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Capital Power reports third quarter 2012 results and announces Quality Wind set to commence commercial operations

Strong operating and portfolio optimization performance leads to 28% increase in normalized earnings per share in the quarter

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released its financial results for the three and nine months ended September 30, 2012. The Company also announced that its Quality Wind project is set to commence commercial operations.

Financial results

Normalized earnings attributable to common shareholders in the third quarter of 2012, after adjusting for one-time items and fair value adjustments, were $38 million, or $0.55 per share, compared with $21 million, or $0.43 per share, in the comparable period of 2011.

"Third quarter financial performance was in line with our expectations," said Brian Vaasjo, President and CEO of Capital Power. "We saw an improvement in the Alberta spot power prices, which averaged $78 per megawatt hour (MWh) in the third quarter, compared to $50 per MWh in the first half of the year. The increase resulted in a record EBITDA contribution from the Alberta commercial plants and portfolio optimization segment. The third quarter was highlighted by strong operating performance across the fleet with average plant availability of 97 per cent."

"Should power prices in the fourth quarter remain consistent with third quarter levels, Capital Power remains on track to meet its revised 2012 annual financial targets," continued Mr. Vaasjo. "This includes normalized earnings per share that are expected to be slightly under the low end of the target range of $1.50 to $1.70 per share."

Funds from operations excluding non-controlling interests in CPILP were $128 million in the third quarter of 2012, up 10% from $116 million in the third quarter of 2011. Cash flow per share for the quarter was $1.31 compared with $1.21 for the same quarter in the previous year.

For the nine-month period ending September 30, 2012, normalized earnings attributable to common shareholders were $70 million or $1.06 per share compared with $35 million or $0.87 per share in the first nine months of 2011. Year-to-date funds from operations excluding non-controlling interests in CPILP totaled $298 million compared with $264 million in the nine-month period ending September 30, 2011.

Update on wind projects

The Company also provided an update on the status of its four wind projects. The 142-megawatt (MW) Quality Wind facility, located near Tumbler Ridge, British Columbia, is expected to begin commercial operations in early November 2012, which is on time and under budget. Final costs for the Quality Wind project are expected to be approximately 10 per cent below the $455 million budget.

"We've committed approximately $1.4 billion to four wind-power projects and the successful completion of Quality Wind marks another major milestone for Capital Power," said Brian Vaasjo. "The completion of the Quality Wind project on schedule and under budget reflects our growing expertise in the development and construction of wind-power facilities, which now represents a competitive advantage."

Quality Wind will be supplying renewable energy to British Columbia's electricity grid and comprises 79 Vestas wind turbines (V90 and V100 models), which will each produce 1.8 MWs of power. Power generated at Quality Wind will be sold to BC Hydro under a 25-year Energy Purchase Agreement. The facility has the capacity to generate enough power to meet the average annual needs of approximately 43,000 homes.

Capital Power is also using Vestas equipment at its 150-MW Halkirk Wind project in Alberta, which is also scheduled for completion in the fourth quarter of 2012, and at its 105-MW Port Dover & Nanticoke wind project in Ontario, which has commenced construction and is expected to be completed in the fourth quarter of 2013. The 270-MW K2 Wind Ontario project, a joint venture development with Samsung Renewable Energy Inc. and Pattern Renewable Holdings Canada, is expected to be completed in 2014.

By the end of 2012, Capital Power's wind-power capacity will be 332 MWs, from its Kingsbridge 1 facility in Ontario, Quality Wind in British Columbia, and Halkirk Wind in Alberta. By 2014, Capital Power's ownership in wind power capacity will grow to 527 MWs of renewable energy.

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)	**2012**	**2011**	**2012**	**2011**
Electricity generation (excluding acquired Sundance PPA and CPILP plants) (GWh)	4,575	4,221	12,296	9,879
Generation plant availability (excluding acquired Sundance PPA and CPILP plants) (%)	97%	97%	92%	94%
Revenues and other income	$ 394	$ 433	$ 1,035	$ 1,363
EBITDA[2]	$ 152	$ 139	$ 368	$ 335
Net income (loss) attributable to shareholders	$ 39	$ 15	$ 47	$ (7)
Earnings (loss) per share	$ 0.55	$ 0.29	$ 0.65	$ (0.27)
Diluted earnings (loss) per share	$ 0.55	$ 0.29	$ 0.63	$ (0.27)
Dividends declared per common share	$ 0.3150	$ 0.3150	$ 0.9450	$ 0.9450
Normalized earnings attributable to common shareholders[2]	$ 38	$ 21	$ 70	$ 35
Normalized earnings per share[2]	$ 0.55	$ 0.43	$ 1.06	$ 0.87
Funds from operations[2]	$ 128	$ 144	$ 298	$ 334
Funds from operations excluding non-controlling interests in CPILP[2]	$ 128	$ 116	$ 298	$ 264
Cash flow per share [2]	$ 1.31	$ 1.21	$ 3.05	$ 3.01
Dividend coverage ratio [2]	3.5	3.3	2.3	2.4
Capital expenditures	$ 150	$ 107	$ 433	$ 316

(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, 2012.

(2) Earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses, and gains on acquisitions and disposals (EBITDA), Funds from operations, Funds from operations excluding non-controlling interests in CPILP, Cash flow per share, Dividend coverage ratio, 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, therefore, may not be comparable to similar measures used by other enterprises. See Non-GAAP Financial Measures. Reconciliations of these non-GAAP financial measures to Net income attributable to shareholders, Earnings per share and Net cash flows from operating activities are included in the Company's Management's Discussion and Analysis dated October 31, 2012, which is available under the Company's profile on SEDAR at www.SEDAR.com.

Significant Events

Impairment of North East U.S. assets

As noted in the Company's MD&A for the year ended December 31, 2011, impairment charges or reversals of impairment charges are expected to occur more frequently than reported in the past due to changes in Canadian GAAP. Assets that are acquired or developed are initially recorded at their fair value which is subject to change as company, industry and general economic conditions fluctuate. The Company performs goodwill impairment testing on an annual basis and current assessments of fair value of its assets on a regular basis which may result in the recognition of impairment losses or reversals of losses.

During the second quarter of 2012, Capital Power recognized a pre-tax impairment charge of $74 million with respect to its North East U.S. plants which reduced the carrying amount of the related property, plant and equipment and goodwill. This impairment was based on reduced expected operating margins for the Bridgeport, Rumford and Tiverton plants largely as a result of weaker spark spreads in the North East U.S. power market. The reduction in spark spreads is attributable to market and other changes since the April 2011 acquisition of the North East U.S. assets; the fair value paid was consistent with other transactional values in the market at the time of acquisition. If expected operating margins strengthen, a portion of the impairment loss could be reversed. The impairment charge, after income taxes and non-controlling interests, has been excluded from net income attributable to shareholders in determining normalized earnings per share. The impairment charge has no cash flow impact.

Sale of hydro facilities

In June 2012, the Company announced that it had entered into an agreement to sell the limited partnership that owns the two British Columbia hydro facilities, Brown Lake and Miller Creek. The related net assets, at their carrying amount of $53 million, were classified as held for sale in the Company's September 30, 2012 statement of financial position. This transaction closed October 12, 2012. See Subsequent Event.

Debt and equity base shelf prospectuses

On June 12, 2012, CPLP filed a Canadian base shelf prospectus, which expires in July 2014, under which it may offer and issue medium term notes, due not less than one year from the date of issue, to the public in an aggregate principal amount not to exceed $1 billion.

On February 16, 2012, Capital Power filed a Canadian base shelf prospectus, which expires in March 2014, under which it may raise up to $2 billion collectively in common shares of the Company, preferred shares of the Company and subscription receipts exchangeable for common shares and/or other securities of the Company.

Secondary offering of Capital Power common shares by EPCOR

Effective April 5, 2012, EPCOR exchanged 9,775,000 of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9,775,000 common shares of Capital Power to the public pursuant to a secondary offering at $23.55 per common share. Capital Power did not receive any of the approximate $230 million of proceeds from EPCOR's sale of common shares. This transaction reduced EPCOR's ownership interest in CPLP to approximately 29% from its interest of approximately 39% at December 31, 2011 and reduced EPCOR's ownership of the common shares of Capital Power on a diluted basis to 29% from 39%. EPCOR has advised that it intends to sell all or a portion of its remaining interest in CPLP as its demands for capital require and market conditions permit.

Sale of Atlantic Power shares

On February 10, 2012, the Company completed the sale of its shares in Atlantic Power, which were acquired in November 2011 as part of the Atlantic Power acquisition of CPILP, for proceeds of $52 million on a bought deal basis. These shares were initially recorded at $48 million and subsequently adjusted to their fair value of $53 million as of December 31, 2011 resulting in an unrealized gain of $5 million recognized in 2011. For the three months ended March 31, 2012, the Company recognized a realized pre-tax gain of $4 million with income taxes estimated to be $1 million offset by the reversal of the unrealized gain of $5 million recognized in the previous year.

Subsequent Event

Sale of hydro facilities

Effective October 12, 2012, the disposal of the Company's hydro facilities was finalized and a pre-tax gain of approximately $11 million will be recorded in the Company's fourth quarter results. The actual pre-tax gain to be recorded could differ from this estimate as a result of working capital and other post-close purchase price adjustments to be finalized in the fourth quarter of 2012.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on November 1, 2012 at 1:00 PM (ET) to discuss third quarter results. The conference call dial-in numbers are:

(403) 532-5601 (Calgary)
(604) 681-8564 (Vancouver)
(416) 623-0333 (Toronto)
(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 859006# followed by participant code 21543#. The replay will be available until midnight on February 1, 2013.

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) EBITDA, (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) cash flow per share, (v) dividend coverage ratio, (vi) normalized earnings attributable to common shareholders, and (vii) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to gross income, net income, net income attributable of Shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective. Reconciliations of EBITDA to net income, funds from operations and funds from operations excluding non-controlling interests in CPILP to net cash flows from operating activities, normalized earnings attributable to common shareholders to net income attributable to common shareholders, and normalized earnings per share to earnings per share are contained in the Company's Management's Discussion and Analysis dated October 31, 2012 for the three months ended September 30, 2012 which is available under the Company's profile on SEDAR at www.SEDAR.com.

Forward-looking Information

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

Material forward-looking information in this press release includes information with respect to expectations regarding impact of power prices and expectations regarding frequency of the recognition of impairment losses.

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) power plant availability and performance including maintenance expenditures, (ii) changes in electricity prices in markets in which the Company operates, (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) acquisitions and developments including timing and costs of regulatory approvals and construction; (v) ability to fund current and future capital and working capital needs, (vi) changes in energy commodity market prices and use of derivatives, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's Management's Discussion and Analysis dated March 13, 2012 for further discussion of these and other risks.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated October 31, 2012, 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, 2012, the audited consolidated financial statements and MD&A of Capital Power Corporation for the year ended December 31, 2011, the annual information form (AIF) of Capital Power Corporation dated March 13, 2012 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.

As of January 1, 2011, International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board, became Canadian generally accepted accounting principles (GAAP) for the basis of preparation of financial statements for publicly accountable enterprises. The information presented in this MD&A, including information relating to comparative periods in 2011 and 2010, is presented in accordance with IFRS unless otherwise noted.

In this MD&A, financial information for the nine months ended September 30, 2012 and the nine months ended September 30, 2011 is based on the unaudited condensed interim consolidated financial statements of the Company for such periods which were prepared in accordance with 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 31, 2012.

Contents

The Business and Corporate Structure

Capital Power is a growth-oriented North American power producer headquartered in Edmonton, Alberta. The Company develops, acquires, operates and optimizes power generation from a variety of energy sources. Capital Power owns more than 3,300 megawatts (MW) of power generation capacity at 14 facilities across North America and has rights to 371 MW through its interest in the acquired Sundance C power purchase arrangement (acquired Sundance PPA). An additional 487 MW of owned wind generation capacity is under construction or in advanced development in Alberta, British Columbia, 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, 2012, 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. 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 representing approximately 29% of CPLP. CPLP's exchangeable common limited partnership units are exchangeable for common shares of Capital Power 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

The Company's corporate strategy of rationalizing its fleet with a greater fuel and technology focus, larger facilities, fewer markets and reduced fleet age remains unchanged from that disclosed in its 2011 annual MD&A. In June 2012, the Company announced that it had entered into an agreement to sell its two British Columbia hydro facilities, Brown Lake and Miller Creek. This transaction closed October 12, 2012 and completes the Company's strategic plan to dispose of its hydro plant assets. See Significant Events and Subsequent Event.

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, and (ix) expectations regarding capital expenditures for plant maintenance and other.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments, and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements relate to: (i) electricity and other energy prices, (ii) performance, (iii) business prospects and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates, and (vi) other matters discussed under the Performance Overview and Outlook sections.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are: (i) power plant availability and performance including maintenance expenditures, (ii) changes in electricity prices in markets in which the Company operates, (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) acquisitions and developments including timing and costs of regulatory approvals and construction, (v) ability to fund current and future capital and working capital needs, (vi) changes in energy commodity market prices and use of derivatives, (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, 2011 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	2012 full year target	Actual results for the nine months ended September 30, 2012
Plant availability average	91% or greater	92%
Capital expenditures for plant maintenance and other (excludes capital expenditures for Genesee mine lands)	$108 million or lower	$65 million
Maintenance and operating expenses	$215 million to $235 million	$153 million

On a year-to-date basis, the Company's plant availability averaged 92% which reflected strong third quarter performance of the Alberta commercial plants offset by the impact of an unscheduled outage for Genesee 1 in the third quarter and in the second quarter, planned outages for Genesee 2, Bridgeport, Rumford, Tiverton and the North Carolina U.S. plants and an unscheduled outage for Bridgeport due to a condenser leak. In the first quarter, strong performances of Genesee Units 1 and 2, Keephills 3 and Joffre were partly offset by the Genesee 3 outage which continued from November 11, 2011 until January 15, 2012. The plant availability average is on track to meet the target for full year 2012.

Capital expenditures for maintenance of the plants and other for the nine months ended September 30, 2012 were behind the levels expected to be incurred but it is anticipated that spending will increase during the remainder of 2012 with the resulting full year amount being close to 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, 2012 were consistent with the target range for full year 2012.

Financial stability and strength

Performance measure	2012 full year target	Actual results for the nine months ended September 30, 2012
Normalized earnings per share (1)	$1.50 to $1.70	$1.06
Funds from operations (1)	$380 million to $420 million	$298 million
Cash flow per share (1)	$3.90 to $4.30	$3.05
Dividend coverage ratio (1)	2.2 to 2.6	2.3

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

Actual financial results achieved in the nine months ended September 30, 2012 compared with the 2012 financial targets were most significantly impacted by lower than expected EBITDA(2) for the North East U.S. plants due primarily to the second quarter unplanned outage at Bridgeport and lower than expected power pricing and spark spreads. The results for North Carolina U.S. plants were also under target primarily due to higher than expected maintenance costs incurred during planned outages and higher fuel costs.

(2) Earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses and gains on acquisitions and disposals (EBITDA) is a non-GAAP financial measure. See Non-GAAP Financial Measures.

Enhancing shareholders' value

Performance measure	2012 full year target	Status at September 30, 2012
Halkirk wind project	Continue on budget of $357 million and on time with commercial operation date in the fourth quarter of 2012	On track with targets; commercial operation date expected mid-December 2012 and project costs tracking slightly under budget.
Quality Wind project	Continue on budget of $455 million and on time with commercial operation date in the fourth quarter of 2012	On track to be under budget by approximately 10% with commercial operation date planned for early November 2012.
Port Dover & Nanticoke and K2 wind projects	Full notice to proceed in 2012	Limited notice to proceed received for Port Dover & Nanticoke Full notice to proceed for K2 revised to 2013

These growth projects are all on track with their targets except that the Company has revised its expectation for the timing of full notice to proceed on the K2 wind project from 2012 to 2013. The commercial operation date for Quality Wind is expected to be in early November 2012 while the forecast total project costs have decreased by approximately 10% from budget. This decrease is attributed primarily to strong project management including the impact of up-front planning and project execution steps such as value engineering, constructability improvements and supply chain optimization. The expected commissioning date for K2 (see Outlook) and its total project costs remain unchanged. The Port Dover & Nanticoke wind project received its Renewable Energy Approval (REA) from the Government of Ontario on July 17, 2012 and construction has commenced. Appeals to the REA have been filed by two groups and decisions are expected in the first quarter of 2013. To date, recent similar appeals filed against other Ontario wind projects with REA have been unsuccessful.

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.

Normalized earnings per share, as reflected in the 2012 targets and based on forecast power prices and spark spreads, was expected to be in the range of $1.50 to $1.70 for the full year. Normalized earnings per share for 2012 is now expected to be slightly under the low end of the target range based upon revised full year Alberta spot and forward power prices which have decreased by approximately $12 per megawatt hour (MWh) and the impact of unplanned and extended planned outages at the North East U.S. plants. Funds from operations, cash flow per share and dividend coverage ratio are expected to be near the low end of their target ranges. See Performance Overview for these targets.

As of September 30, 2012, 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 2012	Full year 2013	Full year 2014
Percentage sold forward	69%	32%	14%
Contracted price ($/MWh)	Mid-60	Mid-60	Mid-60

The 2012 results will include a full year of operations from the New England facilities acquired in April 2011 and from Keephills 3 which began commercial operation in September 2011. The New England facilities are expected to contribute EBITDA of approximately $33 million in 2012 consistent with the expectations disclosed in the second quarter MD&A. The expected full year EBITDA of $41 million as disclosed in the first quarter decreased primarily due to the impact of the second quarter unplanned outage at the Bridgeport plant. Expectations for EBITDA contributions of $6 million from the North Carolina U.S. plants in the last six months of the year have decreased to $2 million due primarily to the third quarter impact of unanticipated adjustments to physical coal inventory at the Southport plant resulting in higher than expected fuel costs. The full year EBITDA contribution from the North Carolina U.S. plants is now expected to be $4 million.

Results from the Quality Wind and Halkirk wind projects will be included in Capital Power's results from their commercial operation dates which are expected in the fourth quarter of 2012.

The plant availability target for 2012 of 91% reflects two significant scheduled maintenance outages, one at Genesee 2 and one at Genesee 3, and lesser impact planned outages at the U.S. plants. The second quarter outage at Genesee 2 lasted 24 days with capitalized maintenance costs of approximately $16 million and availability penalties of $6 million. The Genesee 2 outage costs were lower than expected because availability penalties were based on lower power prices than expected. The planned third quarter outage at Genesee 3 was delayed until the fourth quarter. It is expected to last 36 days and Capital Power's portion of the maintenance cost is expected to be $10 million. The length of the Genesee 3 outage and Capital Power's costs have increased from the second quarter estimate because of greater than expected work required to inspect and repair certain piping. In the third quarter of 2012, a trial project at Genesee 1 resulted in an unplanned outage of 8 days which reduced revenues by approximately $7 million. The scheduled outages for the North East U.S. plants of Bridgeport, Rumford and Tiverton were expected to cost approximately $9 million for full year 2012. Those expected costs increased by $2 million primarily due to the unplanned Bridgeport plant outage in the second quarter of 2012.

The 2012 results will not include results from CPILP which was sold effective November 2011.

The 2012 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. However, they do not include the effects of potential future acquisitions or development activities, or potential impacts from unplanned plant outages including outages at facilities of other market participants, and the related impacts on market power prices.

The Company's estimated 2012 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, 2012 estimated**
Quality Wind	4th quarter 2012	245 to 260
Halkirk	4th quarter 2012	174
Port Dover & Nanticoke	4th quarter 2013	40
K2 (1)	2014	2
		461 to 476

(1) Capital Power entered into a partnership agreement to develop K2 which is expected to be in operation by 2014. The 2012 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 2012 capital expenditures for growth projects has decreased from $572 million as was disclosed in the Company's December 31, 2011 MD&A. The decrease is due to the delay in timing of certain project payments from 2012 to 2013 and a decrease in the expected total capital expenditures for the Quality Wind project as it nears its commercial operation date. The total project estimated costs for the other growth projects remain unchanged. See Performance Overview.

(unaudited, $ millions) **Capital expenditures – sustaining**	**Year ended December 31, 2012 estimated**
Plant maintenance	80
Genesee mine maintenance (1) (2)	24
Information technology (3)	21
Other	1
	126

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

(2) Included in the estimated capital expenditures for Genesee mine maintenance is approximately $18 million relating to purchase of lands for ongoing expansion of the mine.

(3) The 2012 estimated capital expenditures for information technology are primarily for a new energy trading and risk management system and a new enterprise resource planning system.

Based on the actual expenditures for the nine months ended September 30, 2012 and the current forecast for the last quarter, estimated 2012 sustaining capital expenditures are $126 million which is close to the estimate included in the Company's December 31, 2011 MD&A.

As noted in the Company's MD&A for the year ended December 31, 2011, impairment charges or reversals of impairment charges are expected to occur more frequently than reported in the past due to changes in Canadian GAAP. Assets that are acquired or developed are initially recorded at their fair value which is subject to change as company, industry and general economic conditions fluctuate. The Company performs goodwill impairment testing on an annual basis and current assessments of fair value of its assets on a regular basis which may result in the recognition of impairment losses or reversals of losses such as the second quarter's impairment loss with respect to its North East U.S. plants. See Significant Events.

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, after the completion of the first phase of the proceeding, the AUC issued its decision that the factors utilized from 2006 to the present time were non-compliant with the applicable legislation and regulations. The future second phase of the proceeding will consider what alternative factors should be implemented and whether they will be retroactively applied. However, the AUC has advised that the second phase will not proceed until the process to consider the appeals of the first phase decision has been concluded. Capital Power may incur additional payments for transmission charges on a retroactive and go-forward basis but a provision has not been recorded in the Company's financial statements since the timing of completion and outcome of the first phase appeals and the second phase of the proceeding are not known.

The Company has been in negotiations with Communications, Energy and Paperworkers Union of Canada Local 1123 at the Island Generation facility to renew its labour contract which expired in April 2012. To date, these negotiations have not been successful and the Company locked out the union employees on October 30, 2012. The Company has adequate management staffing and contingency plans to continue to operate the plant during this labour disruption.

The recent storm, Sandy, had no impact on Capital Power's North East U.S. and North Carolina U.S. plants except that the Bridgeport plant was pre-emptively taken offline, as a safety precaution, from October 29 to 30, 2012.

In August 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 total amount receivable of $17 million recorded on Capital Power's September 30, 2012 statement of financial position was reduced by related insurance recoveries.

On July 23, 2012, TransAlta Corporation (TransAlta) and TransCanada Corporation reported the independent arbitration panel's decision regarding TransAlta's claims of force majeure and destruction for its Sundance Units 1 and 2 which are now expected to return to service in the fall of 2013. The return to service will add 560 MWs of power to the Alberta market which is expected to decrease Alberta power prices. Capital Power's earnings and cash flow will be negatively affected until such time as equivalent demand increases or existing supply is retired from the market.

Non-GAAP Financial Measures

The Company uses (i) earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses, and gains on acquisitions and disposals (EBITDA), (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) cash flow per share, (v) dividend coverage ratio, (vi) normalized earnings attributable to common shareholders, and (vii) normalized earnings per share as financial performance measures.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and are therefore unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to gross income, net income, net income attributable 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.

EBITDA

Capital Power uses 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 defined EBITDA as earnings before finance expense, income tax expense and depreciation and amortization. Commencing with the Company's December 31, 2011 year-end, EBITDA was redefined to also exclude impairments, foreign exchange losses and gains on acquisitions and disposals. Management believes that EBITDA, as a measure of plant operating performance, is more meaningful if results not related to plant operations such as impairments, foreign exchange losses and gains on acquisitions and disposals are excluded from the EBITDA measure. All comparative EBITDA amounts for quarters prior to those ended on December 31, 2011 were revised to reflect this change. A reconciliation of EBITDA to net income is as follows:

(unaudited, $ millions)	Three months ended							
	Sep 30 2012	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**
Revenues	392	249	368	382	414	455	440	430
Other income	2	12	12	25	19	17	18	5
Energy purchases and fuel	(162)	(110)	(147)	(169)	(189)	(255)	(291)	(233)
Gross income	232	151	233	238	244	217	167	202
Other raw materials and operating charges	(29)	(36)	(30)	(40)	(43)	(37)	(29)	(43)
Staff costs and employee benefits expense	(39)	(34)	(36)	(34)	(40)	(42)	(39)	(44)
Other administrative expenses	(12)	(17)	(15)	(14)	(22)	(26)	(15)	(24)
EBITDA	**152**	**64**	**152**	**150**	**139**	**112**	**84**	**91**
Depreciation and amortization	(52)	(53)	(54)	(62)	(45)	(64)	(58)	(63)
Impairments	-	(74)	-	-	-	(43)	-	1
Foreign exchange losses	-	-	-	-	(7)	(4)	(2)	(1)
Gains on acquisitions and disposals	-	-	-	93	-	-	-	2
Finance expense	(19)	(17)	(18)	(29)	(32)	(35)	(9)	(13)
Income tax recovery (expense)	(18)	22	(14)	-	(11)	12	(1)	5
Net income (loss)	**63**	**(58)**	**66**	**152**	**44**	**(22)**	**14**	**22**
Net income (loss) attributable to:								
Non-controlling interests	24	(26)	26	68	29	3	11	25
Shareholders of the Company	39	(32)	40	84	15	(25)	3	(3)
Net income (loss)	**63**	**(58)**	**66**	**152**	**44**	**(22)**	**14**	**22**

Funds from operations and funds from operations excluding non-controlling interests in CPILP

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 and distributions to the Company's shareholders. Funds from operations are net cash flows from operating activities, including finance and current income tax expenses, and excluding 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.

The Company divested its 29% indirect ownership of CPILP as of November 5, 2011. Prior to the sale, the Company used funds from operations excluding non-controlling interests in CPILP to provide a more meaningful measure of the Company's operating cash flows since the non-controlling interests in CPILP's funds from operations were approximately 71%.

A reconciliation of net cash flows from operating activities to (i) funds from operations and (ii) funds from operations excluding non-controlling interests in CPILP is as follows:

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
Net cash flows from operating activities per Consolidated Statements of Cash Flows	**75**	**142**	**213**	**310**
Reversal of previously recognized unrealized losses representing changes in the fair value of forward bond contracts	-	4	(8)	(2)
Loss on the settlement of forward bond contracts	-	-	7	12
Miscellaneous financing charges	4	2	7	6
Finance expense	(19)	(32)	(54)	(76)
Interest paid	14	13	37	44
Current income tax (expense) recovery	(1)	1	(4)	-
Income taxes paid	1	1	6	13
Change in non-cash operating working capital	54	13	94	27
Funds from operations	**128**	**144**	**298**	**334**
Less funds from operations due to non-controlling interests in CPILP	-	28	-	70
Funds from operations excluding non-controlling interests in CPILP	**128**	**116**	**298**	**264**

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	
	2012	**2011**	**2012**	**2011**
Funds from operations excluding non-controlling interest in CPILP ($ millions)	**128**	**116**	**298**	**264**
Weighted average common shares outstanding (millions)	69.52	48.33	65.8	40.42
Weighted average exchangeable common limited partnership units of CPLP outstanding (millions)	28.44	47.42	31.87	47.42
Weighted average shares and partnership units outstanding (millions)	97.96	95.75	97.67	87.84
Cash flow per share ($)	**1.31**	**1.21**	**3.05**	**3.01**

Dividend coverage ratio

Capital Power uses the dividend coverage ratio as a measure of the Company's ability to pay dividends and distributions to its shareholders and CPLP's exchangeable common limited partnership unitholders from funds it generates from operations. The measure is calculated as funds from operations excluding non-controlling interests in CPILP less sustaining capital expenditures divided by dividends and distributions.

(unaudited, $ millions except dividend coverage ratio)	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
Funds from operations excluding non-controlling interests in CPILP	**128**	**116**	**298**	**264**
Less CPLP sustaining capital expenditures	17	11	82	45
Less CPLP's share of CPILP sustaining capital expenditures	-	1	-	4
Funds available for distribution	111	104	216	215
Common share dividends declared	22	16	62	41
Distributions to exchangeable common limited partnership unitholders of CPLP declared	9	15	30	45
Preferred share dividends declared	1	1	4	4
Total dividends and distributions declared	32	32	96	90
Dividend coverage ratio	**3.5**	**3.3**	**2.3**	**2.4**

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 earnings (loss) per share to normalized earnings per share is as follows:

(unaudited, $ millions except per share amounts)	Three months ended							
	Sep 30 2012	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**
Earnings (loss) per share ($)	**0.55**	**(0.50)**	**0.66**	**1.47**	**0.29**	**(0.67)**	**0.06**	**(0.13)**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income	**39**	**(32)**	**40**	**84**	**15**	**(25)**	**3**	**(3)**
Preferred share dividends	(1)	(2)	(1)	(2)	(1)	(2)	(1)	-
Earnings (loss) attributable to common shareholders	38	(34)	39	82	14	(27)	2	(3)
Impairment loss on North East U.S. assets	-	37	-	-	-	-	-	-
Unrealized changes in fair value of CPLP's derivative instruments	(4)	4	(12)	2	2	2	9	3
Genesee 1 unplanned outage costs due to plant research and development project	4	-	-	-	-	-	-	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	-	(2)	-	1	1	-	-	1
Gain on sale of CPILP	-	-	-	(60)	-	-	-	-
Gain on settlement of pension expense from sale of CPILP	-	-	-	(3)	-	-	-	-
Unrealized changes in fair value of CPILP's derivative instruments	-	-	-	(1)	2	-	-	(1)
Gain on sale of Taylor Coulee Chute	-	-	-	(1)	-	-	-	-
Foreign exchange losses on translation of U.S. dollar debt	-	-	-	-	2	-	-	-
Impairment loss on manager and operating contracts	-	-	-	-	-	30	-	-
Acquisition loss for Island Generation acquisition	-	-	-	-	-	-	-	6
Income tax adjustments	-	-	-	-	-	(2)	-	(1)
Normalized earnings attributable to common shareholders	**38**	**5**	**27**	**20**	**21**	**3**	**11**	**5**
Weighted average number of common shares outstanding (millions)	69.52	68.51	59.18	55.64	48.33	40.42	32.32	23.47
Normalized earnings per share ($)	**0.55**	**0.07**	**0.46**	**0.36**	**0.43**	**0.07**	**0.34**	**0.21**

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 and dividend coverage ratio)	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
Revenues and other income	394	433	1,035	1,363
EBITDA [1]	152	139	368	335
Net income	63	44	71	36
Net income (loss) attributable to shareholders of the Company	39	15	47	(7)
Normalized earnings attributable to common shareholders [1]	38	21	70	35
Earnings (loss) per share ($)	0.55	0.29	0.65	(0.27)
Diluted earnings (loss) per share ($) [2]	0.55	0.29	0.63	(0.27)
Normalized earnings per share ($) [1]	0.55	0.43	1.06	0.87
Funds from operations [1]	128	144	298	334
Funds from operations excluding non-controlling interests in CPILP [1]	128	116	298	264
Cash flow per share ($) [1]	1.31	1.21	3.05	3.01
Capital expenditures	150	107	433	316
Dividend coverage ratio [1]	3.5	3.3	2.3	2.4
Dividends per common share, declared ($)	0.3150	0.3150	0.9450	0.9450
Dividends per preferred share, declared ($)	0.2875	0.2875	0.8625	0.9058

	As at	
	September 30, 2012	**December 31, 2011**
Loans and borrowings including current portion	1,665	1,480
Total assets	5,033	4,743

(1) The consolidated financial highlights, except for EBITDA, normalized earnings attributable to common shareholders, normalized earnings per share, funds from operations, funds from operations excluding non-controlling interests in CPILP, cash flow per share, and dividend coverage ratio, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

(2) Diluted earnings per share was calculated after giving effect to share purchase options and the 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 and normalized earnings per share were determined by excluding the total of net unrealized changes in the fair value of derivative instruments and the reversal of unrealized losses on forward bond contracts recognized in prior periods. Accordingly, the impact of the reversal of the unrealized changes reduced normalized earnings by $26 million for the nine months ended September 30, 2012 and increased normalized earnings by $37 million for the nine months ended September 30, 2011 before consideration of taxes and non-controlling interests.

Finance expense included the reversal of previously recognized unrealized decreases in the fair value of forward bond contracts of $8 million for the nine months ended September 30, 2012 and $2 million in the same period of the prior year. These reversals decreased finance expense and increased net income but were offset by the realized losses of $7 million and $12 million (for the nine months ended September 30, 2012 and 2011, respectively) recognized on the settlement of these contracts which were also included in finance expense. These contracts economically hedged the Company’s exposure to interest rate risk on anticipated debt issues. While these contracts settled at a loss, future interest payments on the debt were and will be incurred at a rate lower than the rate that was locked in by the hedge.

An additional significant adjustment to determine normalized earnings and normalized earnings per share was the exclusion of the second quarter pre-tax impairment of $74 million related to the North East U.S. plants. See Significant Events.

Funds from operations

Changes in funds from operations for the three and nine months ended September 30, 2012 compared to the same periods in the prior year are consistent with the changes in net income attributable to shareholders of the Company.

Significant Events

Impairment of North East U.S. assets

During the second quarter of 2012, Capital Power recognized a pre-tax impairment charge of $74 million with respect to its North East U.S. plants which reduced the carrying amount of the related property, plant and equipment and goodwill. This impairment was based on reduced expected operating margins for the Bridgeport, Rumford and Tiverton plants largely as a result of weaker spark spreads in the North East U.S power markets. The reduction in spark spreads is attributable to market and other changes since the April 2011 acquisition of the North East U.S. assets; the fair value paid was consistent with other transactional values in the market at the time of acquisition. If expected operating margins strengthen, a portion of the impairment loss could be reversed. The impairment charge, after income taxes and non-controlling interests, was excluded from net income attributable to shareholders in determining normalized earnings per share. The impairment charge had no cash flow impact.

Sale of hydro facilities

In June 2012, the Company announced that it had entered into an agreement to sell the limited partnership that owns the two British Columbia hydro facilities, Brown Lake and Miller Creek. The related net assets, at their carrying amount of $53 million, were classified as held for sale in the Company's September 30, 2012 statement of financial position. This transaction closed October 12, 2012. See Subsequent Event.

Debt and equity base shelf prospectuses

On June 12, 2012, CPLP filed a Canadian base shelf prospectus, which expires in July 2014, under which it may offer and issue medium-term notes, due not less than one year from the date of issue, to the public in an aggregate principal amount not to exceed $1 billion.

On February 16, 2012, Capital Power filed a Canadian base shelf prospectus, which expires in March 2014, under which it may raise up to $2 billion collectively in common shares of the Company, preferred shares of the Company and subscription receipts exchangeable for common shares and/or other securities of the Company.

Secondary offering of Capital Power common shares by EPCOR

Effective April 5, 2012, EPCOR exchanged 9,775,000 of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9,775,000 common shares of Capital Power to the public pursuant to a secondary offering at $23.55 per common share. Capital Power did not receive any of the approximate $230 million of proceeds from EPCOR's sale of common shares. This transaction reduced EPCOR's ownership interest in CPLP to approximately 29% from its interest of approximately 39% at December 31, 2011. EPCOR has advised that it intends to sell all or a portion of its remaining interest in CPLP as its demands for capital require and market conditions permit.

$250 million debt issue

On February 21, 2012, CPLP completed a public offering of $250 million unsecured medium-term notes. The notes have a coupon rate of 4.85%, are payable semi-annually commencing on August 21, 2012 and mature on February 21, 2019. The net proceeds of the offering were used for repayment of amounts owing under credit facilities, financing on ongoing capital projects, working capital requirements, and general corporate purposes.

Sale of Atlantic Power shares

On February 10, 2012, the Company completed the sale of its shares in Atlantic Power, which were acquired in November 2011 as part of the Atlantic Power acquisition of CPILP, for proceeds of $52 million on a bought deal basis. These shares were initially recorded at $48 million and subsequently adjusted to their fair value of $53 million as of December 31, 2011 resulting in an unrealized gain of $5 million recognized in 2011. In the first quarter of 2012, the Company recognized a realized pre-tax gain of $4 million with income taxes estimated to be $1 million offset by the reversal of the unrealized gain of $5 million recognized in the previous year.

Subsequent Event

Sale of hydro facilities

Effective October 12, 2012, the disposal of the Company's hydro facilities was finalized and a pre-tax gain of approximately $11 million will be recorded in the Company's fourth quarter results. The actual pre-tax gain to be recorded could differ from this estimate as a result of working capital and other post-close purchase price adjustments to be finalized in the fourth quarter of 2012.

Plant Summary

		Three months ended September 30					
		2012	2011	2012	2011	2012	2011
	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 and CPILP plants		4,575	4,221	97%	97%	283	274
Alberta commercial plants and acquired Sundance PPA							
Genesee 3 [4]	Coal	507	496	100%	100%	38	47
Keephills 3 [5]	Coal	489	336	100%	100%	38	15
Joffre	Natural gas	87	90	98%	99%	17	19
Clover Bar Energy Centre 1, 2 and 3	Natural gas	130	57	97%	91%	25	21
Taylor Coulee Chute [6]	Water flows	n/a	12	n/a	100%	n/a	1
Clover Bar Landfill Gas	Landfill gas	8	9	92%	86%	1	1
Alberta commercial plants – owned		1,221	1,000	99%	97%	119	104
Acquired Sundance PPA	Coal	738	545	97%	72%	59	47
		1,959	1,545	98%	89%	178	151
Alberta contracted plants							
Genesee 1	Coal	755	843	93%	100%		
Genesee 2	Coal	815	845	99%	100%		
		1,570	1,688	96%	100%	69	87
Ontario and British Columbia contracted plants							
Kingsbridge 1	Wind	15	12	99%	99%	1	-
Miller Creek	Water flows	22	49	71%	92%	-	2
Brown Lake	Water flows	14	8	99%	53%	1	1
Island Generation	Natural gas	8	-	100%	100%	10	9
		59	69	97%	98%	12	12
North East U.S. commercial plants [7]							
Bridgeport	Natural gas	905	872	95%	96%	33	39
Rumford	Natural gas	229	170	97%	95%	13	11
Tiverton	Natural gas	416	422	99%	97%	18	21
		1,550	1,464	97%	96%	64	71
North Carolina U.S. contracted plants [8]							
Roxboro	Mixed [9]	64	n/a	97%	n/a	5	n/a
Southport	Mixed [9]	111	n/a	100%	n/a	14	n/a
		175	n/a	99%	n/a	19	n/a
CPILP plants [10]	Various	n/a	1,294	n/a	96%	n/a	139

		Nine months ended September 30					
		2012	2011	2012	2011	2012	2011
	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 and CPILP plants		12,296	9,879	92%	94%	703	611
Alberta commercial plants and acquired Sundance PPA							
Genesee 3 [4]	Coal	1,359	1,455	93%	100%	82	109
Keephills 3 [5]	Coal	1,392	386	98%	100%	80	15
Joffre	Natural gas	276	245	97%	92%	41	44
Clover Bar Energy Centre 1, 2 and 3	Natural gas	297	259	97%	74%	43	52
Taylor Coulee Chute [6]	Water flows	n/a	14	n/a	98%	n/a	1
Clover Bar Landfill Gas	Landfill gas	25	26	91%	89%	2	2
Alberta commercial plants – owned		3,349	2,385	96%	88%	248	223
Acquired Sundance PPA	Coal	2,093	2,004	94%	87%	127	145
		5,442	4,389	96%	88%	375	368
Alberta contracted plants							
Genesee 1	Coal	2,336	2,272	95%	91%		
Genesee 2	Coal	2,247	2,465	91%	100%		
		4,583	4,737	93%	95%	207	228
Ontario and British Columbia contracted plants							
Kingsbridge 1	Wind	74	67	99%	99%	5	4
Miller Creek	Water flows	42	80	65%	90%	-	2
Brown Lake	Water flows	45	37	99%	84%	3	3
Island Generation	Natural gas	74	107	100%	100%	30	29
		235	291	97%	98%	38	38
North East U.S. commercial plants [7]							
Bridgeport	Natural gas	2,049	1,517	76%	97%	84	71
Rumford	Natural gas	349	238	93%	96%	23	16
Tiverton	Natural gas	1,222	711	92%	97%	48	35
		3,620	2,466	84%	97%	155	122
North Carolina U.S. contracted plants [8]							
Roxboro	Mixed [9]	180	n/a	92%	n/a	16	n/a
Southport	Mixed [9]	329	n/a	94%	n/a	39	n/a
		509	n/a	94%	n/a	55	n/a
CPILP plants [10]	Various	n/a	3,588	n/a	92%	n/a	396

(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) Keephills 3 includes pre-commissioning output until commissioning date of September 1, 2011. Revenues and expenses related to commissioning activities were capitalized as part of the cost of the facility in property, plant and equipment.

(6) Taylor Coulee Chute was disposed of on November 1, 2011.

(7) North East U.S. commercial plants comprises the Bridgeport and the Rumford and Tiverton facilities as of their dates of acquisition of April 28, 2011 and April 29, 2011, respectively.

(8) North Carolina U.S. contracted plants comprises the Roxboro and Southport plants acquired from CPILP as of their date of acquisition of November 5, 2011. Prior to that date, these plants are included in the CPILP plants category.

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

(10) In November 2011, the CPILP plants, excluding Roxboro and Southport, were disposed of as part of the Atlantic Power acquisition of CPILP partnership units.

Portfolio Optimization

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

		Three months ended September 30		Nine months ended September 30		Year ended December
	Unit	**2012**	**2011**	**2012**	**2011**	**31, 2011**
Alberta portfolio						
Hedged position [1]	Percentage sold forward at beginning of period (%)	91	80	48	73	73
Realized power price [2]	$/MWh	81	74	74	65	68
Spot power price averages	$/MWh	78	95	59	76	76
North East U.S portfolio [3]						
Hedged position	Approximate average percentage hedged at the beginning of the period (%)	46	55	46	55	55

(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.

(3) The North East U.S. portfolio activities commenced upon the acquisition of the Bridgeport and the Rumford and Tiverton facilities on April 28 and April 29, 2011.

Consolidated Net Income

The primary factors contributing to the change in net income for the three and nine months ended September 30, 2012 compared with the three and nine months ended September 30, 2011 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, 2011	**44**	**36**
Decrease in EBITDA for CPILP plants	(48)	(129)
Increase in EBITDA for Alberta plants and portfolio primarily due to higher generation and portfolio performance	41	101
Increase in net unrealized gains on fair value adjustments of derivative instruments including forward bond sale contracts and Atlantic Power shares	36	74
Decrease in EBITDA of Alberta contracted plants	(19)	(21)
Decrease in realized foreign exchange loss	10	15
Decrease in interest expense	9	11
(Increase) decrease in depreciation and amortization expense	(7)	8
Increase in EBITDA of Other portfolio activities	4	9
Decrease in Corporate EBITDA	(2)	(4)
Increase in EBITDA of North East U.S. plants	2	6
Increase in impairments due to loss on North East U.S plants recorded in 2012 compared to the loss on CPILP operation and management contracts recorded in 2011	-	(31)
Decrease in realized losses on settled forward bond contracts	-	5
Increase in EBITDA of North Carolina U.S. contracted plants	-	2
Other	-	(1)
Increase in income before tax	26	45
Increase in income tax	(7)	(10)
Increase in net income	**19**	**35**
Consolidated net income for the periods ended September 30, 2012	**63**	**71**

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) CPILP plants, (vii) Other portfolio activities, and (viii) Corporate.

Financial results

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
Revenues and other income				
Alberta commercial plants, acquired Sundance PPA and portfolio optimization [1]	207	144	528	625
Alberta contracted plants	69	87	207	228
Ontario and British Columbia contracted plants	12	12	38	38
North East U.S. commercial plants and portfolio optimization [2]	62	71	155	122
North Carolina U.S. contracted plants [3]	19	-	55	-
CPILP plants	-	139	-	396
Other portfolio activities	10	19	43	71
Corporate	5	5	21	17
Interplant category transaction eliminations	(8)	(16)	(33)	(53)
	376	461	1,014	1,444
Unrealized changes in fair value of CPLP's energy derivative instruments, and Atlantic Power shares	18	(5)	21	(62)
Unrealized changes in fair value of CPILP's foreign exchange contracts	-	(23)	-	(19)
	18	(28)	21	(81)
	394	**433**	**1,035**	**1,363**
EBITDA [4]				
Alberta commercial plants, acquired Sundance PPA and portfolio optimization [1]	113	72	255	154
Alberta contracted plants	38	57	118	139
Ontario and British Columbia contracted plants	8	8	27	28
North East U.S. commercial plants and portfolio optimization [2]	12	10	26	20
North Carolina U.S. contracted plants [3]	-	-	2	-
CPILP plants	-	48	-	129
Other portfolio activities	4	-	11	2
Corporate	(30)	(28)	(83)	(79)
	145	167	356	393
Unrealized changes in fair value of CPLP's energy derivative instruments, and Atlantic Power shares	7	(5)	12	(39)
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	-	(23)	-	(19)
	7	(28)	12	(58)
	152	**139**	**368**	**335**

(1) Alberta commercial plants, acquired Sundance PPA and portfolio optimization include Keephills Unit 3 as of its date of commissioning of September 1, 2011. Revenues and expenses related to commissioning activities, prior to September 1, 2011 were capitalized as part of the cost of the facility in property, plant and equipment.

(2) North East U.S. commercial plants and portfolio optimization include Bridgeport and the Rumford and Tiverton facilities as of their dates of acquisition of April 28, 2011 and April 29, 2011, respectively.

(3) North Carolina U.S. contracted plants comprises the Roxboro and Southport plants acquired from CPILP as of their date of acquisition of November 5, 2011.

(4) The results by plant category and other, except for EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

Spot price averages	Three months ended September 30		Nine months ended September 30	
	2012	2011	2012	2011
Alberta power ($/MWh)	78	95	59	76
New England mass hub (US$/MWh)(1)	37	47	33	49
Alberta natural gas (AECO) ($/Gj)(2)	2.16	3.47	2.01	3.57

(1) The New England plants were acquired in April 2011.

(2) Gigajoule (Gj) 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	
	2012	2011	2012	2011
Electricity generation (GWh)	1,959	1,545	5,442	4,389
Availability (%)	98	89	96	88
Revenues (unaudited, $ millions)	207	144	528	625
EBITDA (unaudited, $ millions) (2)	113	72	255	154

(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 EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

Production increased 414 GWh for the third quarter of 2012 compared with the same quarter of 2011 primarily due to the addition of Keephills 3 which commenced commercial operations in September 2011, higher generation from the Company's CBEC units and higher generation from the acquired Sundance PPA units which experienced an outage in the third quarter of 2011. The addition of Keephills 3 contributed most of the increase in production of 1,053 GWh for the nine months ended September 30, 2012 compared with the corresponding period in 2011. Overall availability for the three and nine months ended September 30, 2012 was higher compared with the corresponding period in 2011 reflecting the impact of the 2011 outages of the units associated with the acquired Sundance PPA. Higher overall availability for the nine months ended September 30, 2012 compared to the same period in 2011 was also due to the increased availability from the Joffre and CBEC plants. Joffre experienced scheduled and unscheduled outages for two of the three turbines in the second quarter of 2011 with no outages in 2012. CBEC Unit 3 was offline from January 15, 2011 to June 17, 2011 due to blade damage in its high pressure compressor with no comparable outages in the first three quarters of 2012. The year-to-date overall availability on a comparative basis was reduced by availability at Genesee 3 which incurred an unplanned outage in the first quarter of 2012. Genesee 3 went offline on November 11, 2011 and returned to service on January 15, 2012. The unit went offline due to an electrical issue that resulted in damage to the turbine/generator bearings and rotor.

Average Alberta spot power prices of $78/MWh and $59/MWh for the three and nine months ended September 30, 2012 were significantly lower than the corresponding periods of 2011 which had average spot prices of $95/MWh and $76/MWh, respectively. In the three and nine months ended September 30, 2011, higher Alberta spot prices reflected higher price volatility compared with the current year periods due to a tighter supply demand balance primarily related to the unexpected shutdown of two large coal plants, other generation outages, and cooler than normal weather.

Higher revenues for the three months ended September 30, 2012 compared with the same period in 2011 were driven by portfolio optimization strategies employed by the Company whereby the lower 2012 average pool prices created more significant gains due to the Company's shorter position in 2012 compared to 2011 and incremental revenues from Keephills 3 which commenced commercial operations in September 2011. Lower revenues for the nine months ended September 30, 2012 compared with the same periods in 2011 reflected lower rate regulated tariff sales to Alberta local distribution companies, the impact of lower Alberta power prices on portfolio generation, and the Genesee 3 outage in late 2011 and early 2012. Lower revenues in 2012 were partly offset by incremental revenues from Keephills 3.

The increase in EBITDA for the three and nine months ended September 30, 2012 compared with the corresponding periods in 2011 was primarily driven by the impact of lower average pool prices on the Company's position which influenced the portfolio optimization strategies employed by the Company. The lower EBITDA for the nine months ended September 30, 2011 also reflected the unfavourable impact of a sudden increase in Alberta power prices on the commodity optimization portfolio in the first quarter of 2011.

Alberta contracted plants

	Three months ended September 30		Nine months ended September 30	
Alberta contracted plants	**2012**	**2011**	**2012**	**2011**
Electricity generation (GWh)	1,570	1,688	4,583	4,737
Availability (%)	96	100	93	95
Revenues (unaudited, $ millions)	69	87	207	228
EBITDA (unaudited, $ millions) (1)	38	57	118	139

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

Revenues and EBITDA for the three and nine months ended September 30, 2012 compared with the corresponding periods in 2011 reflected lower capacity payments revenues, availability incentive revenues, and fly ash sales partly offset by higher energy payment revenues. The decrease in capacity payment revenues was due to the decrease in the asset base of the plants and lower rates on government bonds which are both inputs to the capacity payment calculation. For the third quarter of 2012, lower availability incentive revenues were the result of lower availability due to a forced outage at Genesee Unit 1 from September 20, 2012 to September 27, 2012 resulting from a trial project intended to increase the marketability of the fly ash by-product and lower rolling average power prices driven by lower Alberta spot power prices. The Genesee 1 outage reduced revenues and EBITDA by approximately $7 million. Higher energy payment revenues reflected an increase in the Statistics Canada indices which are an input to the energy payment calculation. EBITDA for the nine months ended September 30, 2012 reflected lower maintenance costs compared to the same period in 2011 primarily due to lower costs incurred for the Genesee Unit 2 turnaround completed in 2012 compared with the Genesee Unit 1 turnaround completed in 2011.

Ontario and British Columbia contracted plants

	Three months ended September 30		Nine months ended September 30	
Ontario and British Columbia contracted plants	**2012**	**2011**	**2012**	**2011**
Electricity generation (GWh)	59	69	235	291
Availability (%)	97	98	97	98
Revenues (unaudited, $ millions)	12	12	38	38
EBITDA (unaudited, $ millions) (1)	8	8	27	28

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

Revenues and EBITDA for the three and nine months ended September 30, 2012 were consistent with the same periods of the prior year. A planned outage at Miller Creek in May 2012 and forced outages in the third quarter of 2012 resulted in lower availability and revenues and increased maintenance costs. These were offset by higher revenues and EBITDA at Brown Lake and Kingsbridge due to higher water and wind volumes respectively. Lower generation for the three and nine months ended September 30, 2012 was primarily due to lower generation from Miller Creek due to the May 2012 planned outage. Island Generation also experienced lower generation for the nine months ended September 30, 2012 compared to the same periods in 2011. However, this had little impact on revenues and EBITDA because, under the terms of the Island Generation agreement, revenues are based on deemed generation which is determined based on the plant's availability. Deemed generation was consistent in the three and nine months ended September 30, 2012 compared to the same periods in 2011.

North East U.S. commercial plants and portfolio optimization

North East U.S. commercial plants [1]	Three months ended September 30		Nine months ended September 30	
	2012	2011	2012	2011
Electricity generation (GWh)	1,550	1,464	3,620	2,466
Availability (%)	97	96	84	97
Revenues (unaudited, $ millions)	62	71	155	122
EBITDA (unaudited, $ millions) [2]	12	10	26	20

(1) North East U.S. commercial plants comprises the Bridgeport and the Rumford and Tiverton facilities as of their dates of acquisition of April 28, 2011 and April 29, 2011, respectively.

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

Lower revenues for the three months ended September 30, 2012 compared with the same period of the prior year reflected lower market spark spreads at the Bridgeport and Tiverton facilities. Higher EBITDA for the three months ended September 30, 2012 compared with the same period in 2011 reflects lower maintenance costs since there was a scheduled outage at Bridgeport in the third quarter of 2011 and no similar outage in the third quarter of 2012. This increase in EBITDA was partly offset by higher losses on portfolio optimization activities.

Revenues and EBITDA for the nine months ended September 30, 2012 were further unfavourably impacted by an unplanned outage at the Bridgeport facility which was offline from May 2 to June 11, 2012 due to a condenser leak. The Company incurred $2 million in maintenance costs and lost an estimated $4 million in revenues as a result of this outage. Lower market spark spreads reflected the impact of lower natural gas prices resulting primarily from an oversupply of natural gas. The unfavourable impacts of lower market prices, losses from portfolio optimization activities and unplanned outages were more than offset in the nine months ended September 30, 2012 with three full quarters of operations compared with the corresponding period of 2011 which only reflected operations since the acquisition of the plants in late April 2011.

North Carolina U.S. contracted plants

North Carolina U.S contracted plants [1]	Three months ended September 30		Nine months ended September 30	
	2012	2011	2012	2011
Electricity generation (GWh)	175	n/a	509	n/a
Availability (%)	99	n/a	94	n/a
Revenues (unaudited, $ millions)	19	n/a	55	n/a
EBITDA (unaudited, $ millions) [2]	-	n/a	2	n/a

(1) North Carolina U. S. contracted plants comprises the Roxboro and Southport facilities as of their date of acquisition of November 5, 2011.

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

For the three and nine months ended September 30, 2012, the performance of the North Carolina U.S. contracted plants was lower than expected primarily due to lower energy margins based on lower than expected heat rates and higher maintenance and fuel costs compared with the costs in the same period of the prior year when these plants were owned and operated by CPILP. Maintenance costs in 2012 reflected planned spring outages at both Southport and Roxboro. Both outages took longer than expected which resulted in higher than anticipated maintenance costs. Southport's fuel costs for the three months ended September 30, 2012 included approximately $1 million for unanticipated adjustments related to physical fuel coal inventory and Roxboro's maintenance costs for the same period included $1 million for reclassification from capital to operating.

CPILP plants

CPILP plants	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
Electricity generation (GWh)	n/a	1,294	n/a	3,588
Availability (%)	n/a	96	n/a	92
Revenues (unaudited, $ millions)	n/a	139	n/a	396
EBITDA (unaudited, $ millions) (1)	n/a	48	n/a	129

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

The Company divested its limited partnership units of CPILP in November 2011.

Other portfolio activities

Other portfolio activities	Three months ended September 30		Nine months ended September 30	
	2012	2011	2012	2011
Revenues (unaudited, $ millions)	10	19	43	71
EBITDA (unaudited, $ millions) (1)	4	-	11	2

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

Lower revenues for the three and nine months ended September 30, 2012 compared with the same periods in 2011 were primarily due to the termination of the manager contracts associated with the Company's former interest in CPILP and lower natural gas sales. For the three and nine months ended September 30, 2012 compared with the corresponding periods of 2011, lower revenues were partly offset by higher revenues for emission credit sales.

EBITDA increased in the three and nine months ended September 30, 2012 primarily due to natural gas trading gains. The increase in EBITDA for the nine months ended September 30, 2012 compared with the same period in 2011 was further impacted by a gain related to a change in the provision for estimated future losses on certain natural gas retail contracts. The revised estimate for the provision was based on a decrease in forward natural gas prices in 2012. North American forward gas prices have been decreasing primarily due to decreased demand and oversupply. The increase in EBITDA in the nine months ended September 30, 2012 compared with 2011 is partly offset by increased emission credit costs in 2012.

Corporate

Corporate	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
Revenues (unaudited, $ millions)	5	5	21	17
EBITDA (unaudited, $ millions) (1)	(30)	(28)	(83)	(79)

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

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

EBITDA for the three and nine months ended September 30, 2012 reflected increased compensation costs resulting from performance in relation to the Company's target performance metrics and recruitment for previously vacant positions and increased costs related to the Company's corporate head office move in September 2011. In the three and nine months' periods, these increased costs were partly offset by reduced legal costs and an unfavourable pension adjustment in 2011. Higher 2011 legal costs primarily related to the CPILP divestiture and the acquisition of the New England plants. The unfavourable pension adjustment in 2011 was based on an actuarial valuation of the Company's supplemental pension plan obligation which incorporated refinements to estimates made at the time of the Company's spinoff from EPCOR. Corporate results for the nine months ended September 30, 2012 included the first quarter realized gain on the sale of Atlantic Power shares.

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

Unrealized changes in fair value of energy and foreign exchange derivative instruments and Atlantic Power shares	Three months ended September 30		Nine months ended September 30	
	2012	2011	2012	2011
Revenues (unaudited, $ millions)	18	(28)	21	(81)
EBITDA (unaudited, $ millions) [1]	7	(28)	12	(58)

[1] The financial results by plant category, except for 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 and foreign exchange 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 EBITDA for the appropriate plant portfolio optimization or Corporate category.

For the three months ended September 30, 2012, Alberta desk electricity portfolio activities resulted in an unrealized net gain of $6 million compared with a $1 million loss in the corresponding period of 2011. For the nine months ended September 30, 2012, Alberta desk electricity portfolio activities accounted for an unrealized net gain of $12 million compared with an unrealized net loss of $42 million for the same period in 2011. The unrealized gain in the three and nine months ended September 30, 2012 primarily reflected the impact of decreases in Alberta forward power prices on the portfolio positions and the reversal of previously recognized unrealized net losses on contracts which settled in the first nine months of 2012. The unrealized net loss for the third quarter of 2011 primarily reflected the impact of increases in Alberta forward power prices on the portfolio position partly offset by the reversal of an unrealized net loss accrued at June 30, 2011 on contracts which settled in the third quarter of 2011. The unrealized net loss for the nine months ended September 30, 2011 primarily reflected the reversal of an unrealized net gain accrued at December 31, 2010 on contracts which settled in the first nine months of 2011, and the impact of increases in Alberta forward power prices on the portfolio position.

Upon acquisition of the New England plants in the second quarter of 2011, the Company acquired electricity heat rate options related to the Bridgeport and Tiverton facilities. The Tiverton heat rate options subsequently expired in 2011. For the three and nine months ended September 30, 2012, the Company recognized an unrealized gain of $3 million and $4 million, respectively, related to its Bridgeport heat rate options. These gains primarily reflected the reversal of unrealized losses which were accrued at June 30, 2012 and December 31, 2011, respectively on contracts that settled in the corresponding periods, For the three and nine months ended September 30, 2011, the Company recognized an unrealized loss of $4 million and an unrealized gain of $1 million respectively on the heat rate options related to the Bridgeport and Tiverton facilities. These amounts included unrealized losses for decreases in the fair value of the options resulting from changes in the underlying forward market prices for power and natural gas, offset by the reversal of unrealized losses accrued at June 30, 2011 and at acquisition, on contracts that settled in the corresponding periods.

Unrealized gains from the Company's Alberta and New England portfolios for the nine months ended September 30, 2012 were partly offset by the reversal of a $5 million unrealized gain on the Atlantic Power shares which was recorded in the fourth quarter of 2011. This gain was reversed in the first quarter of 2012 as these shares were sold resulting in a realized gain of $4 million included in the Corporate category.

The Company divested its limited partnership units of CPILP in November 2011. The divestiture was the primary reason for higher revenues and EBITDA related to unrealized changes in the fair value of derivative instruments for the three and nine months ended September 30, 2012. For the three months and nine months ended September 30, 2011, CPILP's revenues included net losses of $23 million and $19 million respectively, for changes in the fair value of foreign exchange contracts. These changes in fair value were primarily due to an increase in the forward prices for U.S. dollars relative to Canadian dollars of $0.077 in the three months ended September 30, 2011 and $0.048 in the nine months ended September 30, 2011.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $ millions)	Three months ended September 30		Nine months ended September 30	
	2012	2011	2012	2011
Reversal of previously recognized unrealized losses representing changes in the fair value of forward bond sale contracts	-	(4)	8	2
Other finance expense	(19)	(28)	(62)	(78)
Total finance expense	(19)	(32)	(54)	(76)
Foreign exchange loss	-	(7)	-	(13)
Depreciation and amortization	(52)	(45)	(159)	(167)
Impairments	-	-	(74)	(43)
Income tax expense	(18)	(11)	(10)	-
Net income attributable to non-controlling interests	24	29	24	43

Finance expense

Finance expense included the reversal of previously recognized unrealized decreases in the fair value of forward bond contracts of $8 million for the nine months ended September 30, 2012 and $2 million in the same period of the prior year. These reversals decreased finance expense and increased net income but were offset by the realized losses of $7 million and $12 million (for the nine months ended September 30, 2012 and 2011, respectively) recognized on the settlement of these contracts and which were included in other finance expense. These contracts economically hedged the Company's exposure to interest rate risk on anticipated debt issues. While these contracts settled at a loss, future interest payments on the debt were and will be incurred at a rate lower than the rate that was locked in by the hedge.

Finance expense for the three months and the nine months ended September 30, 2012 decreased compared with the same periods in the prior year since there was no finance expense related to CPILP subsequent to its disposal in November 2011.

Foreign exchange losses

Foreign exchange losses were $nil for the three and nine months ended September 30, 2012 since no material foreign exchange contracts settled in these periods. For the three months and the nine months ended September 30, 2011, foreign exchange losses of $7 million and $13 million consisted of losses on foreign exchange contracts entered into in anticipation of U.S. cash payments related to the acquisition of the New England facilities.

Depreciation and amortization

Depreciation and amortization increased $7 million for the three months ended September 30, 2012 compared with the same period in the prior year due to increased depreciation and amortization on the North Carolina plants acquired in the fourth quarter of 2011 and the addition of Keephills 3 which went into service September 1, 2011. These increases were partly offset by decreased depreciation and amortization on CPILP assets due to their disposal in November 2011. Decreases in depreciation and amortization from the CPILP assets more than offset increased depreciation and amortization related to the additions of the North East U.S. commercial plants, Keephills 3 and the North Carolina plants in the second, third and fourth quarter of 2011 respectively resulting in decreased depreciation of $8 million for the nine months ended September 30, 2012 compared with the same period in the prior year.

Impairments

Impairments, on a pre-tax basis, were $74 million for the nine months ended September 30, 2012 compared to $43 million in the comparative period. 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 to the expected operating margins were largely the result of weaker spark spreads in the New England power market. See Significant Events. In the second quarter of 2011, an asset impairment loss of $43 million was recognized related to the CPILP management and operations contracts.

Income tax expense

Income tax expense increased $7 million and $10 million respectively for the three and nine months ended September 30, 2012 compared with the same periods in the prior year due to higher pre-tax income while the increased ownership percentage in CPLP further contributed to the increased income tax expense.

Non-controlling interests

For the nine months ended September 30, 2012, approximately 32% (2011 – 51%) of CPLP's net income was attributable to EPCOR which is reported as net income attributable to non-controlling interests by the Company. Net income attributable to non-controlling interests also included the Genesee coal mine partner's share of the consolidated depreciation of coal costs. EPCOR's April 5, 2012 exchange of exchangeable common limited partnership units for common shares of Capital Power (see Significant Events) reduced its interest in CPLP to 29% from 39% which will reduce the proportion of net income attributable to non-controlling interests reported by the Company in future periods.

For the three months and the nine months ended September 30, 2011, approximately 29% of CPILP's net income was included in CPLP's income with the remaining 71% attributable to non-controlling interests. Therefore, the net income attributable to non-controlling interests in CPLP included approximately 15% (51% of 29%) of CPILP net income for first three quarters of 2011. There are no comparable figures for 2012 because the Company disposed of its interest in CPILP in November 2011.

Other Comprehensive Income

For the three months ended September 30, 2012, after-tax net unrealized gains on derivative instruments designated as cash flow hedges (for the effective portion) of $31 million compared with after-tax net unrealized losses of $16 million for the same period in 2011 were recorded in other comprehensive income. After-tax net realized losses of $3 million and $23 million for the three months ended September 30, 2012 and September 30, 2011 respectively were reclassified to revenues and energy purchases and fuel, as appropriate. Other comprehensive income also included after-tax unrealized losses of $15 million for the three months ended September 30, 2012 compared with after-tax unrealized gains of $78 million in the same period of 2011 representing foreign exchange differences on the translation of foreign operations. For the three months ended September 30, 2011, other comprehensive income also included after-tax unrealized losses of $4 million on available-for-sale financial assets.

For the nine months ended September 30, 2012, after-tax net unrealized gains on derivative instruments designated as cash flow hedges (for the effective portion) of $68 million compared with after-tax net unrealized losses of $90 million for the same period in 2011 were recorded in other comprehensive income. After-tax net realized gains of $22 million for the nine months ended September 30, 2012 and losses of $39 million for the nine months ended September 30, 2011 were reclassified to revenues and energy purchases and fuel, as appropriate. After-tax actuarial losses related to the Company's defined benefit pension plans of $3 million were recorded in the nine months ended September 30, 2012 with no actuarial gains or losses recorded in the comparative periods. Foreign exchange differences on the translation of foreign operations resulted in after-tax unrealized losses of $15 million and after-tax unrealized gains of $70 million for the nine months ended September 30, 2012 and September 30, 2011 respectively. For the nine months ended September 30, 2011, other comprehensive income also included after-tax unrealized losses of $3 million representing losses on available-for-sale financial assets.

Financial Position

The significant changes in the Consolidated Statements of Financial Position from December 31, 2011 to September 30, 2012 were as follows:

(unaudited, $ millions)

	September 30, 2012	December 31, 2011	Increase (decrease)	Explanation of increase (decrease)
Trade and other receivables	327	198	129	Primarily due to the timing of the settlement of and an increase in the sales receivable from the Alberta Electric System Operator resulting from higher power prices in September 2012 compared with December 2011 and increased sales receivable related to Genesee 3 which experienced a forced outage in December 2011.
Other financial assets – current	-	53	(53)	Sold Atlantic Power Corporation shares.
Assets classified as held for sale	61	-	61	Represents the Brown Lake and Miller Creek hydro facilities.
Net derivative financial instruments assets (liabilities)	45	(36)	81	Primarily due to increases in the fair value of derivative power contracts resulting from decreasing Alberta forward power prices.
Property, plant and equipment	3,984	3,842	142	Primarily due to capital expenditures (most significantly, the Quality Wind and Halkirk projects) partly offset by depreciation.
Trade and other payables	286	220	66	Primarily due to the timing of the settlement of billings related to Sundance and higher accruals related to the Halkirk wind project.
Liabilities classified as held for sale	8	-	8	Represents the Brown Lake and Miller Creek hydro facilities.
Loans and borrowings (including current portion)	1,665	1,480	185	$250 million debt issue partly offset by repayment of loans and borrowings.
Share capital	1,750	1,499	251	Common shares issued.
Non-controlling interests	833	1,072	(239)	Conversion of common limited partnership units of CPLP to common shares of Capital Power by EPCOR in April 2012 and distributions offset by earnings attributable to non-controlling interests.

Liquidity and Capital Resources

(unaudited, $ millions)	Nine months ended September 30		
Cash inflows (outflows)	**2012**	**2011**	**Increase (decrease)**
Operating activities	213	310	(97)
Investing activities	(350)	(937)	587
Financing activities	100	670	(570)

Operating activities

Cash flows from operating activities for year-to-date 2012 decreased compared with year-to-date 2011 primarily due to the disposal of CPILP which reduced cash inflows and increases in trade and other receivables and trade and other payables due to the timing of settlement of certain accounts..

Investing activities

The cash flows used in investing activities for the nine months ended September 30, 2012 included $433 million for capital expenditures (most significantly, the Quality Wind and Halkirk projects) partly offset by $52 million of proceeds received on the sale of shares in Atlantic Power. Business acquisitions, including the New England facilities, in the nine months ended September 30, 2011 significantly contributed to the year-over-year decrease in cash flows used in investing activities.

Financing activities

The cash flows from financing activities during the nine months ended September 30, 2012 primarily reflected proceeds from the $250 million CPLP debt offering in February 2012 partly offset by debt repayments of $52 million and distributions and dividends paid of $96 million.

As at September 30, 2012, a total of $869 million remained available under CPLP's committed credit facilities of $1,200 million. Utilization consisted of approximately $189 million in letters of credit outstanding and $142 million in bankers' acceptances outstanding. In addition, demand facilities of $20 million for CPLP and $5 million for Capital Power Corporation were available. In July 2012, the committed credit facilities were amended to include an accordion feature to increase the facility size by $300 million in the future, subject to certain conditions including lender approval.

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

Capital expenditures

(unaudited, $ millions)	Nine months ended September 30, 2012	Total project: Incurred to September 30, 2012 [1]	Total project: Total cost estimate [2]	Expected completion date
Quality Wind	224	379	400 to 415	4th quarter 2012
Halkirk	105	288	357	4th quarter 2012
Port Dover & Nanticoke	5	54	340	4th quarter 2013
K2	2	2	874	2014
Sustaining – plant maintenance and other	65			
Sustaining – Genesee mine lands	17			
Total capital expenditures [3]	**418**			
Emission credits	34			
Capitalized interest	(19)			
Net payments to acquire property, plant and equipment and other assets	**433**			

(1) Total project capital expenditures incurred to September 30, 2012 reflect capital expenditures incurred since the inception of the project.

(2) Capital expenditures to be incurred over the life of the project are based on management's estimates.

(3) Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the Statement of Cash Flows as payments to acquire property, plant and equipment and other assets.

Sustaining capital expenditures include spending on plant maintenance, the Genesee mine, and information technology consisting of an enterprise resource planning redesign and a new energy trading and risk management system.

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 2012 are expected to include approximately $592 million for capital expenditures, approximately $42 million for CPLP distributions to EPCOR (subject to approval by the Board of Directors of CPLP's general partner), approximately $63 million for Capital Power's common share dividends, and approximately $6 million for quarterly preferred share dividends (subject to approval by Capital Power Corporation's Board of Directors). 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 initial participation rate in the Dividend Re-investment Plan was approximately 30% for the Company's second quarter 2012 dividend and depending on the participation rate for the balance of the year, cash requirements for common share dividends may differ from the above expectations.

The Company expects to fund the construction of the Quality Wind, Port Dover & Nanticoke and Halkirk wind projects from cash flows from operating activities and using existing bank credit facilities. 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, use of existing bank credit facilities, proceeds from the sale of hydro facilities, and proceeds from the February 2012 sale of Atlantic Power shares.

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 for a major investment. 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 $1.8 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.

Contractual Obligations

The only material change to the Company's commitments since December 31, 2011 was the February 21, 2012 issuance of $250 million of unsecured medium-term notes payable. As a result of this debt issue, the Company's debt repayment and interest payment obligations in the current and future years will increase. There were no other changes to the Company's purchase obligations and commitments since December 31, 2011 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, 2011 MD&A.

Off-Statement of Financial Position Arrangements

As at September 30, 2012, management of the Company does not believe they have any off-statement of financial position arrangements that have, or are reasonably likely to have, a current or future material effect on the Company's financial condition, results of operations, liquidity, capital expenditures or resources.

Transactions with Related Parties

(unaudited, $ millions)	Note	Three months ended September 30		Nine months ended September 30	
		2012	2011	2012	2011
EPCOR (shareholder)					
CPLP distributions paid	(a)	9	15	33	45
Purchase of distribution and transmission services	(b)	6	6	16	16
Purchase of other services	(b)	2	1	6	5
Power sales	(b)	3	2	7	236
Interest incurred on unsecured senior debt payable and expensed	(c)	4	9	15	20
Interest incurred on unsecured senior debt payable and capitalized	(c)	2	1	4	11
Repayment of unsecured senior debt payable	(c)	25	-	25	33
The City of Edmonton (sole shareholder of EPCOR)					
Power sales	(b)	9	8	27	25

	Note	As at September 30, 2012	As at December 31, 2011
EPCOR (shareholder)			
Trade and other receivables	(b)	2	1
Trade and other payables	(b)	14	22
Provision for future maintenance costs associated with EPCOR's Rossdale plant	(d)	7	7
Loans and borrowings	(c)	357	382
The City of Edmonton (sole shareholder of EPCOR)			
Trade and other receivables	(b)	6	7

(a) As at September 30, 2012, EPCOR owned 28.441 million exchangeable common limited partnership units of CPLP, and 28.441 million accompanying special voting shares and one special limited voting share in the capital of Capital Power Corporation. As at December, 31, 2011, EPCOR owned 38.216 million exchangeable common limited partnership units of CPLP, and 38.216 million accompanying special voting shares and one special limited voting share in the capital of Capital Power Corporation. In connection with EPCOR's unit holdings, CPLP paid distributions to EPCOR for the three months and the nine months ended September 30, 2012 and 2011.

(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 the 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. On or after December 2, 2012, if EPCOR no longer owns, directly or indirectly, at least 20% of the outstanding common limited partnership units of CPLP, then EPCOR may, by written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon. Refer to Liquidity and Capital Resources section in the Company's 2011 annual MD&A for discussion of repayment obligation.

(d) The Rossdale plant, which is owned by EPCOR, was taken out of service in January 2009 and is to be 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

There have been no material changes in the nine months ended September 30, 2012 to the Company's business and operational risks as described in the Company's December 31, 2011 MD&A.

Environmental Matters

The Company has recorded decommissioning provisions of $176 million as at September 30, 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 $71 million in the current and future years and expects to use these credits to comply with certain environmental regulations.

On April 23, 2012, Capital Power and its partners of TransAlta, Enbridge Inc. and the federal and provincial governments decided not to proceed with their carbon capture and storage project following an extensive engineering and design study. While the project proved to be technically feasible, the economics of the project did not support a decision to proceed.

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.

With the exception of the impairment of the North East U.S. assets (see Significant Events), there have been no significant changes to the Company's critical accounting estimates and accounting judgments as described in the Company's December 31, 2011 MD&A.

Future Accounting Changes

Apart from the new and amended accounting standards that will be effective in future periods as discussed in the Company's 2011 MD&A, there were no changes to future accounting standards that occurred during the nine months ended September 30, 2012 that will materially affect or are reasonably likely to materially affect the Company's financial statements.

Financial Instruments

Risk management and hedging activities

There have been no material changes in the nine months ended September 30, 2012 to the Company's risk management and hedging activities as described in the Company's December 31, 2011 MD&A.

The derivative instruments assets and liabilities held at September 30, 2012 compared with December 31, 2011 and used for risk management purposes were measured at fair value and consisted of the following:

($ millions)	Energy cash flow hedges	Energy non-hedges	Interest rate non-hedges	Total
Derivative instruments net assets (liabilities) at September 30, 2012	33	12	-	45
Derivative instruments net assets (liabilities) at December 31, 2011	(23)	(5)	(8)	(36)

Energy derivatives designated as accounting hedges

As at September 30, 2012, the fair value of the energy derivative instruments designated and qualifying for hedge accounting was a net asset of $33 million, an increase from the net liability of $23 million at December 31, 2011. The increase in the net asset primarily reflects the impact of forward Alberta power prices on power derivative contracts relative to the contract prices. Unrealized gains and losses for fair value changes on 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, 2012, the fair value of energy derivative instruments not designated as hedges for accounting purposes was a net asset of $12 million as compared with a net liability of $5 million at December 31, 2011. 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 energy derivative instruments that do not qualify for hedge accounting are recorded in revenues or energy purchases and fuel as appropriate.

As at September 30, 2012, the Company did not have any forward bond sale contracts. As at December 31, 2011, the fair value of the Company's two $100 million forward bond sale contracts was a derivative instrument liability of $8 million. The unrealized changes in the fair value of these contracts and reversals of these changes were recognized in finance expense as discussed under Consolidated Other Expenses and Non-controlling Interests.

As at September 30, 2012 and December 31, 2011, the Company did not have any forward foreign currency contracts outstanding since these contracts were primarily used to economically hedge U.S. dollar denominated revenues and expected future net U.S. dollar cash flows from CPILP's U.S. plants. These contracts are no longer being used since the Company disposed of its interest in CPILP in November 2011. 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.

Disclosure Controls and Procedures and Internal Control over Financial Reporting

There were no changes in the Company's disclosure controls and procedures and internal controls over financial reporting that occurred during the nine months ended September 30, 2012 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting and disclosures of required information.

Summary of Quarterly Results

(GWh)	Three months ended							
Electricity generation	**Sep 30 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**
Total generation excluding acquired Sundance PPA and CPILP plants	4,575	3,499	4,222	3,780	4,221	3,207	2,451	2,556
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	507	453	399	222	496	477	482	272
Keephills 3	489	473	430	485	336	50	-	-
Joffre	87	97	92	104	90	57	98	82
Clover Bar Energy Centre 1, 2 and 3	130	140	27	132	57	40	162	179
Taylor Coulee Chute	n/a	n/a	n/a	2	12	2	-	1
Clover Bar Landfill Gas	8	9	8	7	9	9	8	9
Alberta commercial plants – owned	1,221	1,172	956	952	1,000	635	750	543
Acquired Sundance PPA	738	660	695	596	545	701	758	749
	1,959	1,832	1,651	1,548	1,545	1,336	1,508	1,292
Alberta contracted plants								
Genesee 1	755	767	814	855	843	661	768	854
Genesee 2	815	589	843	849	845	789	831	826
	1,570	1,356	1,657	1,704	1,688	1,450	1,599	1,680
Ontario and British Columbia contracted plants								
Kingsbridge 1	15	22	37	35	12	24	31	39
Miller Creek	22	16	4	8	49	26	5	7
Brown Lake	14	16	15	14	8	15	14	14
Island Generation	8	-	66	1	-	55	52	273
	59	54	122	58	69	120	102	333
North East U.S. commercial plants								
Bridgeport	905	300	844	499	872	645	n/a	n/a
Rumford	229	87	33	83	170	68	n/a	n/a
Tiverton	416	354	452	389	422	289	n/a	n/a
	1,550	741	1,329	971	1,464	1,002	n/a	n/a
North Carolina U.S. contracted plants								
Roxboro	64	61	55	36	n/a	n/a	n/a	n/a
Southport	111	115	103	59	n/a	n/a	n/a	n/a
	175	176	158	95	n/a	n/a	n/a	n/a
CPILP plants	n/a	n/a	n/a	427	1,294	1,155	1,139	1,311

Plant availability	Three months ended							
	Sep 30 2012	Jun 30 2012	Mar 31 2012	Dec 31 2011	Sep 30 2011	Jun 30 2011	Mar 31 2011	Dec 31 2010
Total average plant availability excluding acquired Sundance PPA and CPILP plants	97%	81%	97%	87%	97%	91%	93%	91%
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	100%	95%	84%	44%	100%	100%	100%	56%
Keephills 3	100%	100%	95%	99%	100%	n/a	n/a	n/a
Joffre	98%	99%	94%	93%	99%	78%	99%	99%
Clover Bar Energy Centre 1, 2 and 3	97%	97%	98%	99%	91%	65%	54%	95%
Taylor Coulee Chute	n/a	n/a	n/a	100%	100%	94%	100%	100%
Clover Bar Landfill Gas	92%	86%	95%	77%	86%	86%	95%	88%
Alberta commercial plants – owned	99%	98%	93%	84%	97%	82%	87%	83%
Acquired Sundance PPA	97%	90%	95%	81%	72%	91%	98%	95%
	98%	96%	93%	83%	89%	84%	91%	87%
Alberta contracted plants								
Genesee 1	93%	97%	97%	100%	100%	81%	92%	100%
Genesee 2	99%	72%	100%	100%	100%	99%	100%	97%
	96%	85%	98%	100%	100%	90%	96%	98%
Ontario and British Columbia contracted plants								
Kingsbridge 1	99%	99%	99%	98%	99%	99%	98%	100%
Miller Creek	71%	38%	85%	78%	92%	99%	78%	12%
Brown Lake	99%	100%	99%	93%	53%	99%	100%	99%
Island Generation	100%	100%	100%	100%	100%	100%	99%	99%
	97%	94%	98%	98%	98%	100%	97%	91%
North East U.S. commercial plants								
Bridgeport	95%	35%	96%	59%	96%	100%	n/a	n/a
Rumford	97%	84%	98%	94%	95%	99%	n/a	n/a
Tiverton	99%	77%	100%	89%	97%	100%	n/a	n/a
	97%	58%	98%	76%	96%	99%	n/a	n/a
North Carolina U.S. contracted plants								
Roxboro	97%	84%	96%	100%	n/a	n/a	n/a	n/a
Southport	100%	87%	96%	100%	n/a	n/a	n/a	n/a
	99%	86%	96%	100%	n/a	n/a	n/a	n/a
CPILP plants	n/a	n/a	n/a	96%	96%	88%	92%	95%

Financial results

(unaudited, $ millions)	Three months ended							
	Sep 30 2012	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**
Revenues and other income								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	207	141	180	168	144	215	266	236
Alberta contracted plants	69	63	75	86	87	64	77	75
Ontario and British Columbia contracted plants	12	12	14	13	12	13	13	12
North East U.S. commercial plants and portfolio optimization	62	34	59	51	71	51	-	-
North Carolina U.S. contracted plants	19	18	18	14	-	-	-	-
CPILP plants	-	-	-	51	139	129	128	140
Other portfolio activities	10	4	29	21	19	18	34	21
Corporate	5	7	9	5	5	6	6	6
Interplant category transaction eliminations	(8)	(7)	(18)	(11)	(16)	(17)	(20)	(16)
	376	272	366	398	461	479	504	474
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments	18	(11)	14	-	(5)	(8)	(49)	(50)
Unrealized changes in fair value of CPILP's foreign exchange contracts	-	-	-	9	(23)	1	3	11
	18	(11)	14	9	(28)	(7)	(46)	(39)
	394	261	380	407	433	472	458	435
EBITDA								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization	113	55	87	70	72	44	38	43
Alberta contracted plants	38	35	45	51	57	35	47	40
Ontario and British Columbia contracted plants	8	9	10	10	8	10	10	7
North East U.S. commercial plants and portfolio optimization)	12	1	13	6	10	10	-	-
North Carolina U.S. contracted plant	-	-	2	4	-	-	-	-
CPILP plants	-	-	-	19	48	37	44	36
Other portfolio activities	4	-	7	6	-	2	-	(6)
Corporate	(30)	(28)	(25)	(26)	(28)	(28)	(23)	(29)
Interplant category transaction eliminations	-	-	-	-	-	-	-	(1)
	145	72	139	140	167	110	116	90
Unrealized changes in fair value of CPLP's energy and foreign exchange derivative instruments	7	(8)	13	-	(5)	-	(34)	(12)
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	-	-	-	10	(23)	2	2	13
	7	(8)	13	10	(28)	2	(32)	1
	152	64	152	150	139	112	84	91

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 and natural gas, foreign exchange and forward bond sale contracts.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Sep 30 2012	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**
Revenues and other income	394	261	380	407	433	472	458	435
EBITDA[1]	152	64	152	150	139	112	84	91
Net income (loss)	63	(58)	66	152	44	(22)	14	22
Net income (loss) attributable to shareholders of the Company	39	(32)	40	84	15	(25)	3	(3)
Earnings (loss) per share ($)	0.55	(0.50)	0.66	1.47	0.29	(0.67)	0.06	(0.13)
Normalized earnings per share ($) [1]	0.55	0.07	0.46	0.36	0.43	0.07	0.34	0.21

(1) The consolidated financial information, except for 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 2012**	**Jun 30 2012**	**Mar 31 2012**	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**
Alberta power ($/MWh)	78	40	60	76	95	52	82	46
New England mass hub (US$/MWh)	37	29	33	38	47	43	n/a	n/a
Alberta natural gas (AECO) ($/Gj)	2.16	1.80	2.06	3.03	3.47	3.68	3.57	3.79
Capital Power's Alberta portfolio's average realized power price ($/MWh)	81	60	83	75	74	56	64	64

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 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.

In the third quarter of 2011, the average Alberta power price increased significantly due to warmer temperatures, reduced supply resulting from several plant outages in the area, and Saskatchewan tie-line restrictions. Higher Alberta power prices had a favourable impact on the Company's Alberta portfolio position. Sundance Unit 6 went offline on August 18, 2011 due to a transformer failure and remained offline until October 14, 2011 to also perform planned maintenance. The penalty revenues received for this outage were based on high rolling average power prices partly offset the loss of margin from the facility being unavailable on the Alberta commercial plant and portfolio optimization results. The high rolling average power prices also had a favourable impact on availability incentive income for the Alberta contracted plants which had 100% availability in the quarter. Corporate results included a $6 million foreign exchange loss related to the translation of U.S. denominated debt.

In the second quarter of 2011, North East U.S. commercial plants and portfolio optimization results reflected contributions from the Bridgeport, Rumford and Tiverton facilities and trading in the North East U.S. power market since the acquisition of these plants in April 2011. Alberta contracted plants results included $5 million of availability incentive penalties relating to a scheduled maintenance outage at Genesee 1. An impairment loss of $43 million on Capital Power's management and operations contracts with CPILP was recorded. Finance expense included a $12 million loss related to the settlement of forward bond sale contracts. Income taxes included the reversal of a provision recorded in the second quarter of 2010 for deferred income taxes associated with the possible sale of the Company's interest in CPILP.

In the first quarter of 2011, the average Alberta power price increased significantly primarily due to colder weather than normal and the shutdown of two large coal plants in the region. The sudden increase in Alberta power prices had an unfavourable impact on the Company's Alberta portfolio position.

In the fourth quarter of 2010, high Alberta spot power prices provided opportunities to dispatch the Alberta commercial peaking and mid-merit plants. This was offset by reduced generation from Genesee 3 due to a 42-day scheduled maintenance outage.

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 2012	Jun 30 2012	Mar 31 2012	Dec 31 2011	Sep 30 2011	Jun 30 2011	Mar 31 2011	Dec 31 2010
Share price ($/common share)								
High	24.53	24.47	25.72	25.78	26.38	28.00	26.44	24.84
Low	20.75	22.48	23.29	22.88	21.50	24.90	22.80	23.25
Close	21.29	23.78	23.49	25.12	25.45	25.00	25.92	23.65
Volume of shares traded (millions)	9.6	10.3	9.0	10.6	7.6	9.5	8.9	3.4

Outstanding share and partnership unit data

As at October 26, 2012, the Company had 69.624 million common shares outstanding, 28.441 million special voting shares outstanding, 5 million Cumulative Rate Reset Preference Shares, Series 1 outstanding 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 26, 2012 were 102.805 million. All of the outstanding special voting shares and the outstanding special limited voting share are held by EPCOR.

As at October 26, 2012, CPLP had 21.750 million general partnership units outstanding, 46.699 million common limited partnership units outstanding and 28.441 million exchangeable common limited partnership units outstanding, which are exchangeable for 28.441 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.

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, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Revenues	$ 392	$ 414	$ 1,009	$ 1,309
Other income	2	19	26	54
Energy purchases and fuel	(162)	(189)	(419)	(735)
Gross income	232	244	616	628
Other raw materials and operating charges	(29)	(43)	(95)	(109)
Staff costs and employee benefits expense	(39)	(40)	(109)	(121)
Depreciation and amortization	(52)	(45)	(159)	(167)
Impairments (note 3)	-	-	(74)	(43)
Other administrative expenses	(12)	(22)	(44)	(63)
Foreign exchange losses	-	(7)	-	(13)
Operating income	100	87	135	112
Finance expense	(19)	(32)	(54)	(76)
Income before tax	81	55	81	36
Income tax expense (note 4)	(18)	(11)	(10)	-
Net income	$ 63	$ 44	$ 71	$ 36
Attributable to:				
Non-controlling interests	$ 24	$ 29	$ 24	$ 43
Shareholders of the Company	$ 39	$ 15	$ 47	$ (7)

Earnings (loss) per share (all from continuing operations attributable to common shareholders of the Company):

	Three months 2012	Three months 2011	Nine months 2012	Nine months 2011
Basic (note 6)	$ 0.55	$ 0.29	$ 0.65	$ (0.27)
Diluted (note 6)	$ 0.55	$ 0.29	$ 0.63	$ (0.27)

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, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Net income	$ 63	$ 44	$ 71	$ 36
Other comprehensive income (loss):				
Available-for-sale assets:				
Unrealized losses on available-for-sale financial assets[1]	-	(4)	-	(3)
Cash flow hedges:				
Unrealized gains (losses) on derivative instruments[2]	31	(16)	68	(92)
Reclassification of (gains) losses on derivative instruments to income for the period[3]	3	23	(22)	39
Reclassification of ineffective portion to income for the period[4]	-	-	-	2
Defined benefit plans:				
Actuarial losses[5]	-	-	(3)	-
Net investment in foreign subsidiaries:				
Unrealized gain (loss)[6]	(15)	78	(15)	70
Other comprehensive income, net of tax	19	81	28	16
Total comprehensive income	$ 82	$ 125	$ 99	$ 52
Attributable to:				
Non-controlling interests	$ 32	$ 86	$ 37	$ 57
Shareholders of the Company	$ 50	$ 39	$ 62	$ (5)

[1] For the three and nine months ended September 30, 2012, net of income tax expenses of nil. For the three and nine months ended September 30, 2011, net of income tax recoveries of $1.

[2] For the three and nine months ended September 30, 2012, net of income tax expenses of $6 and $14 respectively. For the three and nine months ended September 30, 2011, net of income tax recoveries of $2 and $12 respectively.

[3] For the three and nine months ended September 30, 2012, net of reclassification of income tax recoveries of $1 and reclassification of expenses of $4 respectively. For the three and nine months ended September 30, 2011, net of reclassification of income tax recoveries of $3 and $5 respectively.

[4] For the three and nine months ended September 30, 2012, net of reclassification of income tax expenses of nil. For the three and nine months ended September, 2011, net of reclassification of income tax expenses of nil.

[5] For the three and nine months ended September 30, 2012, net of income tax recoveries of nil and $1 respectively. For the three and nine months ended September 30, 2011, net of income tax expenses of nil.

[6] For the three and nine months ended September 30, 2012, net of income tax expenses of nil. For the three and nine months ended September 30, 2011, net of income tax recoveries of $3 and $2 respectively.

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, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 35	$ 73
Trade and other receivables	327	198
Inventories	59	59
Derivative financial instruments assets (note 7)	42	25
Other financial assets	-	53
Assets classified as held for sale (note 5)	61	-
	524	408
Non-current assets:		
Other assets	22	24
Derivative financial instruments assets (note 7)	30	13
Finance lease receivables	56	58
Other financial assets	40	42
Deferred tax assets	44	14
Intangible assets	312	296
Property, plant and equipment (note 3)	3,984	3,842
Goodwill (note 3)	21	46
Total assets	$ 5,033	$ 4,743
Liabilities and equity		
Current liabilities:		
Trade and other payables	$ 286	$ 220
Derivative financial instruments liabilities (note 7)	19	67
Loans and borrowings (note 8)	19	28
Deferred revenue and other liabilities	6	13
Provisions	20	33
Liabilities classified as held for sale (note 5)	8	-
	358	361
Non-current liabilities:		
Derivative financial instruments liabilities (note 7)	8	7
Loans and borrowings (note 8)	1,646	1,452
Deferred revenue and other liabilities	90	76
Deferred tax liabilities	105	55
Provisions	211	197
	2,060	1,787
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 9)	1,750	1,499
Retained earnings	8	16
Other reserves	24	8
Retained earnings and other reserves	32	24
	1,782	1,523
Non-controlling interests	833	1,072
Total equity	2,615	2,595
Total liabilities and equity	$ 5,033	$ 4,743

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 gains (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):									
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)
Defined benefit plan actuarial losses	-	-	-	(4)	-	-	(4)	-	(4)
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	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 (loss). Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income (loss) and the employee benefits reserve.

See accompanying notes to the 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]	Available-for-sale financial assets[1]	Defined benefit plan actuarial gains (losses)[1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2011	$ 820	$ 7	$ (7)	$ 1	$ (2)	$ 6	$ 8	$ 833	$ 1,779	$ 2,612
Net income (loss)	-	-	-	-	-	-	(7)	(7)	43	36
Other comprehensive income (loss):										
Net change in fair value of available-for-sale financial assets	-	-	-	(4)	-	-	-	(4)	-	(4)
Cash flow derivative hedge losses	-	(104)	-	-	-	-	-	(104)	-	(104)
Reclassification of losses to income	-	44	-	-	-	-	-	44	-	44
Reclassification of ineffective portion to income	-	2	-	-	-	-	-	2	-	2
Unrealized gain on foreign currency translation	-	-	68	-	-	-	-	68	-	68
Tax on items recognized directly in equity	-	7	2	1	-	-	-	10	-	10
Attributed to non-controlling interests	-	29	(45)	2	-	-	-	(14)	14	-
Other comprehensive income (loss)	$ -	$ (22)	$ 25	$ (1)	$ -	$ -	$ -	$ 2	$ 14	$ 16
Total comprehensive income (loss)	-	(22)	25	(1)	-	-	(7)	(5)	57	52
Issue of share capital	468	-	-	-	-	(1)	2	469	(2)	467
Transaction costs	(18)	-	-	-	-	-	-	(18)	-	(18)
Deferred taxes	4	(1)	-	-	-	-	(9)	(6)	-	(6)
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	(97)	(97)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	-	9	9
Issue of partnership units	-	-	-	-	-	-	-	-	14	14
Common share dividends (note 9)	-	-	-	-	-	-	(41)	(41)	-	(41)
Preferred share dividends (note 9)	-	-	-	-	-	-	(4)	(4)	-	(4)
Preferred share dividends paid by subsidiary	-	-	-	-	-	-	-	-	(11)	(11)
Share-based payment transactions	-	-	-	-	-	2	-	2	-	2
Equity as at September 30, 2011	$ 1,274	$ (16)	$ 18	$ -	$ (2)	$ 7	$ (51)	$ 1,230	$ 1,749	$ 2,979

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

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Nine months ended September 30, 2012	2011
Cash flows from operating activities:		
Net income	$ 71	$ 36
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	159	167
Impairments (note 3)	74	43
Finance expense	54	76
Fair value changes on derivative instruments	(25)	55
Unrealized foreign exchange losses	-	8
Income tax expense	10	-
Other items	7	9
Interest paid[1]	(37)	(44)
Income taxes paid	(6)	(13)
	307	337
Change in non-cash operating working capital	(94)	(27)
Net cash flows from operating activities	213	310
Cash flows used in investing activities:		
Payments to acquire property, plant and equipment and other assets	(433)	(316)
Proceeds on disposal of other financial assets	52	-
Business acquisitions, net of acquired cash	-	(643)
Other cash flows from investing activities	31	22
Net cash flows used in investing activities	(350)	(937)
Cash flows from financing activities:		
Proceeds from issue of loans and borrowings (note 8)	250	584
Repayment of loans and borrowings	(52)	(192)
Proceeds from issue of common shares	20	468
Share issue costs	-	(18)
Issue costs on loans and borrowings	(3)	(6)
Distributions paid to non-controlling interests	(33)	(83)
Common share dividends paid (note 9)	(59)	(35)
Preferred share dividends paid (note 9)	(4)	(4)
Preferred share dividends paid by subsidiary	-	(11)
Interest paid[1]	(19)	(33)
Net cash flows from financing activities	100	670
Foreign exchange losses on cash held in a foreign currency	(1)	-
Net (decrease) increase in cash and cash equivalents	(38)	43
Cash and cash equivalents at beginning of period	73	56
Cash and cash equivalents at end of period	$ 35	$ 99

[1] Total interest paid.

See accompanying notes to the condensed interim consolidated financial statements

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

1. Reporting entity:

Capital Power Corporation (the Company or Capital Power) 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 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 2011 annual financial statements prepared in accordance with International Financial Reporting Standards.

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, 2011 and have been prepared under the historical cost basis, except for the Company's derivative instruments, cash and cash equivalents, equity investments, 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 31, 2012.

3. Impairment:

During the second quarter of 2012, in conjunction with the Company's long-term forecasting activities, the Company reduced its expected future operating margins for its North East U.S. commercial plants and portfolio optimization cash generating unit (North East U.S. CGU) which includes the Bridgeport, Tiverton and Rumford power generation plants. The reductions to the expected operating margins are largely a result of weakening spark spreads in the New England power market. Spark spreads represent the difference between spot market fuel and power prices and impact the profitability of the Company's North East U.S. plants which sell power into the spot market.

Based upon the above indicator of impairment, the Company tested its North East U.S. CGU for impairment and as a result, recorded $74 million of pre-tax impairments during the second quarter of 2012 within the U.S. geographic area.

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
Property, plant and equipment	$ -	$ -	$ 50	$ -
Goodwill	-	-	24	-
Intangibles	-	-	-	43
Total Impairment	$ -	$ -	$ 74	$ 43

The recoverable amount of the North East U.S. CGU was based on its fair value less costs to sell, calculated using a discounted cash flow method. The calculation of the recoverable amount is most sensitive to the following key assumptions:

- The after-tax discount rates used range from 10.4% to 13.8% 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 North East U.S. CGU. The method and assumptions used to calculate the WACC rate are consistent with the Company's past experience and with previous valuations performed by the Company.

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

3. Impairment, continued:

- The Company has projected cash flows for a period of ten years and used a growth rate of 2% to extrapolate the cash flow projections beyond the ten year period. The growth rate reflects past experience and is consistent with industry practice.
- The Company's cash flow projections include estimates of future electricity and natural gas prices. These estimates incorporate past experience and the Company's current view of future pricing. Consideration is given to externally available information related to future pricing of electricity and natural gas when developing certain pricing assumptions and such external information is used to validate the Company's current view of future pricing. These external sources of information include market information from the independent system operator in the region and information from third party advisory and research firms serving the industry.
- The Connecticut Electric Generation Tax is currently effective through the second quarter of 2013 and the Company's calculations of the recoverable amount for the North East U.S. CGU have assumed that this tax will no longer apply after that time.

4. Income tax:

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Current income tax				
Current income tax (recovery)	$ 1	$ (1)	$ 4	$ -
Deferred income tax				
Adjustments relating to previously unrecognized temporary difference	-	-	-	(7)
Relating to origination and reversal of temporary differences	15	8	17	2
Adjustments in respect of prior periods	2	-	2	-
Relating to changes in tax rates / new taxes	-	2	(13)	-
Relating to write-downs of deferred tax asset	-	2	-	5
Total deferred income tax	17	12	6	-
Income tax expense	$ 18	$ 11	$ 10	$ -

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Income before tax	$ 81	$ 55	$ 81	$ 36
Income tax at the statutory rates of 25.0% and 26.5%, respectively	20	15	20	10
Increase (decrease) resulting from:				
Amounts attributable to non-controlling interests	(2)	(7)	(7)	(8)
Amounts previously not recognized on investments in subsidiaries	-	-	-	(7)
Change in unrecognized tax benefits	-	2	-	5
Non-deductible (taxable) amounts	(2)	1	7	-
Prior period tax adjustments	2	-	2	-
Statutory and other rate differences	-	2	(13)	-
Other	-	(2)	1	-
Income tax expense	$ 18	$ 11	$ 10	$ -

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

5. Assets classified as held for sale:

During the second quarter of 2012, the Company entered into an agreement with a third party pursuant to which the third party would acquire all of the partnership units of the subsidiary of the Company which holds its remaining hydro plant assets, consisting of the Brown Lake and Miller Creek power generation plants (the disposal group), for gross cash proceeds of $69 million less transaction costs of $1 million.

The transaction closed on October 12, 2012, resulting in an approximate pre-tax gain of $11 million, to be recognized in the fourth quarter of 2012. The actual pre-tax gain to be recorded could differ from this estimate as a result of working capital and other post-close purchase price adjustments to be finalized in the fourth quarter of 2012. Upon close of the transaction, $10 million of the gross cash proceeds was paid to a third party escrow agent. These funds will be held in escrow pending the issuance of a new lease, by the Province of British Columbia to the purchaser, in respect of certain lands included in the disposal group. As long as the new lease does not contain variations from the previous lease that significantly impact the economic value of the disposal group, the full amount will be released to the Company.

As at September 30, 2012, the disposal group consisted of assets and liabilities as follows:

		2012
Assets classified as held for sale		
Trade and other receivables	$	1
Intangible assets		4
Property, plant and equipment		56
	$	61
Liabilities classified as held for sale		
Deferred tax liabilities	$	4
Provisions – non-current		4
	$	8

6. Earnings (loss) per share:

Basic earnings (loss) per share

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

	Three months ended September 30,				Nine months ended September 30,			
		2012		2011		2012		2011
Income (loss) for the period attributable to shareholders of the Company	$	39	$	15	$	47	$	(7)
Preferred share dividends of the Company [1]		(1)		(1)		(4)		(4)
Earnings (loss) used in the calculation of basic earnings (loss) per share	$	38	$	14	$	43	$	(11)

[1] Includes preferred share dividends declared in respect of the three and nine months ended September 30, 2012 and 2011 respectively.

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	69,516,691	48,334,251	65,802,931	40,416,559

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

6. Earnings (loss) per share, continued:

Diluted earnings (loss) per share

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

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
Earnings (loss) used in the calculation of basic earnings (loss) per share	$ 38	$ 14	$ 43	$ (11)
Effect of exchangeable limited partnership units issued to EPCOR for common shares [1]	-	-	19	-
Earnings (loss) used in the calculation of diluted earnings (loss) per share	$ 38	$ 14	$ 62	$ (11)

[1] 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 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 Capital Power L.P. (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 and for the three and nine months ended September 30, 2011 the potential exchange of such units for common shares of the Company were not included in the calculation of diluted earnings (loss) per share as they were anti-dilutive.

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

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	69,516,691	48,334,251	65,802,931	40,416,559
Effect of dilutive share purchase options[1]	-	170,308	3,257	-
Effect of exchangeable limited partnership units issued to EPCOR for common shares	-	-	31,865,818	-
Weighted average number of common shares used in the calculation of diluted earnings (loss) per share	69,516,691	48,504,559	97,672,006	40,416,559

[1] 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. For the three and nine months ended September 30, 2011, the average market price of the Company's common shares exceeded the exercise price of certain of the granted share purchase options. For the three months ended September 30, 2011 this resulted in a dilutive effect on earnings (loss) per share. Since the Company recorded a loss for the nine months ended September 30, 2011, the assumed exercise of the stock options decreased the loss per share and as such did not have a dilutive effect on earnings (loss) per share.

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

7. 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, 2012			
	Energy		Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 18	$ 24	$ -	$ 42
Non-current	24	6	-	30
Derivative instruments liabilities:				
Current	(5)	(14)	-	(19)
Non-current	(4)	(4)	-	(8)
Net fair value	$ 33	$ 12	$ -	$ 45
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(3)	-		
Gigajoules of natural gas (millions)	-	25		
Range of contract terms in years	0.1 to 5.3	0.1 to 5.3		

	December 31, 2011			
	Energy		Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 6	$ 19	$ -	$ 25
Non-current	5	8	-	13
Derivative instruments liabilities:				
Current	(30)	(29)	(8)	(67)
Non-current	(4)	(3)	-	(7)
Net fair value	$ (23)	$ (5)	$ (8)	$ (36)
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(3)	(9)		
Gigajoules of natural gas (millions)	-	(2)		
Bond forwards			$ 200	
Range of contract terms in years	0.1 to 5.0	0.1 to 6.0	0.2	

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

7. Derivative financial instruments and hedge accounting, continued:

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

	Three months ended September 30, 2012		Three months ended September 30, 2011	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 41	$ (4)	$ 8	$ (26)
Energy non-hedges	7	(3)	(3)	(2)
Foreign exchange non-hedges	-	-	(23)	1
Interest rate non-hedges	-	-	(4)	-

	Nine months ended September 30, 2012		Nine months ended September 30, 2011	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 56	$ 26	$ (58)	$ (44)
Energy non-hedges	17	31	(36)	(12)
Foreign exchange non-hedges	-	-	(19)	3
Interest rate non-hedges	8	(7)	2	(12)

Realized gains and losses relate only to financial derivative instruments. The following items are included in the Company's statements of income for the three and nine months ended September 30, 2012 and 2011:

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
Revenues	$ 11	$ (64)	$ 99	$ (145)
Energy purchases and fuel	(11)	12	(25)	43
Foreign exchange losses	-	(1)	-	(6)
Finance expense	-	(4)	1	(10)

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, 2012, 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, 2011 – losses of nil and $2 million respectively).

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

	September 30, 2012
Within one year	$ 10
Between 1 – 5 years	15
More than 5 years	-
	$ 25

The Company's cash flow hedges extend up to 2017.

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

8. Loans and borrowings:

On February 21, 2012, the Company's subsidiary, CPLP, issued $250 million of unsecured medium-term notes due in 2019 with interest payable semi-annually at 4.85% commencing on August 21, 2012.

9. Share capital:

Authorized shares

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

Issued, called up and fully paid shares

	September 30, 2012		December 31, 2011	
	Issued	Outstanding	Issued	Outstanding
Common shares	69,623,959	$ 1,628	58,969,007	$ 1,377
Preferred shares, series 1	5,000,000	122	5,000,000	122
Special voting shares	28,441,000	-	38,216,000	-
Special limited voting share	1	-	1	-
		$ 1,750		$ 1,499

On April 5, 2012, a subsidiary of EPCOR exchanged 9,775,000 of their 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 9,775,000 common shares of Capital Power at an offering price of $23.55 per common share for gross proceeds of $230 million. As a result of the unit exchange and share offering, EPCOR's ownership interest in CPLP was reduced to approximately 29.3% (December 31, 2011 – 39.4%).

For the three and nine months ended September 30, 2012, dividends of $22 million and $62 million respectively, or 31.5 cents per share and 94.5 cents per share respectively, have been declared and dividends of $22 million and $59 million respectively, or 31.5 cents per share and 94.5 cents per share respectively, have been paid by the Company to the common shareholders (three and nine months ended September 30, 2011 - $16 million and $41 million respectively, or 31.5 cents per share and 94.5 cents per share respectively, declared and dividends of $13 million and $35 million respectively, or 31.5 cents and 94.5 cents per share respectively, paid). During the three and nine months ended September 30, 2012, dividends of $1 million and $4 million respectively, or 28.8 cents per share and 86.3 cents per share respectively, have been declared and paid by the Company to preferred shareholders (three and nine months ended September 30, 2011 - $1 million and $4 million respectively, or 28.8 cents per share and 90.6 cents per share respectively, declared and paid).

10. 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 5, operate within Canada (British Columbia). 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.

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

10. Segment information, continued:

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

	Three months ended September 30, 2012				Three months ended September 30, 2011			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	$ 307	$ 87	$ -	$ 394	$ 274	$ 159	$ -	$ 433
Revenues and other income – inter-area	8	6	(14)	-	1	-	(1)	-
Total revenues and other income	$ 315	$ 93	$ (14)	$ 394	$ 275	$ 159	$ (1)	$ 433

	Nine months ended September 30, 2012				Nine months ended September 30, 2011			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	$ 783	$ 252	$ -	$1,035	$1,004	$ 359	$ -	$1,363
Revenues and other income – inter-area	14	8	(22)	-	2	1	(3)	-
Total revenues and other income	$ 797	$ 260	$ (22)	$1,035	$1,006	$ 360	$ (3)	$1,363

	As at September 30, 2012			As at December 31, 2011		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,294	$ 690	$ 3,984	$ 3,043	$ 799	$ 3,842
Intangible assets	295	17	312	276	20	296
Goodwill	-	21	21	-	46	46
Other assets	22	-	22	24	-	24
	$ 3,611	$ 728	$ 4,339	$ 3,343	$ 865	$ 4,208