(27)	(33)
Common share dividends paid (note 9)	(46)	(47)
Preferred share dividends paid (note 9)	(14)	(4)
Interest paid[1]	(13)	(19)
Net cash flows from financing activities	485	100
Foreign exchange gains (losses) on cash held in a foreign currency	1	(1)
Net decrease in cash and cash equivalents	(22)	(38)
Cash and cash equivalents at beginning of period	53	73
Cash and cash equivalents at end of period	$ 31	$ 35

[1] Total interest paid.

See accompanying notes to the condensed interim consolidated financial statements

1. Reporting entity:

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

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

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

2. Basis of presentation:

These condensed interim consolidated financial statements have been prepared by Management in accordance with International Accounting Standards (IAS) 34, Interim Financial Reporting. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements and should be read in conjunction with the Company’s 2012 annual financial statements prepared in accordance with International Financial Reporting Standards (IFRS).

These condensed interim consolidated financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent consolidated financial statements for the year ended December 31, 2012, except as described in note 3, and have been prepared under the historical cost basis, except for the Company’s derivative instruments, defined benefit pension assets and cash-settled share based payments, which are stated at fair value.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on October 25, 2013.

3. Changes in accounting policies:

Effective January 1, 2013, the Company has 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 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 to present items within other comprehensive income on this basis.

IFRS 7 – Financial Instruments: Disclosures – The amendments to IFRS 7 establish enhanced 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 10.

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 will result in additional financial statement disclosures relating to interests in subsidiaries and joint arrangements in the Company’s annual financial statements for 2013.

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 10, including the requirement to include such disclosures within the notes to the Company’s interim consolidated financial statements.

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

3. Changes in accounting policies, continued:

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

- IFRS 10 – Consolidated Financial Statements – The adoption of IFRS 10 did not result in the consolidation of new subsidiaries or other entities that were not previously consolidated or a change in the treatment to subsidiaries that were previously consolidated.
- IFRS 11 – Joint Arrangements – The adoption of IFRS 11 did not change the accounting for any of the Company's joint arrangements as the previous treatment applied by the Company was aligned with the new standard.
- IAS 19 – Employee Benefits
- International Financial Reporting Standards Interpretations Committee (IFRIC) 20 – Stripping Costs in the Production Phase of a Surface Mine

4. Impairment testing:

The Company reviews its cash generating units (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.

In addition to the annual testing noted above, the Company tested its North East U.S. CGU for impairment, immediately prior to classifying those assets as assets held for sale, as described in note 6.

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 sale agreement described in note 6, 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 10.

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 10, 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 ranged 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 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%

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

4. Impairment testing, continued:

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.

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.

5. Income tax:

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

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Income before tax	$ 72	$ 81	$ 153	$ 81
Income tax at the statutory rates of 25.0%	18	20	38	20
Increase (decrease) resulting from:				
Amounts attributable to non-controlling interests	(4)	(2)	(8)	(7)
Non-deductible (taxable) amounts	(1)	(2)	(4)	7
Statutory and other rate differences	(3)	-	(6)	(13)
Change in unrecognized tax benefits	3	-	3	-
Prior period tax adjustments	-	2	-	2
Other	-	-	-	1
Income tax expense	$ 13	$ 18	$ 23	$ 10

6. Assets held for sale:

In August 2013, the Company entered into an agreement with a third party, pursuant to which the third party will acquire one hundred percent of Capital Power's equity interests in Bridgeport Energy, LLC, Tiverton Power, LLC, and Rumford Power Inc. for base cash proceeds of US$541 million, subject to working capital adjustments. These entities own Capital Power's Bridgeport, Tiverton and Rumford (North East U.S. CGU) generation facilities. The transaction is expected to close in the fourth quarter of 2013, subject to regulatory approvals and customary closing conditions.

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

6. Assets held for sale, continued:

At September 30, 2013, the disposal group consisted of assets and liabilities as follows:

	September 30, 2013
Assets held for sale	
Trade and other receivables	$ 5
Inventories	9
Intangible assets	14
Property, plant and equipment	581
	$ 609
Liabilities related to assets held for sale	
Trade and other payables	$ 10
Derivative financial instruments liabilities – current and non-current	3
Deferred tax liabilities	18
Provisions – non-current	37
	$ 68

Immediately before the classification of the above assets and liabilities as held for sale, based on the sales proceeds to be received compared to the associated carrying amounts, the Company determined that it was necessary to test the North East U.S. CGU, for impairment. As a result, the Company recorded pre-tax impairments of $6 million within the U.S. geographic area as a reduction to the carrying amount of the property, plant and equipment of the North East U.S. CGU.

For purposes of calculating the above impairments, the Company used the fair value less costs to sell of the CGU as the recoverable amount of the assets. The fair value less costs to sell was established by the proceeds set out in the sale agreement described above, less the Company's estimate of the directly attributable incremental costs related to the disposal.

Following the impairment recorded above, the fair value less costs to sell equaled the carrying amount of the assets and liabilities to be sold and as such no further adjustments were required upon initial classification as assets and liabilities held for sale.

As at September 30, 2013, accumulated other comprehensive income, recorded within other reserves within the consolidated statement of financial position, included accumulated foreign currency translation gains of $51 million relating to the Company's North East U.S. net assets. These foreign currency translation gains were previously recognized directly in accumulated other comprehensive income and will be reclassified to net income, within the gain on disposal, upon transaction close. These amounts are subject to changes in foreign exchange rates between September 30, 2013 and the close of the transaction.

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

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:

	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Income for the period attributable to shareholders of the Company	$ 44	$ 39	$ 98	$ 47
Preferred share dividends of the Company [1]	(5)	(1)	(14)	(4)
Earnings used in the calculation of basic earnings per share	$ 39	$ 38	$ 84	$ 43

[1] Includes preferred share dividends in respect of the three and nine months ended September 30, 2013 and 2012 respectively.

	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Weighted average number of common shares used in the calculation of basic earnings per share	70,828,245	69,516,691	70,488,590	65,802,931

Diluted earnings per share

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

	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
Earnings used in the calculation of basic earnings per share	$ 39	$ 38	$ 84	$ 43
Effect of exchangeable limited partnership units issued to EPCOR for common shares [2]	12	-	29	19
Earnings used in the calculation of diluted earnings per share	$ 51	$ 38	$ 113	$ 62

[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 three and nine months ended September 30, 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 Capital Power L.P. (CPLP) of $17 million and $41 million for the three and nine months ended September 30, 2013 respectively. 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 $5 million and $12 million for the three and nine months ended September 30, 2013 respectively. For the nine months ended September 30, 2012, 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 $33 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 three months ended September 30, 2012 the potential exchange of such units for common shares of the Company were not included in the calculation of diluted earnings per share as they were anti-dilutive.

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

7. Earnings per share, continued:

Diluted earnings per share, continued

The weighted average number of common shares used in the calculation 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:

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Weighted average number of common shares used in the calculation of basic earnings per share	70,828,245	69,516,691	70,488,590	65,802,931
Effect of dilutive share purchase options[1]	-	-	-	3,257
Effect of exchangeable limited partnership units issued to EPCOR for common shares	28,441,000	-	28,441,000	31,865,818
Weighted average number of common shares used in the calculation of diluted earnings per share	99,269,245	69,516,691	98,929,590	97,672,006

[1] For the three and nine months ended September 30, 2013 and the three months ended September 30, 2012, the average market price of the Company's common shares was below the exercise price of all granted share purchase options and as a result none of the share purchase options had a dilutive effect on earnings per share. For the nine months ended September 30, 2012, the average market price of the Company's common shares exceeded the exercise price of certain of the granted share purchase options and as a result had a dilutive effect on earnings per share.

8. Derivative financial instruments and hedge accounting:

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

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

	September 30, 2013				
	Energy		Foreign exchange	Interest rate	
	cash flow hedges	non-hedges	non-hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 22	$ 18	$ -	$ 1	$ 41
Non-current	19	12	-	-	31
Derivative instruments liabilities:					
Current	(19)	(28)	(1)	-	(48)
Non-current	(7)	(6)	-	-	(13)
Net fair value	$ 15	$ (4)	$ (1)	$ 1	$ 11
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(10)	(3)	-	-	
Gigajoules of natural gas (millions)	-	1	-	-	
Foreign exchange options and interest rate swaps (millions of U.S. dollars)	-	-	$ 484	$ 100	
Range of remaining contract terms in years	0.1 to 4.3	0.1 to 5.3	0.1 to 0.4	7.7	

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

8. Derivative financial instruments and hedge accounting, continued:

	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	

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 inputs, 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:

	Three months ended September 30, 2013		Three months ended September 30, 2012	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains	Realized losses
Energy cash flow hedges	$ 3	$ (3)	$ 41	$ (4)
Energy non-hedges	1	29	7	(3)
Foreign exchange non-hedges	(1)	-	-	-
Interest rate non-hedges	1	-	-	-

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

8. Derivative financial instruments and hedge accounting, continued:

	Nine months ended September 30, 2013		Nine months ended September 30, 2012	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains	Realized gains (losses)
Energy cash flow hedges	$ (29)	$ (50)	$ 56	$ 26
Energy non-hedges	9	104	17	31
Foreign exchange non-hedges	(1)	-	-	-
Interest rate non-hedges	1	-	8	(7)

Realized gains and losses relate only to financial derivative instruments. The following gains and (losses) are included in the Company's statements of income for the three and nine months ended September 30, 2013 and 2012:

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Revenues	$ 57	$ 11	$ 115	$ 99
Energy purchases and fuel	(30)	(11)	(52)	(25)
Foreign exchange losses	(1)	-	(1)	-
Finance expense	1	-	1	1

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. For the three and nine months ended September 30, 2013, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statements of income were nil (three and nine months ended September 30, 2012 – nil).

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

	September 30, 2013
Within one year	$ (11)
Between 1 – 5 years	9
After more than 5 years	-
	$ (2)

The Company's cash flow hedges extend up to 2018.

9. Share capital:

On April 26, 2013, the Company's shareholders adopted a Shareholder Rights Plan (Rights Plan). The Rights Plan expires at the end of the annual meeting of shareholders in 2016. Under the Rights Plan, one right is issued with each issued voting share of the Company. The rights remain attached to the shares and can only be exercised or detached when certain events as specified under the Rights Plan occur. The rights provided under the Rights Plan are not triggered by any person making Share Acquisitions or Redemptions, Permitted Bid Acquisitions, Exempt Acquisitions, Convertible Security Acquisitions or Pro Rata Acquisitions, unless certain conditions are met as defined in the Rights Plan.

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

9. Share capital, continued:

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.

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 common and preferred share dividends declared and paid by the Company for the three and nine months ended September 30, 2013 are summarized as follows:

	Dividends declared							
	For the three months ended September 30,				For the nine months ended September 30,			
	2013		2012		2013		2012	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common	$ 0.3150	$ 23	$ 0.3150	$ 22	$ 0.9450	$ 67	$ 0.9450	$ 62
Preference, Series 1	0.2875	1	0.2875	1	0.8625	4	0.8625	4
Preference, Series 3	0.2875	2	-	-	0.8901	6	-	-
Preference, Series 5	0.2813	2	-	-	0.6142	4	-	-

	Dividends paid							
	For the three months ended September 30,				For the nine months ended September 30,			
	2013		2012		2013		2012	
	Per share	Total[1]	Per share	Total[1]	Per share	Total[1]	Per share	Total[1]
Common	$ 0.3150	$ 22	$ 0.3150	$ 22	$ 0.9450	$ 66	$ 0.9450	$ 59
Preference, Series 1	0.2875	1	0.2875	1	0.8625	4	0.8625	4
Preference, Series 3	0.2875	2	-	-	0.8901	6	-	-
Preference, Series 5	0.2813	2	-	-	0.6142	4	-	-

[1] For the three and nine months ended September 30, 2013, dividends paid on common shares consist of $15 million and $46 million paid in cash and $7 million and $20 million paid through the Company's dividend reinvestment plan as common shares issued, respectively. For the three and nine months ended September 30, 2012, dividends paid on common shares consist of $15 million and $47 million paid in cash and $7 million and $12 million paid through the Company's dividend reinvestment plan as common shares issued, respectively.

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

10. Financial instruments:

Fair values

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

The 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 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.

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

		September 30, 2013		December 31, 2012	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets					
Loans and receivables	Level 2	$ 55	$ 55	$ 55	$ 55
Finance lease receivables					
Loans and receivables	Level 2	445	344	461	374
Loans and borrowings					
Other financial liabilities					
(includes current portion)	Level 2	2,063	2,129	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 September 30, 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 September 30, 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 statements of financial position are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The 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.

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

10. Financial instruments, continued:

Fair value hierarchy, continued

- 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 the discounted cash flow model or the Black-Scholes option pricing models. 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 may 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.
- 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 may 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 statements of financial position, classified using the fair value hierarchy described above:

	September 30, 2013			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets				
Commodity derivatives	$ 2	$ 68	$ 1	$ 71
Interest rate derivatives	-	1	-	1
	$ 2	$ 69	$ 1	$ 72
Derivative financial instruments liabilities				
Commodity derivatives	-	(57)	(3)	(60)
Foreign exchange derivatives	-	(1)	-	(1)
	$ -	$ (58)	$ (3)	$ (61)

	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)

10. Financial instruments, continued:

Fair value hierarchy, continued

The Company's policy is to recognize transfers between levels as of the date of the event of change in circumstances that caused the transfer. There were no significant transfers between levels in the fair value hierarchy for the three and nine months ended September 30, 2013 and the year ended December 31, 2012.

Valuation techniques used in determination of fair values within Levels 2 and 3

The fair values of the Company's commodity derivatives included within Levels 2 and 3 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.

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 applying the Black-Scholes option pricing model. The inputs used in these calculations include forward foreign exchange curves and volatility levels and are based on observable market data.

The key unobservable inputs used in the determination of the fair values of the Company's Level 3 commodity derivatives are volatilities and correlations of the relative price changes in underlying prices. The volatilities and correlations are estimated using an exponentially-weighted moving average calculated on historical forward prices. The range of volatilities used is 0.14 to 0.31 and 0.15 to 1.53 as at September 30, 2013 and December 31, 2012, respectively. The range of correlations between gas and power points is 0.28 to 0.74 and (0.03) to 0.85 as at September 30, 2013 and December 31, 2012, respectively.

Valuation process applied to Level 3

The calculations of the fair value of derivative financial instruments assets and liabilities within level 3 are performed by the Company's commodity risk group and reviewed by management. The valuation technique and the associated inputs are assessed on a regular basis for ongoing reasonability.

For the significant financial instruments, the Company performs a sensitivity analysis for fair value measurements classified as Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions, if available, to the valuation models. The sensitivity analyses for the periods ended September 30, 2013 and December 31, 2012 reflected negligible differences compared with the fair value used to record financial instruments classified in Level 3.

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

10. Financial instruments, continued:

Fair value hierarchy, continued

Continuity of level 3 balances

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

	Nine months ended September 30, 2013	Year ended December 31, 2012
As at January 1 [1]	$ (16)	$ (1)
Unrealized and realized gains (losses) included in net income [2]	2	(23)
Settlements [3]	12	8
As at end of period	$ (2)	$ (16)
Total unrealized gains (losses) for the period included in net income	$ 15	$ (15)

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

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

[3] Relates to settlement of financial derivative instruments.

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

Offsetting of financial assets and liabilities

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

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

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

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

10. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

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

As at September 30, 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	$ 212	$ (33)	$ 179	$ (41)	$ (4)	$ 134

[1] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $41 million, non-current derivative instruments assets of $31 million and trade and other receivables of $107 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 September 30, 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	$ 168	$ (33)	$ 135	$ (58)	$ (10)	$ 67

[3] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $48 million, non-current derivative instruments liabilities of $13 million and trade and other payables of $74 million. Current derivative instrument liabilities are net of $3 million classified as assets held for sale, as described in note 6.

[4] Collateral pledged against the net financial liabilities disclosed above is in the form of letters of credit issued.

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

10. 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.

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

11. Interest in joint arrangement:

During 2012, the Company entered into a series of agreements with a third party to purchase a 50% interest in the 800 megawatt Shepard Energy Centre (Shepard) in southern Alberta. 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 to the total anticipated capital cost of $860 million. Commencing upon close of the first tranche, all decisions related to Shepard require unanimous approval by the Company and the third party. As a result, the Company jointly controls Shepard with the third party 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.

12. 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. (Connecticut, Maine, North Carolina and Rhode Island), as this is how management assesses performance and determines resource allocations. The assets classified as held for sale, as described in note 6, operate within the U.S. (Connecticut, Maine and Rhode Island). Since the disposal of those assets will 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:

	Three months ended September 30, 2013				Three months ended September 30, 2012			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	$ 289	$ 91	$ -	$ 380	$ 307	$ 87	$ -	$ 394
Revenues and other income – inter-area [1]	11	-	(11)	-	8	6	(14)	-
Total revenues and other income	$ 300	$ 91	$ (11)	$ 380	$ 315	$ 93	$ (14)	$ 394

	Nine months ended September 30, 2013				Nine months ended September 30, 2012			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	$ 777	$ 289	$ -	$1,066	$ 779	$ 252	$ -	$1,031
Revenues and other income – inter-area [1]	29	(5)	(24)	-	14	8	(22)	-
Total revenues and other income	$ 806	$ 284	$ (24)	$1,066	$ 793	$ 260	$ (22)	$1,031

[1] The Company uses non-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. Gains or losses on such trades, including certain inter-area trades, are recognized on a net basis in the Company's revenues.

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

12. Segment information, continued:

	As at September 30, 2013			As at December 31, 2012		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,694	$ 82	$ 3,776	$ 2,947	$ 681	$ 3,628
Intangible assets	318	27	345	298	18	316
Goodwill	-	22	22	-	22	22
Other assets	24	-	24	21	-	21
	$ 4,036	$ 131	$ 4,167	$ 3,266	$ 721	$ 3,987

13. Subsequent event:

On October 10, 2013, a subsidiary of EPCOR exchanged 9,600,000 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 of Capital Power at an offering price of $21.00 per common share for gross proceeds of $202 million. As a result of the unit exchange and share offering, subsequent to the close of the third quarter of 2013, EPCOR's ownership interest in CPLP was reduced to approximately 19% (September 30, 2013 and December 31, 2012 – 29%). As of the release of these condensed interim consolidated financial statements, the underwriters maintain an over-allotment option to purchase up to an additional 1,440,000 common shares at $21.00 per common share, exercisable in whole or in part at any time up to 30 days after the closing date above.

As a result of EPCOR's ownership interest dropping below 20%, 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 September 30, 2013 was approximately $342 million. In addition, EPCOR may only elect two of Capital Power's directors as compared to four previously.

14. Comparative figures:

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