Capital Power Corporation

Capital Power Corporation
5th Floor, TD Tower, 10088 - 102 Avenue
Edmonton, AB T5J 2Z1

For immediate release July 27, 2011

Capital Power reports second quarter 2011 results

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released its results for the quarter ended June 30, 2011. Normalized earnings attributable to common shareholders, after adjusting for one-time items and fair value adjustments was $3 million, or $0.07 per share, in the second quarter of 2011, compared with $1 million, or $0.05 per share, in the comparable period in 2010. Funds from operations, excluding non-controlling interests in Capital Power Income L.P. (CPILP), totaled $65 million in the second quarter of 2011, up 76% from $37 million in the second quarter of 2010. For the six-month period ending June 30, 2011, normalized earnings attributable to common shareholders was $14 million, or $0.38 per share. Funds from operations excluding non-controlling interests in CPILP totaled $147 million compared with $112 million in the six-month period ending June 30, 2010.

"Normalized net income in the second quarter of 2011 was below management's expectation, primarily attributable to a loss on the settlement of forward bond contracts used to economically hedge the U.S. private placement and a larger than expected adjustment to our pension obligation," said Capital Power's President and CEO, Brian Vaasjo. "In addition, the performance of the Alberta Commercial Plants and Portfolio Optimization segment were impacted by lower realized margins due to a lower than expected average Alberta power spot price in the second quarter. This was amplified by outages during a period of high pricing at units of a third-party owned facility where we are the PPA counterparty."

"Our plants performed well in the quarter with average availability, excluding CPILP facilities, of 91%", added Mr. Vaasjo. "Generation volume increased 37% due to the 2010 acquisition of Island Generation and two months inclusion of three recently acquired facilities in the New England area, which also contributed to increased funds from operations in the second quarter of 2011. In addition to the New England acquisitions, the quarter was also highlighted by a number of other important strategic developments including: the first 50 gigawatt hours of power generation from Keephills 3; the acquisition of 100% of the Halkirk I Wind Project in Alberta; and the completion of CPILP's strategic review, under which Capital Power will divest of its approximate 29.2% ownership interest in CPILP and acquire 100% ownership of CPILP's Roxboro and Southport, North Carolina plants. The transaction will result in the termination of the management and operations agreements which are accounted for in the second quarter as an impairment pre-tax loss of $43 million. This will be more than offset in the fourth quarter when the transaction closes with the recognition of $54 million of net income attributable to common shareholders for the gain on sale."

Operational and Financial Highlights[1] (unaudited)	**Three months ended June 30**		**Six months ended June 30**	
(millions of dollars except per share and operational amounts)	**2011**	**2010**	**2011**	**2010**
Electricity generation (GWh)	4,362	3,187	7,952	6,717
Generation plant availability (excluding CPILP plants) (%)	91%	83%	92%	88%
Revenues and other income	472	313	930	814
Gross income	217	117	384	334
Earnings before interest, taxes, depreciation and amortization (EBITDA)[2]	65	37	147	206
Normalized earnings attributable to common shareholders[2]	3	1	14	12
Normalized earnings per share[2]	$0.07	$0.05	$0.38	$0.56
Net income (loss) attributable to shareholders	(25)	(8)	(22)	4
Earnings (loss) per share	$(0.67)	$(0.37)	$(0.69)	$0.18
Dividends declared per share	$0.315	$0.315	$0.63	$0.63
Funds from operations[2]	87	61	190	164
Funds from operations excluding non-controlling interests in CPILP[2]	65	37	147	112
Capital expenditures	120	121	209	183

(1) The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the unaudited Condensed Interim Consolidated Financial Statements for the six months ended June 30, 2011.

(2) Earnings before interest, taxes, depreciation and amortization (EBITDA), Normalized earnings attributable to common shareholders, Normalized earnings per share, Funds from operations, and Funds from operations excluding non-controlling interests in CPILP are non-IFRS financial measures and do not have standardized meanings under IFRS, and therefore, may not be comparable to similar measures used by other enterprises. See Non-IFRS Financial Measures. Reconciliations of these non-IFRS financial measures to Net income attributable to shareholders, Earnings per share and Cash provided by operating activities are included in the Company's Management's Discussion and Analysis dated July 27, 2011, which is available under the Company's profile on SEDAR at www.SEDAR.com.

Significant Events

CPILP strategic review and acquisition of CPILP's Roxboro and Southport facilities

On June 20, 2011, the Company announced that CPILP had entered into an agreement with Atlantic Power Corporation (Atlantic) pursuant to which Atlantic will acquire, directly and indirectly, all of the outstanding limited partnership units of CPILP, including Capital Power's approximate 29.2% ownership interest in CPILP. In connection with the agreement, Capital Power will acquire CPILP's Roxboro and Southport plants in North Carolina for $121 million in cash. Atlantic will acquire CPILP and its remaining eighteen facilities outside North Carolina. The announcement follows the completion of the strategic review process announced by CPILP and Capital Power Corporation in October 2010.

Completion of the transactions is subject to customary closing conditions, including Canadian court approvals, a favourable vote by CPILP unitholders, a favourable vote by the Atlantic shareholders, and the receipt of all necessary regulatory approvals. If the closing conditions are met, the transactions are expected to close in the fourth quarter of 2011, at which time Capital Power will cease to manage CPILP.

Upon closing, Capital Power will receive approximately $320 million in combined consideration for its approximate 29.2% ownership interest in CPILP. The consideration will include cash or stock in Atlantic at Capital Power's election subject to proration, and the cash will be used to fund the acquisition of the North Carolina plants. In addition, the Company's management and operations contracts with CPILP will be terminated or assigned in consideration of payment of an aggregate of $10 million to Capital Power.

The calculation of the gain on disposal of the assets held for sale that will be recognized in income in the fourth quarter of 2011 are based on estimates and carrying amounts as of June 30, 2011 that could change materially by the time the transaction closes.

Acquisition of Halkirk wind project

On May 25, 2011, Capital Power LP (CPLP) acquired 100% of Halkirk I Wind Project LP and Halkirk I Wind Project Ltd from Greengate Power Corporation for $33 million. The assets of the acquired entities were comprised of intangible assets including various permits and land lease rights required to construct the Halkirk Wind Project (Halkirk), and a 20-year power purchase arrangement (PPA) for the sale of renewable energy credits to a third party. Halkirk is a 150-MW wind farm located in east central Alberta, which Capital Power will build, own and operate. All approvals and permits from the Alberta Utilities Commission and Alberta Environment are in place for the facility.

Commercial operation is expected in the last half of 2012 and the total cost of the project, including the $33 million cost of the intangible assets is expected to be approximately $357 million. The project is expected to be, on average, neutral to the Company's annual earnings per share over the first five years of operations. Halkirk will earn revenues from the sale of energy into the Alberta spot market, and from the sale of renewable energy credits under the 20-year fixed-price PPA. Approximately 40% to 45% of Halkirk's revenue is expected to come from the sale of renewable energy credits and the project has a favourable after-tax rate of return over the projected life of its assets.

Halkirk will incorporate 83 turbines to be supplied by Vestas Canadian Wind Technology Inc., the same technology to be used at Capital Power's Quality Wind project in British Columbia and Port Dover & Nanticoke project in Ontario.

Acquisition of three New England power plants

On April 28, 2011, CPLP acquired 100% of the equity interests in Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport), for $344 million (US$362 million) including a working capital adjustment of $6 million (US$7 million). Bridgeport is a natural gas-fired combined cycle power generation plant located in Bridgeport, Connecticut, with a nominal capacity of 520 MW.

On April 29, 2011, CPLP acquired 100% of the equity interests in Tiverton Power Inc. and Rumford Power Inc. (Tiverton and Rumford) which own generating facilities located in Tiverton, Rhode Island and Rumford, Maine respectively. Both plants are natural gas-fired combined cycle power generation facilities serving the New England region in the U.S. Northeast, and have a maximum combined capacity of 549 MW. The purchase price was $299 million (US$315 million).

All three plants are merchant facilities and sell their output into the New England Power Pool (NEPOOL). Their revenues are expected to include payments for capacity, energy, and ancillary services at market-based rates.

$300 million debt offering

On April 18, 2011, CPLP completed a public offering of $300 million unsecured medium-term notes. The notes have a coupon rate of 4.6%, are payable semiannually commencing on June 1, 2011, and mature on December 1, 2015. The net proceeds of the offering were used for general corporate purposes including repayment of amounts owing under credit facilities, short-term investment, financing of ongoing capital projects and working capital requirements.

US$295 million private placement of senior notes

On June 15, 2011, Capital Power U.S. Financing LP, an indirect subsidiary of CPLP, closed a US$295 million private placement of senior notes. The net proceeds from the transaction were primarily used to fund the acquisition of the three New England facilities and for general corporate purposes.

The senior notes consist of two notes with 10-year and 15-year terms. The 10-year senior note has a principal amount of US$230 million that matures in May 2021 with a coupon rate of 5.21%. The 15-year senior note has a US$65 million principal amount and matures in May 2026 with a coupon rate of 5.61%.

Subsequent Event

$231 million common share offering

In July 2011, the Company closed an offering to sell 9,200,000 common shares at a price of $25.10 per share to a syndicate of underwriters for gross proceeds of approximately $231 million, less underwriters' fees of approximately $9 million. The net proceeds from the common share offering were used to purchase an additional 9,200,000 common limited partnership units of CPLP. CPLP used the funds received from the Company to repay a portion of the outstanding indebtedness under its credit facilities, which was drawn to fund the acquisitions of the New England facilities, and for general corporate purposes including financing development projects and working capital requirements. This transaction reduced EPCOR's ownership interest in CPLP to approximately 48.9% effective for the third quarter from 54.1% at June 30, 2011.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on July 28, 2011 at 1:00 pm (ET) to discuss second quarter results. The conference call dial-in numbers are:

(403) 532-8075 (Calgary)
(604) 681-0262 (Vancouver)
(647) 837-0597 (Toronto)
(877) 353-9586 (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: (877) 353-9587 (toll-free) and entering conference reference number 549495# followed by participant code 21543#. The replay will be available until midnight on August 29, 2011.

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-IFRS Financial Measures

The Company uses (i) EBITDA, (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) normalized earnings attributable to common shareholders and (v) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to IFRS and do not have standardized meanings prescribed by IFRS, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, cash flow from operating activities or other measures of financial performance calculated in accordance with IFRS. Rather, these measures are provided to complement IFRS 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 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 July 27, 2011 for the six months ended June 30, 2011 which is available under the Company's profile on SEDAR at www.SEDAR.com.

Forward-looking Information

Certain information in this press release is forward-looking within the meaning of Canadian securities laws as it relates to anticipated financial performance, events or strategies. When used in this context, words such as will, anticipate, believe, plan, intend, target, and expect or similar words suggest future outcomes.

Forward-looking information in this press release includes, among other things, information relating to: (i) expectations regarding the outcome of the CPILP strategic review and the agreement with Atlantic Power pursuant to which Atlantic will acquire all of the outstanding limited partnership units of CPILP, Capital Power will acquire CPILP's Roxboro and Southport plants, and Capital Power will cease to manage CPILP; (ii) expectations regarding the timing of closing of the CPILP strategic review transactions, total consideration to be received and use of the consideration, and the gain on sale to be recognized in connection with the CPILP strategic review transaction in the fourth quarter; (iii) expectations regarding the commercial operation date of the Halkirk wind project, the total cost of the project, the impact on annual earnings per share for the first five years of operations, the after-tax internal rate of return over the life of the assets, and the total number of turbines the project will incorporate; (iv) expectations regarding the source of Halkirk's revenues and that 40% to 45% is expected to come from the sale of renewable energy credits; and (v) expectations that revenues from New England power plants will include payments for capacity, energy, and ancillary services at market-based rates.

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 include, but are not limited to: (i) the operation of the Company's facilities; (ii) power plant availability and dispatch, including Sundance which is subject to an acquired PPA; (iii) the Company's financial position and credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets, including power prices for 2011; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) weather; (vii) availability and cost of labour and management resources; (viii) performance of contractors and suppliers; (ix) availability and cost of financing; (x) foreign exchange rates; (xi) management's analysis of applicable tax legislation; (xii) currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; (xviii) ability to obtain necessary regulatory approvals for development projects; (xix) the Company's assessment of capital markets, common share ownership distribution, and ability to complete future share and debt offerings; (xx) locations of projects and the areas of which they will be developed, including the availability and use of certain optioned lands; (xxi) costs of construction and development; (xxii) current risk management strategies including hedges will be in place; (xxiii) ability to obtain court and regulatory approvals, and unitholders and shareholders favourable votes in relation to the CPILP strategic review transaction; and (xxiv) carrying amounts of assets held for sale.

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 risks and uncertainties include, but are not limited to, risks relating to: (i) operation of the Company's facilities; (ii) power plant availability and performance, including unplanned plant outages at facilities of other market participants; (iii) unanticipated maintenance and other expenditures; (iv) availability and price of energy commodities; (v) electricity load settlement; (vi) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (vii) weather and economic conditions; (viii) competitive pressures; (ix) construction; (x) availability and cost of financing; (xi) foreign exchange; (xii) availability and cost of labour, equipment and management resources; (xiii) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; (xiv) developments in the North American capital markets; (xv) compliance with financial covenants; (xvi) ability to successfully realize the benefits of acquisitions, investments and divestitures; (xvii) the tax attributes and implications of any acquisitions; (xviii) the completion of the CPILP strategic review transactions; and (xix) ability to secure new contracts and terms of such contracts. If any such risks actually occur, they could materially adversely affect the Company's business, financial condition or results of operations. In that case the trading price of the Company's common shares could decline, perhaps materially.

About Capital Power Corporation

Capital Power is a growth-oriented North American independent power producer, building on more than a century of innovation and reliable performance. Capital Power's vision is to be recognized as one of North America's most respected, reliable and competitive power generators. Headquartered in Edmonton, Alberta, Capital Power has interests in 34 facilities in Canada and the U.S. totaling nearly 4,900 megawatts of generation capacity. Capital Power and its subsidiaries develop, acquire and optimize power generation from a wide range of energy sources.

For more information, please contact:

Media Relations:
Mike Long
(780) 392-5207
mlong@capitalpower.com

Investor Relations:
Randy Mah
(780) 392-5305 or (866) 896-4636 (toll-free)
investor@capitalpower.com

CAPITAL POWER CORPORATION
Interim Report
June 30, 2011

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated July 27, 2011, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the six months ended June 30, 2011, the audited consolidated financial statements and MD&A of the Company for the year ended December 31, 2010 and the cautionary statement regarding forward-looking information which begins on page 36. In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation, together with its subsidiaries.

In this MD&A, financial information for the six months ended June 30, 2011 and six months ended June 30, 2010 is based on the unaudited condensed interim consolidated financial statements of the Company, which were prepared in accordance with International Financial Reporting Standards (IFRS), 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 July 27, 2011.

On January 1, 2011, IFRS, as issued by the International Accounting Standards Board, became the 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 2010, is presented in accordance with IFRS unless otherwise noted as being presented under previous Canadian GAAP (previous CGAAP). A discussion of the Company's transition to IFRS, including the impact of significant accounting policy choices and the selection of IFRS 1 elections and exemptions, is included in the Company's MD&As for the year ended December 31, 2010 and the three months ended March 31, 2011. A discussion of the reconciliations of equity as at June 30, 2010 and comprehensive income for the six months ended June 30, 2010 reported under previous CGAAP to reporting under IFRS can be found in the IFRS section which begins on page 31.

The Company's outstanding share capital on June 30, 2011 consisted of 40.445 million common shares, 5 million Cumulative Rate Reset Preference Shares, Series 1, 47.416 million special voting shares and one special limited voting share.

Corporate Strategy

The Company's corporate strategy remains unchanged from that disclosed in the 2010 annual MD&A. Based on its recent acquisitions, planned divestiture of its interest in CPILP (see Significant Events) and assessment of emerging opportunities, the Company updated the financial, geographic and technology criteria it uses to evaluate growth opportunities, as discussed below. The impact of the changes in criteria was to eliminate the pursuit of small hydro and biomass growth opportunities and to consider solar power opportunities. The changes also had the impact of increasing the scope of opportunities for contracted assets while reducing the scope of merchant opportunities, for the near term.

- Financial criteria – The target return for contracted assets was changed from 9% to 8% which the Company considers to be more competitive in current capital markets. The Company continues to target contracted plants to contribute approximately 50% of the Company's earnings before interest, taxes, depreciation and amortization (EBITDA). (EBITDA is a non-IFRS financial measure; see Non-IFRS Financial Measures in this MD&A).
- Technology focus – The Company will no longer pursue growth opportunities in biomass and hydro technologies. Following the planned divestiture of its interest in CPILP, the Company's portfolio will consist of coal, natural gas and wind technologies. Future growth will primarily be focused on merchant and contracted natural gas facilities, and contracted facilities supported by renewable technologies. Given the emerging opportunities in the Company's target markets, the Company plans to start exploring solar

development and acquisition opportunities. It also plans to divest its interests in hydro facilities, Brown Lake, Miller Creek and Taylor Coulee Chute in the near term.

- Geographic focus – The Company will continue to develop networked hubs in its three U.S. target markets and Alberta. In the Mid-Atlantic and U.S. South West markets, the Company expects to pursue only contracted opportunities in the near term. The Company will continue to consider merchant and contracted opportunities in the U.S. North East, where the Company has established the foundation of a networked hub through its recent acquisitions. The geographic focus will also be expanded to include monitoring for contracted wind and natural gas opportunities in the Pacific North West and Saskatchewan, two regions that are familiar to the Company. The expansion of the scope of opportunities for contracted assets will facilitate creating further growth of merchant plants in the Company's target markets.

The Company's New England plants and Halkirk Wind Project acquisitions in the second quarter of 2011 demonstrate the Company's commitment to its growth strategy aimed at reaching 10,000 MW of owned or operated generation capacity by 2020. The acquisitions also contribute to a balanced portfolio of contracted and merchant assets, employing proven power generation technology, meeting or exceeding the target rate of return, and growing in target markets. See Significant Events.

Financial Highlights

(unaudited, $millions, except earnings (loss) per share)	Three months ended		Six months ended	
	June 30, 2011	June 30 , 2010	June 30, 2011	June 30 , 2010
Revenues and other income	472	313	930	814
Gross income	217	117	384	334
EBITDA[1]	65	37	147	206
Net income (loss)	(22)	(34)	(8)	58
Net income (loss) attributable to shareholders of the Company	(25)	(8)	(22)	4
Earnings (loss) per share	$(0.67)	$ (0.37)	$(0.69)	$ 0.18
Fully diluted earnings (loss) per share[2]	$(0.67)	$ (0.37)	$(0.69)	$ 0.18
Normalized earnings per share[1]	$ 0.07	$ 0.05	$0.38	$0.56
Funds from operations[1]	87	61	190	164
Capital expenditures	120	121	209	183

(1) The consolidated financial information, except for EBITDA, normalized earnings per share and funds from operations, has been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

(2) Fully diluted earnings per share is calculated after giving effect to the exchange of limited partnership units of CPLP (exchangeable for common shares of Capital Power Corporation on a one-for-one basis) held by EPCOR Utilities Inc.

Funds from Operations

(unaudited, $millions)	Three months ended		Six months ended	
	June 30, 2011	June 30 , 2010	June 30, 2011	June 30 , 2010
Funds from operations excluding non-controlling interests in CPILP[1]	65	37	147	112
Funds from operations[1]	87	61	190	164

(1) Funds from operations and funds from operations excluding non-controlling interests in CPILP are non-IFRS measures. See Non-IFRS Financial Measures.

Funds from operations are cash provided by operating activities, including interest and current income tax expense rather than interest and income taxes paid, and excluding changes in working capital.

The increase in funds from operations excluding the non-controlling interest in CPILP for the second quarter of 2011 compared with the corresponding period in 2010 was primarily due to contributions from the New England facilities and Island Generation which were acquired in the second quarter of 2011 and the fourth quarter of 2010, respectively. In addition, availability penalties were lower for the scheduled outage at Genesee 1 in the second quarter of 2011 than at Genesee 2 in the second quarter of 2010.

Since the non-controlling interests in CPILP's funds from operations were approximately 70.8% (at June 30, 2011) the Company uses funds from operations excluding non-controlling interests in CPILP to provide a more meaningful measure of the Company's operating cash flows. See Non-IFRS Financial Measures.

Normalized Earnings and Normalized Earnings per Share

(unaudited, $millions except earnings (loss) per share and shares outstanding)	Three months ended				
	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010
Earnings (loss) per share	**$(0.67)**	**$0.06**	**$(0.13)**	**$0.73**	**$(0.37)**
Net income (loss) attributable to shareholders	(25)	3	(3)	16	(8)
Preferred share dividends	(2)	(1)	-	-	-
Earnings (loss) attributable to common shareholders	(27)	2	(3)	16	(8)
Adjustments	30	9	8	(2)	9
Normalized earnings attributable to common shareholders[1]	3	11	5	14	1
Weighted average number of common shares outstanding (millions)	40.42	32.32	23.47	21.77	21.75
Normalized earnings per share[1]	**$0.07**	**$0.33**	**$0.21**	**$0.64**	**$0.05**

(1) Normalized earnings attributable to common shareholders and normalized earnings per share are non-IFRS measures. See Non-IFRS Financial Measures.

Normalized earnings attributable to common shareholders for the second quarter of 2011 were lower in comparison to management's expectation and higher than the second quarter of 2010. The decrease from management's expectation was primarily attributable to the Alberta commercial plants and portfolio optimization, realized losses on the settlement of forward bond sale contracts, and an increase in the Company's pension obligation. The quarter over quarter increase in normalized earnings attributable to common shareholders was primarily due to contributions from the New England plants which were acquired in April 2011 and from Island Generation which was acquired in October 2010.

The Company uses normalized earnings attributable to common shareholders and normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings attributable to common shareholders are based on earnings used in the calculation of earnings per share as reported in the consolidated financial statements, adjusted for items that are not reflective of performance in the period such as fair value changes, impairment charges, unusual tax adjustments and gains or losses on disposal of assets and on unusual contracts. Normalized earnings per share for the second quarter of 2011 reflected normalized earnings attributable to common shareholders divided by 40.42 million weighted average common shares outstanding. See Non-IFRS Financial Measures.

Consolidated Net Income

(unaudited, $millions)	Three Months	Six Months
Net income (loss) for the periods ended June 30, 2010	**$ (34)**	**$ 58**
Unrealized changes in the fair value of CPLP's energy derivative instruments and natural gas inventory held for trading	36	(7)
Unrealized changes in the fair value of CPILP's derivative instruments	20	24
North East U.S. commercial plants and portfolio optimization EBITDA excluding unrealized changes in fair value	10	10
Higher Ontario and British Columbia contracted plants EBITDA	8	16
Higher Alberta contracted plants EBITDA	6	9
Gains on acquisitions and disposals	-	(28)
Lower Alberta commercial plants and portfolio optimization EBITDA excluding unrealized changes in fair value	(2)	(17)
Lower CPILP EBITDA excluding unrealized fair value changes	(6)	(10)
Higher finance expenses	(15)	(5)
Lower Corporate EBITDA excluding unrealized fair value changes	(51)	(57)
Other	5	(2)
Increase (decrease) before tax	11	(67)
Higher income tax recovery	1	1
Increase (decrease) in net income	12	(66)
Net loss for the periods ended June 30, 2011	**$ (22)**	**$ (8)**

Net income increased $12 million and decreased $66 million for the three and six months ended June 30, 2011, respectively compared with the corresponding periods in 2010 due to the net impact of the following:

- In the second quarter of 2011, the net unrealized change in the fair value of CPLP's derivative electricity and natural gas contracts and natural gas inventory held for trading that were not designated as hedges for accounting purposes was immaterial. In the second quarter of 2010, the fair value of these instruments decreased $36 million primarily due to the impact of significant increases in Alberta forward power prices on the Company's Alberta derivative electricity portfolio positions. For the six months ended June 30, the change in the fair value of these instruments resulted in a net unrealized loss of $34 million in 2011 compared with $27 million in 2010, primarily due to the impact of a larger increase in Alberta forward prices in the six-month period in 2011.
- The unrealized changes in the fair value of CPILP's derivative instruments primarily reflected decreases in the fair value of foreign exchange contracts in the three and six months ended June 30, 2010. The increase in income for the six months ended June 30, 2011 compared with the corresponding period in 2010 also reflected decreases in the fair value of natural gas supply contracts in the six months ended June 30, 2010.
- North East U.S. commercial plants and portfolio optimization EBITDA reflected contributions from the Rumford, Tiverton and Bridgeport facilities and trading in the North East U.S. power market since their acquisition in April 2011. See Significant Events.
- Ontario and British Columbia contracted plants EBITDA was higher primarily due to contributions from Island Generation following the Company's acquisition of the facility in the fourth quarter of 2010.
- Alberta contracted plants EBITDA was higher primarily due to lower availability incentive penalties for the scheduled maintenance outage at Genesee 1 in the second quarter of 2011 than for the scheduled maintenance outage at Genesee 2 in the second quarter of 2010. The decrease in penalties was due to lower rolling average power prices in the second quarter of 2011.
- On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of $64 million resulting in a pre-tax gain of $28 million and $2 million of associated income taxes. There was no comparable sale of assets in the first six months of 2011.
- Alberta commercial plants and portfolio optimization EBITDA was lower in the second quarter of 2011 primarily due to significant spikes in Alberta power prices in the second half of June as a result of unplanned and forced outages in the region, including the Company's acquired power purchase arrangement (PPA) at Sundance, which had an unfavourable impact on the Company's portfolio position. In the first quarter of 2011,

significant increases in Alberta power prices had an unfavourable impact on the Company's Alberta portfolio which was mitigated by higher generation from the dispatch of the Clover Bar Energy Centre and Joffre facility. In the first quarter of 2010, Alberta power prices were lower and had a favourable impact on the portfolio.

- CPILP EBITDA excluding unrealized fair value changes was lower primarily due to costs incurred in the second quarter of 2011 associated with the strategic review (see Significant Events) and the reversal of an allowance for doubtful accounts in the second quarter of 2010.
- Finance expense for the three and six months ended June 30, 2011 included a $10 million and $12 million loss respectively, related to the settlement of forward bond sale contracts whereas no such contracts settled in the corresponding periods in 2010. This increase in finance expense for the six months ended June 30, 2011, was partly offset by the impact of unrealized changes in the fair value of forward bond sale contracts. These contracts were entered into to economically hedge exposure to interest rate risk on anticipated debt issues. While these contracts settled at a loss, future interest payments will be incurred at a rate that is lower than the rate that was locked in by the hedge.
- Corporate general and administrative expenses were higher in the three and six months ended June 30, 2011 primarily due to an impairment loss of $43 million on the Company's management and operations contracts with CPILP as described under Significant Events. Corporate expenses also increased for an adjustment to the Company's supplemental pension obligation based on an actuarial valuation and for a loss realized on foreign exchange contracts, which were both recognized in the second quarter of 2011. See Corporate under Results by Plant Category.
- Income tax recoveries for the three and six months ended June 30, 2011 were higher than for the corresponding periods in 2010 primarily due to an adjustment to the future income tax liability relating to the Company's review of strategic alternatives for its investment in CPILP.

Outlook

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A as this information contains forward-looking statements based on risks and assumptions as of the date of this MD&A and as disclosed in that section. These forward-looking statements are for the purpose of providing information about management's current expectations and plans relating to the future and may not be appropriate for other purposes.

In January 2011, Unit 3 of the Clover Bar Energy Centre experienced an unplanned outage due to blade damage in its high pressure compressor. The unit was repaired under warranty and returned to service on June 17, 2011. The Company expects to file a claim for business interruption insurance in the third quarter of 2011, but the amount of the claim has not yet been determined. An outage at Unit 2 for an engine upgrade has been rescheduled from the summer of 2011 to November and December 2011. If plant operations perform as expected for the remainder of the year, the Company anticipates that plant availability for all plants, excluding CPILP plants, will be approximately 91% for the year compared with the 2011 target for this measure of 94%.

The commissioning of Keephills 3 commenced later than originally scheduled and the Company expects the commercial operation date of Keephills 3 will be during the third quarter of 2011. As discussed in the MD&A for the first quarter of 2011, the delay is expected to add approximately $20 million to $30 million or 2% to 3% of the total capital costs for the Company's share of the project.

At the beginning of the second quarter of 2011, the Company's forecast for normalized earnings for 2011 was $1.40 per share which was based on Alberta power prices for the balance of 2011 settling on average in the range of low-$60/MWh. However, Alberta power spot prices averaged $52/MWh for the second quarter including significant spikes in the second half of June due to unplanned and forced outages in the region including the Company's acquired PPA at Sundance. As a result, lower margins were realized on the Company's Alberta merchant trading portfolio than anticipated at the beginning of the quarter. The results for the second quarter were also impacted by the following costs which were not anticipated in the Company's previous guidance: a $5 million increase in its pension obligation and a $10 million loss on the settlement of forward bond sale contracts. The pension adjustment was a result of an actuarial valuation of the Company's supplementary pension obligation which incorporated updates to the estimates used at the time of the spinoff from EPCOR Utilities Inc.

(EPCOR). As such the Company does not anticipate material adjustments for future valuations. By economically hedging a portion of the debt issued in the second quarter, future interest payments on the debt will be at lower rates than those locked in by the forward bond sale contracts.

If Alberta power prices for the balance of 2011 settle on average in the range of their current forward prices of low $70/MWh, the Company expects normalized earnings per share for 2011 to be in line with the guidance provided in the March 31, 2011 MD&A, except for the impact of the loss on the settlement of bond forward contracts and the pension adjustment which were recognized in the second quarter. The Company anticipates the following updates to previous guidance included in the Company's 2010 annual MD&A for the remaining six months:

- At June 30, 2011, the Alberta portfolio positions were as follows for the remainder of 2011 and for 2012 and 2013:

Alberta Power Price Sensitivity	July to December 2011	Full year 2012	Full year 2013
% Sold forward	80%	35%	17%
Contracted price	Low-$60/MWh	Mid-$60/MWh	Mid-$60/MWh

- Depreciation expense for 2011 is expected to include approximately $20 million ($10 million for the second half of 2011) for the depreciation on current and prior years' shutdown maintenance costs that are capitalized under IFRS. Under previous CGAAP, the costs were expensed as incurred.
- The estimated useful lives of the Company's Genesee and Keephills 3 plants were extended from 35 years to 45 years. The impact on depreciation expense in 2011 is expected to be a decrease of approximately $14 million ($7 million for the second half of 2011) from previous estimates.
- The earnings contribution from the three New England plants for May and June, 2011 was generally in line with management's expectations. Other than the expected negative impact of $2 million for a Connecticut energy tax which was introduced in June 2011, the 2011 earnings guidance remains substantially the same as that reported in the March 31, 2011 MD&A.
- Financing costs in 2011 will include interest on the $300 million medium-term notes issued in April 2011 and the US$295 million senior notes issued in June 2011 as discussed under Significant Events.
- In March 2011, the Company issued 9,300,000 common shares to the public to partially finance the New England plant acquisitions. In accordance with the terms of the CPLP partnership agreement, net income from CPLP for the year will be allocated to the partners (subsidiaries of EPCOR and Capital Power) on the same basis as distributions for the year are allocated. Since the public share offering closed before the date of record for the first quarter distribution by CPLP, the transaction effectively occurred January 1, 2011 for purposes of allocating net income to the partners. As a result, Capital Power's and EPCOR's share of net income were approximately 46% and 54%, respectively for the first and second quarters. In July 2011, the Company issued 9,200,000 common shares which reduced EPCOR's ownership interest in Capital Power to approximately 48.9% effective for the third and fourth quarters. See Subsequent Event.

The 2011 targets and normalized earnings per share forecasts are based on numerous assumptions including power and natural gas price forecasts, as described in the Forward-looking Information section. However, they do not include the effects of the planned divestiture of the Company's interest in CPILP as discussed under Significant Events, including the impairment loss recorded in the second quarter and the anticipated gain on sale and foreign translation loss to be recorded in the fourth quarter as they are not considered to be normalized earnings. They also do not include the impacts from 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.

In June 2011, CPILP executed final PPAs for Southport and Roxboro replacing an interim PPA that was effective April 1, 2011 under terms that were substantially consistent with the interim PPA. EBITDA for the plants is expected to average US$15 million during the 10-year term of the final PPAs, with higher earnings expected in the earlier years. The Company expects the capitalized maintenance costs for these plants to be approximately US$3 million per year for the term of the PPAs.

The New England plant acquisitions and Halkirk wind project discussed under Significant Events, contribute approximately $1.0 billion towards the Company's target of $1.5 billion of capital to be committed in 2011.

The Company's estimated capital expenditures in 2011 in the following table exclude the cost of the New England plant acquisitions and potential new development projects.

(unaudited, $millions) **Capital Expenditures**			Year ended Dec 31, 2011 Estimated[(1)]
CPLP	Sustaining	Plant maintenance	$ 40
		Genesee mine maintenance[(2)]	24
		New England plant maintenance	7
		Information technology	13
		Other	14
			98
CPLP	Growth	Halkirk	190
		Keephills 3	88
		Quality Wind	148
		Port Dover & Nanticoke	54
			480
CPLP Total			578
CPILP	Sustaining	Plant maintenance	25
	Growth		5
CPILP Total			30
			608

(1) Capital expenditures for the year ended December 31, 2011 are based on management's estimates.

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

The capital expenditure estimates in the table above reflect the following updates to the guidance included in the 2010 annual MD&A:

- Estimated plant maintenance capital expenditures are approximately $16 million higher due to the impact of IFRS whereby costs for major maintenance are capitalized rather than expensed.
- Estimated Genesee mine maintenance capital expenditures are approximately $8 million higher due to increased opportunities to purchase lands for the ongoing expansion of the mine.
- Approximately $7 million of plant maintenance capital expenditures are anticipated for the three New England plants.
- The total estimated expenditures in 2011 for the Halkirk wind project costs (discussed under Significant Events) are $190 million, including $33 million spent in the second quarter for the acquisition of intangible assets and approximately $157 million for construction of the project throughout 2011.
- Estimated capital expenditures for Keephills 3 are approximately $20 million to $30 million higher due to revised timing of the plant commissioning.
- The construction schedule for the Port Dover & Nanticoke wind project was revised to accommodate completion of the land title transfers resulting in $44 million of planned expenditures being deferred to 2012. The change is not anticipated to impact the completion date of the fourth quarter of 2012 or the total project cost of $340 million.

Significant Events

CPILP strategic review and acquisition of CPILP's Roxboro and Southport facilities

On June 20, 2011, the Company announced that CPILP had entered into an agreement with Atlantic Power Corporation (Atlantic) pursuant to which Atlantic will acquire, directly and indirectly, all of the outstanding limited partnership units of CPILP, including Capital Power's approximate 29.2% ownership interest in CPILP. In connection with the agreement, Capital Power will acquire CPILP's Roxboro and Southport plants in North Carolina for $121 million in cash. Atlantic will acquire CPILP and its remaining eighteen facilities outside North Carolina. The announcement follows the completion of the strategic review process announced by CPILP and Capital Power Corporation in October 2010.

Completion of the transactions is subject to customary closing conditions, including Canadian court approvals, a favourable vote by CPILP unitholders, a favourable vote by the Atlantic shareholders, and the receipt of all necessary regulatory approvals. If the closing conditions are met, the transactions are expected to close in the fourth quarter of 2011, at which time Capital Power will cease to manage CPILP.

Upon closing, Capital Power will receive approximately $320 million in combined consideration for its approximate 29.2% ownership interest in CPILP. The consideration will include cash or stock in Atlantic at Capital Power's election subject to proration, and the cash will be used to fund the acquisition of the North Carolina plants. In addition, the Company's management and operations contracts with CPILP will be terminated or assigned in consideration of payment of an aggregate of $10 million to Capital Power.

At June 30, 2011, the Company tested the CPILP net assets and management and operations contracts for impairment at the cash generating unit level, by comparing their recoverable amounts with their carrying amounts. The negotiated consideration to be received for these assets less an estimate for disposal costs was used as the estimated recoverable amount. As a result, the management and operations contracts were determined to be impaired and an impairment loss of $43 million was recorded in the second quarter.

The carrying amounts of the disposal group of assets and liabilities, after recognizing the impairment loss, were reclassified as assets and liabilities held for sale on the Company's statement of financial position at June 30, 2011. Upon closing of the transactions in the fourth quarter of 2011, the Company anticipates that a pre-tax gain of approximately $125 million ($54 million attributable to common shareholders) will be recognized for the difference between the net proceeds and the carrying amount of the Company's interest in CPILP net assets classified as assets held for sale, calculated as follows:

(unaudited, $millions)	Net Assets Held for Sale		
	Management and operating contracts	Interest in CPILP net assets	Total
Carrying amount before asset impairment loss	$ 53	$ 185	$ 238
Asset impairment loss recognized in the second quarter of 2011	(43)	-	(43)
Carrying amount at June 30, 2011 and reclassified as assets held for sale	10	185	195
Estimated net proceeds on disposal upon closing in the fourth quarter of 2011	10	310	320
Estimated pre-tax gain on disposal in the fourth quarter of 2011	-	125	125
Estimated income tax expense	-	(7)	(7)
Estimated gain attributable to non-controlling interests	-	(64)	(64)
Estimated net income attributable to common shareholders in the fourth quarter of 2011 from the gain on disposal	-	54	54

The Company also anticipates that upon closing of the transactions the cumulative translation account relating to CPILP's U.S. operations, other than the North Carolina plants, will be reclassified from accumulated other comprehensive loss to the income statement. The Company's accumulated translation account represents the foreign currency translation differences for foreign operations, which have been recognized since the Company's transition to IFRS on January 1, 2010, and will be reclassified to net income upon disposal of the foreign operations. At June 30, 2011, accumulated other comprehensive loss included $4 million of foreign currency translation losses attributable to common shareholders for the CPILP foreign operations to be disposed of in the fourth quarter. This amount plus the corresponding translation gains or losses for the period from July 1, 2011 to the date of the sale are expected to be reclassified to net income in the fourth quarter.

The calculations of the gain on disposal of the assets held for sale and the foreign currency translation loss that will be recognized in income in the fourth quarter of 2011 are based on estimates and carrying amounts as of June 30, 2011 that could change materially by the time the transaction closes.

Acquisition of Halkirk wind project

On May 25, 2011, CPLP acquired 100% of Halkirk I Wind Project LP and Halkirk I Wind Project Ltd from Greengate Power Corporation for $33 million. The assets of the acquired entities were comprised of intangible assets including various permits and land lease rights required to construct the Halkirk Wind Project (Halkirk), and a 20-year PPA for the sale of renewable energy credits to a third party. Halkirk is a 150-MW wind farm located in east central Alberta, which Capital Power will build, own and operate. All approvals and permits from the Alberta Utilities Commission and Alberta Environment are in place for the facility.

Commercial operation is expected in the last half of 2012 and the total cost of the project, including the $33 million cost of the intangible assets is expected to be approximately $357 million. The project is expected to be on average, neutral to the Company's annual earnings per share over the first five years of operations. Halkirk will earn revenues from the sale of energy into the Alberta spot market, and from the sale of renewable energy credits under the 20-year fixed-price PPA. Approximately 40% to 45% of Halkirk's revenue is expected to come from the sale of renewable energy credits and the project has a favourable after-tax internal rate of return over the projected life of its assets.

Halkirk will incorporate 83 turbines to be supplied by Vestas Canadian Wind Technology Inc., the same technology to be used at Capital Power's Quality Wind project in British Columbia and Port Dover & Nanticoke project in Ontario.

Acquisition of three New England power plants

On April 28, 2011, CPLP acquired 100% of the equity interests in Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport), for $344 million (US$362 million) including a working capital adjustment of $6 million (US$7 million). Bridgeport is a natural gas-fired combined cycle power generation plant located in Bridgeport, Connecticut, with a nominal capacity of 520 MW.

On April 29, 2011, CPLP acquired 100% of the equity interests in Tiverton Power Inc. and Rumford Power Inc. (Tiverton and Rumford) which own generating facilities located in Tiverton, Rhode Island and Rumford, Maine respectively. Both plants are natural gas-fired combined cycle power generation facilities serving the New England region in the U.S. Northeast, and have a maximum combined capacity of 549 MW. The purchase price was $299 million (US$315 million).

All three plants are merchant facilities and sell their output into the New England Power Pool (NEPOOL). Their revenues are expected to include payments for capacity, energy, and ancillary services at market-based rates.

$300 million debt offering

On April 18, 2011, CPLP completed a public offering of $300 million unsecured medium-term notes. The notes have a coupon rate of 4.6%, are payable semiannually commencing on June 1, 2011, and mature on December 1, 2015. The net proceeds of the offering were used for general corporate purposes including repayment of amounts owing under credit facilities, short-term investment, financing of ongoing capital projects and working capital requirements.

US$295 million private placement of senior notes

On June 15, 2011, Capital Power U.S. Financing LP, an indirect subsidiary of CPLP, closed a US$295 million private placement of senior notes. The net proceeds from the transaction were primarily used to fund the acquisition of the three New England facilities and for general corporate purposes.

The senior notes consist of two notes with 10-year and 15-year terms. The 10-year senior note has a principal amount of US$230 million that matures in May 2021 with a coupon rate of 5.21%. The 15-year senior note has a US$65 million principal amount and matures in May 2026 with a coupon rate of 5.61%.

Subsequent Event

$231 million common share offering

In July 2011, the Company closed an offering to sell 9,200,000 common shares at a price of $25.10 per share to a syndicate of underwriters for gross proceeds of approximately $231 million, less underwriters' fees of approximately $9 million. The net proceeds from the common share offering were used to purchase an additional

9,200,000 common limited partnership units of CPLP. CPLP used the funds received from the Company to repay a portion of the outstanding indebtedness under its credit facilities, which was drawn to fund the acquisitions of the New England facilities, and for general corporate purposes including financing development projects and working capital requirements. This transaction reduced EPCOR's ownership interest in CPLP to approximately 48.9% effective for the third quarter from 54.1% at June 30, 2011.

Results by Plant Category

The Company reports results of operations in the following categories: (i) Alberta commercial plants 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) CPILP plants, (vi) Other portfolio activities, and (vii) Corporate.

Generation volume

(unaudited, GWh)	Three months ended		Six months ended	
Electricity generation[(1)]	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
Alberta commercial plants				
Genesee 3	477	432	959	915
Keephills 3[(2)]	50	-	50	-
Joffre	57	93	155	134
Clover Bar Energy Centre 1, 2 and 3	40	102	202	145
Taylor Coulee Chute	2	3	2	3
Clover Bar Landfill Gas	9	10	17	20
Weather Dancer[(3)]	-	-	-	-
	635	640	1,385	1,217
Alberta contracted plants				
Genesee 1	661	780	1,429	1,593
Genesee 2	789	571	1,620	1,396
	1,450	1,351	3,049	2,989
Ontario and British Columbia contracted plants				
Kingsbridge 1	24	22	55	48
Miller Creek	26	35	31	42
Brown Lake	15	11	29	24
Island Generation	55	-	107	-
	120	68	222	114
North East U.S. commercial plants[(4)]				
Rumford	68	-	68	-
Tiverton	289	-	289	-
Bridgeport	645	-	645	-
	1,002	-	1,002	-
Total excluding CPILP plants	**3,207**	**2,059**	**5,658**	**4,320**
CPILP plants	1,155	1,128	2,294	2,397
Total plants	**4,362**	**3,187**	**7,952**	**6,717**
Sundance PPA	**701**	**728**	**1,459**	**1,479**

(1) Electricity generation reflects the Company's share of plant output.

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

(3) The Weather Dancer facility was divested in the second quarter of 2011.

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

Plant availability

(unaudited)	Three months ended		Six months ended	
Generation plant availability[1]	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
Alberta commercial plants				
Genesee 3	100%	96%	100%	98%
Joffre	78%	84%	88%	92%
Clover Bar Energy Centre 1, 2 and 3	65%	52%	65%	62%
Taylor Coulee Chute	94%	90%	97%	94%
Clover Bar Landfill Gas	86%	96%	90%	96%
Weather Dancer[2]	-%	0%	0%	41%
	82%	76%	84%	83%
Alberta contracted plants				
Genesee 1	81%	100%	86%	99%
Genesee 2	99%	75%	99%	86%
	90%	87%	93%	93%
Ontario and British Columbia contracted plants				
Kingsbridge 1	99%	100%	99%	99%
Miller Creek	99%	96%	89%	67%
Brown Lake	99%	99%	100%	98%
Island Generation	100%	-	100%	-
	100%	98%	98%	86%
North East U.S. commercial plants[3]				
Rumford	99%	-	99%	-
Tiverton	97%	-	97%	-
Bridgeport	100%	-	100%	-
	99%	-	99%	-
Average excluding CPILP plants[4]	**91%**	**83%**	**92%**	**88%**
CPILP plants	88%	90%	90%	92%
Average all plants[4]	**90%**	**86%**	**91%**	**90%**
Sundance PPA	**91%**	**93%**	**95%**	**95%**

(1) 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.

(2) The Weather Dancer facility was divested in the second quarter of 2011.

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

(4) Average generation plant availability is an average of individual plant availability weighted by the capacity owned or operated by the Company.

The increase in total plant electricity generation, excluding generation from the Sundance PPA, for the six months ended June 30, 2011 compared with the corresponding period in 2010 primarily related to Joffre, Clover Bar Energy Center, Genesee Units 2 and 3, and commissioning generation at Keephills 3; as well as generation from Island Generation and the New England facilities which were acquired in the fourth quarter of 2010 and second quarter of 2011 respectively.

Genesee Unit 1 had a 21-day outage from March 28 to April 18, 2011 and Genesee unit 2 had a 21-day outage during the second quarter of 2010, both of which were for scheduled maintenance.

Joffre and Clover Bar Energy Centre are mid-merit and peaking plants, respectively, which operate when it is economical to do so. Alberta power prices were lower in the second quarter of 2011 compared with the corresponding period of 2010 and resulted in fewer opportunities to dispatch these plants. Conversely, higher Alberta power prices in the first quarter of 2011 resulted in more generation from these plants than in the first quarter of 2010. Availability of Clover Bar Energy Centre was negatively impacted by outages in both 2010 and

2011. Unit 3 was offline from January 15, 2011 to June 17, 2011 due to blade damage in its high pressure compressor and the repair work was covered under warranty by the manufacturer. In 2010, Unit 2 was offline from March 8 to September 22 due to a mechanical failure in the main turbine section and the repair work was covered under warranty. Unit 3 was also offline in 2010 for 18 days in the first quarter and 15 days in the second quarter. The Joffre plant's lower availability for the quarter ended June 30, 2011 was due to scheduled and unscheduled outages for two of the three turbines.

Financial results

(unaudited, $millions)	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
Revenues and other income				
Alberta commercial plants and portfolio optimization	$ 215	$ 197	$ 481	$ 432
Alberta contracted plants	64	57	141	130
Ontario and British Columbia contracted plants	13	3	26	6
North East U.S. Commercial plants and portfolio optimization[(1)]	51	-	51	-
CPILP plants	129	116	257	255
Other portfolio activities	18	22	52	65
Corporate	6	10	12	16
Inter-plant category transaction eliminations	(17)	(18)	(37)	(33)
	479	387	983	871
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	(8)	(55)	(57)	(43)
Unrealized changes in fair value of CPILP's foreign exchange contracts	1	(19)	4	(14)
	(7)	(74)	(53)	(57)
	$ 472	**$ 313**	**$ 930**	**$ 814**
Gross income				
Alberta commercial plants and portfolio optimization	$ 57	$ 59	$ 107	$ 124
Alberta contracted plants	52	42	114	100
Ontario and British Columbia contracted plants	13	3	26	6
North East U.S. Commercial plants and portfolio optimization[(1)]	15	-	15	-
CPILP plants	75	68	147	145
Other portfolio activities	9	6	18	21
Corporate	6	10	12	16
Inter-plant category transaction eliminations	(12)	(17)	(25)	(31)
	215	171	414	381
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	-	(36)	(34)	(27)
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	2	(18)	4	(20)
	2	(54)	(30)	(47)
	$ 217	**$ 117**	**$ 384**	**$ 334**
EBITDA[(2)]				
Alberta commercial plants and portfolio optimization	$ 44	$ 46	$ 82	$ 99
Alberta contracted plants	35	29	82	73
Ontario and British Columbia contracted plants	10	2	20	4
North East U.S. Commercial plants and portfolio optimization[(1)]	10	-	10	-
CPILP plants	37	43	82	92
Other portfolio activities	2	(5)	2	1
Corporate	(75)	(24)	(101)	(44)
Inter-plant category transaction eliminations	-	-	-	-
	63	91	177	225
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	-	(36)	(34)	(27)
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	2	(18)	4	(20)
	2	(54)	(30)	(47)
Gain on sale of power syndicate agreement	-	-	-	28
	$ 65	**$ 37**	**$ 147**	**$ 206**

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

(2) The results by plant category, except for EBITDA, have been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

Spot price averages	Three months ended June 30, 2011	June 30, 2010	Six months ended June 30, 2011	June 30, 2010
Alberta power ($/MWh)	52	81	67	61
Eastern region power ($/MWh)	28	37	30	35
Western region power (Mid-C) ($/MWh)	20	25	19	34
Alberta natural gas (AECO) ($/Gj)(1)	4	4	4	4

Capital Power's Alberta portfolio's realized power price ($/MWh)(2)	56	66	60	67

(1) 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.

(2) The price realized on the Company's commercial contracted sales and portfolio optimization activities.

Alberta commercial plants and portfolio optimization

The average Alberta power spot price decreased from $82/MWh for the first quarter to $52/MWh for the second quarter of 2011 due to more moderate temperatures and decreased demand. Prices were particularly low in May followed by a significant spike in the latter half of June when a number of unplanned outages occurred in the region including the Company's acquired PPA units at Sundance. This unexpected increase in price and the low spot prices in April to early June had an unfavourable impact on the portfolio and resulted in a lower realized price for the Company's Alberta portfolio for the second quarter of 2011 compared with the second quarter of 2010.

In the second quarter of 2010, the Alberta spot price averaged $81/MWh primarily due to Genesee plant curtailments and other de-rates on the Alberta electric system. Despite the lower Alberta spot price in the second quarter of 2011, the gross income and EBITDA for the Alberta commercial plants and portfolio optimization were only slightly lower than the results for the corresponding period in 2010. The high prices and high volatility in those prices in the second quarter of 2010 had an unfavourable impact on the Company's merchant trading portfolio.

The decrease in gross income and EBITDA for the six months ended June 30, 2011 compared with the corresponding period in 2010, was primarily due to the unfavourable impact of the sudden increase in Alberta power prices on the commodity optimization portfolio in the first quarter of 2011. The high prices were due to colder than normal weather and changes in power supply due to the shutdown of two large coal plants. In the first quarter of 2010, lower Alberta power prices had a favourable impact on the portfolio resulting in higher margins.

Revenues for the six months ended June 30, 2011 were higher than for the corresponding period in 2010 primarily due to the impact of higher Alberta power prices on the generation volume from the plants and higher pricing for the supply of electricity to EPCOR's rate-regulated tariff (RRT) customers, partly offset by losses on merchant financial sell contracts in the first quarter of 2011 compared with gains on these contracts in the first quarter of 2010. The increase in revenue from the Company's RRT business did not have a significant impact on EBITDA as the Company's purchases and revenues for this business are impacted by changes in the Alberta power price and provide a low margin per MWh. The Company's RRT power supply contract with EPCOR expired in June 2011 and will not be renewed.

Alberta contracted plants

Revenues, gross income and EBITDA for the Alberta contracted plants increased in the three and six months ended June 30, 2011, compared with the corresponding periods in 2010 primarily due to higher net availability incentive revenues. In the second quarter of 2011, the 21-day scheduled maintenance outage at Genesee 1 resulted in $5 million of availability penalties compared with $12 million related to the Genesee 2 21-day outage in the corresponding period in 2010. Prices for availability incentive revenues and penalties are a function of a 30-day rolling average of Alberta power prices, and were significantly lower during the outage in the second quarter of 2011 than during the outage in the corresponding period in 2010. In the first quarter of 2011, higher rolling average power prices resulted in higher availability incentive revenues compared with the corresponding period in 2010.

Ontario and British Columbia contracted plants

The higher revenues, gross income and EBITDA for the Ontario and British Columbia contracted plants primarily reflected contributions from the Island Generation facility following its acquisition in the fourth quarter of 2010.

North East U.S. commercial plants & portfolio

The North East U.S. commercial plants and portfolio optimization reflected contributions from the Tiverton, Rumford and Bridgeport facilities following their acquisition in the second quarter of 2011. See Significant Events.

CPILP plants

CPILP plants' revenues and gross income excluding unrealized fair value changes increased in the three months ended June 30, 2011 compared with the corresponding period in 2010 primarily due to higher generation at Curtis Palmer as a result of higher water flows and higher generation at the North Carolina plants. Revenues were higher in the six months ended June 30, 2011 primarily due to higher generation at the Curtis Palmer and North Carolina plants, partly offset by lower fuel recovery revenues at the California plants in the first quarter of 2011, driven by reduced generation and lower natural gas supply prices. The lower fuel recovery revenues were offset by lower fuel expenses for these plants and therefore had an immaterial impact on gross income in the first quarter of 2011.

The EBITDA for the CPILP plants decreased primarily due to administrative costs incurred in the second quarter of 2011 for the strategic review (see Significant Events), and a reversal of an allowance for doubtful accounts in the second quarter of 2010.

Other portfolio activities

Other portfolio activities include trading of environmental credits and natural gas in North American markets, and electricity trading in the U.S. Pacific Northwest markets. The decrease in revenue in the three and six months ended June 30, 2011 was primarily due to fewer trading opportunities in the natural gas and U.S. Pacific Northwest electricity markets, partly offset by higher emission credit sales. The increase in gross income and EBITDA for the second quarter of 2011 primarily reflected net losses from natural gas trading activities in the second quarter of 2010. For the six months ended June 30, 2011, the net losses from natural gas trading activities in the first quarter offset the increase in gross income and EBITDA for these activities in the second quarter. As a result, the change in gross income and EBITDA for the six months ended June 30, 2011 compared with the six month period in 2010 was insignificant.

Although emission credit sales were higher in the three and six months ended June 30, 2011, the margins earned on these sales were not significant.

Corporate

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

Corporate expenses for the three months ended June 30, 2011 included an impairment loss of $43 million relating to Capital Power's management and operations agreements with CPILP, a $5 million unfavourable pension adjustment and a $4 million loss on the settlement of foreign exchange contracts. The impairment loss was recorded as a result of the Company's agreement with Atlantic Power to terminate or assign the contracts in exchange for $10 million. See Significant Events. The pension adjustment 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. With the reduction in uncertainty associated with the estimates, the Company does not anticipate material adjustments for future valuations. The foreign exchange contracts entered into in anticipation of U.S. cash payments related to the acquisition of the New England facilities and no foreign exchange contracts were settled in the corresponding period of 2010.

The increase in corporate expenses for the six months ended June 30, 2011 included the items noted above for the quarter as well as professional fees for the New England plant acquisitions.

Unrealized changes in fair value of derivative instruments and natural gas inventory held for trading

In the second quarter of 2011, the net unrealized change in the fair value of CPLP's derivative electricity and natural gas contracts and natural gas inventory held for trading that were not designated as hedges for accounting purposes was immaterial. In the second quarter of 2010, the fair value of these instruments decreased $36 million primarily due to the impact of significant increases in Alberta forward power prices on the Company's Alberta derivative electricity portfolio positions.

The unrealized decreases in the fair value of CPLP's derivative electricity and natural gas contracts and natural gas storage held for trading of $34 million in the six months ended June 30, 2011 and $27 million in the six months ended June 30, 2010 were primarily due to the impact of increases in Alberta forward power prices on the Company's Alberta derivative electricity portfolio positions.

CPILP's revenues included net gains of $1 million and $4 million for changes in the fair value of foreign exchange contracts in the three and six months ended June 30, 2011, respectively compared with net losses of $19 million and $14 million, respectively in the corresponding periods in 2010. These changes in fair value were primarily due to a decrease in the forward prices for U.S. dollars relative to Canadian dollars of $0.006 and $0.030 in the three and six months ended June 30, 2011 respectively, compared with increases of $0.057 and $0.033 for the corresponding periods in 2010.

The unrealized changes in the fair value of CPILP's natural gas supply contracts that were not designated as hedges for accounting purposes were included in fuel expense. These changes were immaterial in the first six months of 2011 compared with a decrease of $6 million in the corresponding period in 2010 due to a decrease of $0.14/Gj and $0.77/Gj in Alberta forward prices for natural gas respectively.

Gain on sale of power syndicate agreement

On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of $64 million resulting in a pre-tax gain of $28 million. There was no comparable gain on sale of assets during the first quarter of 2011. The sale of the Battle River PSA did not have an impact on earnings attributable to the common shareholders of the Company as approximately $11 million was added to the carrying amount of the asset when it was acquired from EPCOR representing the Company's 27.8% interest in the asset's fair value increment. Accordingly this increment was attributable to the equity holders of the Company and not the non-controlling interests.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $millions)	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Finance expense excluding unrealized changes in fair value of forward bond sale contracts	31	16	50	35
Unrealized loss (gain) for changes in fair value of forward bond sale contracts	4	4	(6)	4
Depreciation and amortization	64	62	122	119
Income tax recovery	(12)	(11)	(11)	(10)
Net income (loss) attributable to non-controlling interests	3	(26)	14	54

Finance expense

The increase in finance expense excluding unrealized changes in fair value for the three and six months ended June 30, 2011 was primarily due to a net loss realized on the settlement of forward bond sale contracts of $10 million and $12 million respectively, compared with no contract settlements in the corresponding periods in 2010. Interest expense was also higher in the periods ending June 30, 2011 as a result of the $300 million debt offerings in November 2010 and April 2011 and the US$295 million private placement of senior notes in June 2011.

The forward bond sale contracts were entered into to economically hedge the Company's exposure to interest rate risk on anticipated debt issues. While these contracts settled at a loss in the second quarter of 2011, future interest payments related to the hedged debt will be incurred at a rate lower than the locked in rate.

Depreciation and amortization

Depreciation and amortization expense was higher for the three and six months ended June 30, 2011 compared with the corresponding periods in 2010, primarily due to the depreciation of Island Generation and the New England facilities following their acquisitions in the fourth quarter of 2010 and second quarter of 2011, respectively. This was partly offset by lower depreciation on the Genesee assets as a result of the change in the estimated useful life of the coal plants from 35 years to 45 years effective January 1, 2011.

Income tax recovery

Income tax recovery was higher for the three and six months ended June 30, 2011 compared with the corresponding periods in 2010 primarily due to an adjustment to the future income tax liability in the second quarter of 2011 relating to the Company's review of strategic alternatives for its investment in CPILP. See Significant Events. This was partly offset by the impact of higher taxable income in the three and six months ended June 30, 2011 and the increased ownership of CPLP following the issue of common limited partnership units in December 2010 and March 2011.

Non-controlling interests

The non-controlling interests in CPILP reflect approximately 70.8% (69.6% at June 30, 2010) of CPILP net income, and the non-controlling interests in CPLP reflected approximately 54.1% (72.2% at June 30, 2010) of the net income from CPLP (net of preferred share dividends). Non-controlling interests on the statement of income also included the Genesee coal mine partner's share of the consolidated coal costs.

Non-controlling interests for the three and six months ended June 30, 2011 included approximately $4 million of the $43 million impairment loss on the Company's management and operations contracts with CPILP as the majority of the contracts in terms of their carrying amounts, are owned by Capital Power Corporation rather than CPLP. Non-controlling interests for the six months ended June 30, 2010 included 100% of the gain on sale of the Battle River PPA. The sale had no impact on the Company's net income as its 27.8% share of the fair value of the Battle River PPA was recognized in the purchase price allocation for its acquisition of power generation assets and operations (the Reorganization) from EPCOR Utilities Inc. on July 9, 2009.

Income from CPLP included approximately 29.2% (30.4% at June 30, 2010) of the CPILP net income. Therefore the non-controlling interests in CPLP included approximately 15.8% (54.1% of 29.2%) of CPILP net income in the second quarter of 2011 and 21.9% (72.2% of 30.4%) in the second quarter of 2010.

Non-IFRS Financial Measures

The Company uses (i) EBITDA, (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) normalized earnings attributable to common shareholders and (v) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to IFRS and do not have standardized meanings prescribed by IFRS, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, cash flow from operating activities or other measures of financial performance calculated in accordance with IFRS. Rather, these measures are provided to complement IFRS 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 groups of plants from period to period. A reconciliation of EBITDA to net income is as follows:

(unaudited, $millions)	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
Revenues	$ 455	$ 301	$ 895	$ 785
Other income	17	12	35	29
Energy purchases and fuel	(255)	(196)	(546)	(480)
Gross income	**217**	**117**	**384**	**334**
Other raw materials and operating charges	37	22	66	41
Staff costs and employee benefits expense	42	47	81	88
Other administrative expenses	20	9	30	19
Property taxes	6	4	11	9
Impairments	43	-	43	-
Foreign exchange losses (gains)	4	(2)	6	(1)
Gain on sale of power syndicate agreement	-	-	-	(28)
EBITDA	65	37	147	206
Depreciation and amortization	64	62	122	119
Finance expense	35	20	44	39
Income tax recovery	(12)	(11)	(11)	(10)
Net income (loss)	**$ (22)**	**$ (34)**	**$ (8)**	**$ 58**
Attributable to:				
Non-controlling interests	3	(26)	14	54
Shareholders of the Company	(25)	(8)	(22)	4

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

Capital Power uses funds from operations to measure the Company's ability to generate funds from current operations. Funds from operations are cash provided by operating activities, including financing and current income tax expenses, and excluding changes in working capital. Changes in working capital are impacted by the timing of cash receipts and payments and are not comparable from period to period. As a result of the transition to IFRS, interest paid, excluding capitalized interest, and income taxes paid and recovered have been moved into the body of the consolidated statement of cash flows as part of operating activities. These amounts were previously disclosed as supplementary information and captured within the consolidated statement of cash flows within changes in non-cash operating working capital. In its funds from operations and funds from operations excluding non-controlling interests in CPILP, the Company includes interest and current income tax expense recorded during the period, rather than interest and taxes paid which are impacted by the timing of cash receipts and payments and are not comparable from period to period. Therefore, the Company uses funds from operations as its primary operating cash flow measure. The Company measures its interest in cash flows by excluding the non-controlling interest in CPILP's cash flows. A reconciliation of (i) funds from operations and (ii) funds from operations excluding non-controlling interests in CPILP, to cash flows from operating activities is as follows:

(unaudited, $millions)	Three months ended		Six months ended	
	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010
Funds from operations excluding non-controlling interests in CPILP	**$ 65**	**$ 37**	**$ 147**	**$ 112**
Funds from operations due to non-controlling interests in CPILP	22	24	43	52
Funds from operations	**87**	**61**	**190**	**164**
Adjustments:				
Unrealized changes in the fair value of forward bond contracts	(4)	(4)	6	(4)
Settlement of forward bond contracts	(10)	-	(12)	-
Miscellaneous financing charges	(2)	(3)	(4)	(7)
Finance expense	35	20	44	39
Interest paid	(19)	(16)	(31)	(28)
Income taxes (paid) recovered	(3)	(1)	(12)	7
Current income tax expense excluding future income taxes	(3)	-	1	14
Change in non-cash operating working capital	(14)	(25)	(14)	(26)
Cash flows from operating activities	**67**	**32**	**168**	**159**

Normalized earnings 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 IFRS adjusted for items that are not reflective of performance in the period such as fair value changes, impairments charges, unusual tax adjustments and gains or losses on disposal of assets or on unusual contracts such as the contract for maintenance of EPCOR's Rossdale plant. 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 earnings (loss) per share)	Three months ended				
	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010
Earnings (loss) per share	$(0.67)	$0.06	$(0.13)	$0.73	$(0.37)
Net income (loss) attributable to shareholders	(25)	3	(3)	16	(8)
Preferred share dividends	(2)	(1)	-	-	-
Earnings (loss) attributable to common shareholders	(27)	2	(3)	16	(8)
Adjustments					
Unrealized changes in fair value of CPLP's derivative instruments and natural gas held for trading	2	9	3	(2)	8
Unrealized changes in fair value of CPILP's derivative instruments	-	-	(1)	-	1
Impairment loss on manager and operating contracts	30	-	-	-	-
Impact of asset impairments recognized by subsidiaries	-	-	-	(5)	-
Obligation to EPCOR for Rossdale plant	-	-	-	2	-
Acquisition loss for Island Generation acquisition	-	-	6	-	-
Change in prior quarters' adjustments, for change in non-controlling percentage interest	-	-	1	-	-
Income tax adjustments	(2)	-	(1)	3	-
	30	9	8	(2)	9
Normalized earnings attributable to common shareholders	**3**	**11**	**5**	**14**	**1**
Normalized earnings per share	**$0.07**	**$0.33**	**$0.21**	**$0.64**	**$0.05**

Financial Position

In the second quarter of 2011, the Company announced the outcome of the strategic review related to CPILP, which resulted in the reclassification of the associated assets and liabilities as held for sale. In addition, the Company also completed the acquisitions of the New England facilities and Halkirk wind project (see Significant Events) in the second quarter of 2011. After removing the effects related to these events, the significant changes in the Consolidated Statements of Financial Position from December 31, 2010 to June 30, 2011 were as follows:

(unaudited, $millions) Increase (decrease)	June 30, 2011	Dec 31, 2010	Assets Held for Sale	Acquisitions	Other	Explanation of Other Increase (Decrease)
Accounts receivable and income taxes recoverable	218	286	(54)	19	(33)	Primarily due to lower customer energy consumption and customer contracts that expired in 2011, partly offset by higher income taxes recoverable.
Assets classified as held for sale	1,437	-	1,437	-	-	Reflects proposed sale of CPILP.
Intangible assets	267	651	(353)	43	(74)	Primarily due to impairment of the CPILP management and operations contracts, amortization and the impact of the strengthening Canadian dollar on the translation of intangible assets of U.S. subsidiaries.
Property, plant and equipment	3,619	3,678	(806)	629	118	Primarily due to capital expenditures partly offset by depreciation and the impact of the strengthening Canadian dollar on the translation of property, plant and equipment of U.S. subsidiaries.
Net derivative instruments assets (liabilities)	(28)	14	56	(10)	(88)	Primarily due to decreases in the fair value of derivative power contracts.
Accounts payable and accrued liabilities	220	282	(47)	26	(41)	Primarily due to lower accruals for energy purchases resulting from lower customer energy consumption and customer contracts that expired in 2011.
Liabilities classified as held for sale	886	-	886	-	-	Reflects proposed sale of CPILP.
Loans and borrowings (including current portion)	1,734	1,869	(667)	-	532	Primarily due to the debt offerings completed during the second quarter of 2011 as discussed under Significant Events, partly offset by the impact of the strengthening Canadian dollar on the translation of U.S. dollar denominated debt.
Provisions (including current portion)	175	175	(40)	-	40	Primarily due to the recognition of an asset retirement obligation relating to the New England plants.
Share Capital	1,048	820	-	-	228	Primarily due to the issuance of common share capital in March 2011.
Non-controlling interests	1,687	1,779	-	-	(92)	Non-controlling interests' share of CPLP and CPILP distributions and CPLP's and CPILP's other comprehensive loss, partly offset by non-controlling interests' share of CPLP and CPILP net income.

Liquidity and Capital Resources

(unaudited, $millions) Cash inflows (outflows)	Six months ended June 30 2011	2010	Change
Operating activities	168	159	9
Investing activities	(828)	(110)	(718)
Financing activities	664	(12)	676

Operating activities:

See Funds from Operations.

Investing activities:

The increase in cash used in investing activities primarily reflects the acquisitions of the New England facilities and the Halkirk wind project (discussed under Significant Events) as well as higher construction activity on the Quality Wind and Port Dover & Nanticoke projects. Cash used in investing activities for the six months ended June 30, 2010 was partly offset by cash proceeds from the sale of the Battle River PPA compared with no asset sales in the corresponding period in 2011.

Financing activities:

The cash flows from financing activities in the six months ended June 30, 2011 primarily reflected proceeds from the $300 million debt offering and the US$295 million private placement of senior notes as described under Significant Events, and the Company's $232 million common share offering in March 2011, partly offset by debt repayments of $33 million to EPCOR. In the corresponding period in 2010, the Company issued $335 million of debt and made $245 million of debt repayments to EPCOR which were financed with draws on credit facilities.

On June 30, 2011, CPLP had $1,220 million of credit facilities, of which $841 million remained available as CPLP had $238 million of long-term debt and $141 million of letters of credit outstanding under the facilities. CPLP made a net draw of $21 million in the six months ended June 30, 2011, under its revolving credit facilities. In addition, Capital Power Corporation had an undrawn bank line of credit of $5 million.

CPLP's available credit facilities will provide it with adequate funding for ongoing development projects and the $201 million of principal debt repayments due in the next twelve months.

On June 30, 2011, CPILP had credit facilities of approximately $364 million, of which $265 million remained available as CPILP had $69 million of long-term debt and $30 million of letters of credit outstanding under the facilities. CPILP made a net repayment of $17 million in the six months ended June 30, 2011, under its credit facilities.

CPLP has received a corporate credit rating of BBB from S&P. On June 28, 2011, S&P reaffirmed the corporate rating but revised its outlook from stable to negative based on their view that CPLP's growth plan could weaken its satisfactory business risk profile over time while its execution requires supportive capital market conditions. Management remains committed to maintaining a BBB rating and is taking actions to address the concerns raised by S&P. The BBB rating assigned by S&P is the fourth highest rating of S&P's ten corporate credit ratings. According to S&P, a BBB corporate credit rating exhibits adequate capacity to meet financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.

CPLP has received a long-term debt credit rating of BBB from DBRS. The BBB rating assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities.

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

Capital Expenditures

(unaudited, $millions)	2011		Total project		
	Six months ended June 30	Full year estimate[1]	Incurred to June 30, 2011[2]	Total cost estimate[1]	Expected completion date
CPLP					
Keephills 3	$ 52	$ 88	$ 944	$ 980	3rd quarter 2011
Quality Wind	45	148	68	455	4th quarter 2012
Port Dover & Nanticoke	21	54	44	340	4th quarter 2012
Halkirk	51	190	51	357	2nd half 2012
Sustaining	34	98			
Total CPLP	203	578			
CPILP					
North Carolina plants enhancement	2	5	93	96	2011
Maintenance capital	11	25			
Total CPILP	13	30			
Total capital expenditures[3]	216	608			
Emission credits	17				
Less capitalized interest	(24)				
Payments to acquire property plant and equipment and other assets	209				

(1) Capital expenditures to be incurred over the life of the project and in the twelve months ended December 31, 2011 are based on management's estimates.

(2) Total project capital expenditures incurred to June 30, 2011 reflect capital expenditures incurred since the inception of the project.

(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.

During the first quarter of 2011, the Company revised its expectation for the commercial operation date of Keephills 3 to move to the third quarter of 2011, later than previous expectations of the second quarter, which is expected to add approximately $20 million to $30 million or 2% to 3% in capital costs of the Company's share of the project.

Construction of the Quality Wind project remains on target to the project cost forecast and schedule. Construction of the Port Dover & Nanticoke project was delayed by completion of the land title transfers which resulted in $44 million of expenditures planned for 2011 being deferred to 2012. The delay is not expected to impact the planned completion date or total cost of the project.

In the second quarter of 2011, the Company acquired the Halkirk wind project as discussed under Significant Events. The expenditures incurred to date primarily reflect $33 million for permits and land lease rights and an $18 million payment to the supplier of the wind turbines.

Sustaining capital expenditures include spending on plant maintenance, the Genesee mine, information technology for a new energy trading and risk management system, and leasehold improvements for offices in Calgary and Edmonton. The full year estimate was updated in the second quarter of 2011 to add $8 million for land purchases for the Genesee mine.

Future cash requirements – excluding CPILP

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 the six months ended December 31, 2011, excluding CPILP's cash requirements and cash requirements for acquisitions, are expected to include approximately $375 million for capital expenditures, approximately $30 million for CPLP distributions to EPCOR, subject to approval by the CPLP Board of Directors approximately $31 million for Capital Power's quarterly common share dividends, subject to approval by the Capital Power Corporation Board of Directors, and approximately $3 million for its quarterly preferred share dividends.

The current portion of long-term debt on the statement of financial position of $201 million is primarily comprised of $200 million payable to EPCOR in November 2011.

The Company expects to fund the construction of the Quality Wind, Port Dover & Nanticoke and Halkirk wind projects using existing bank credit facilities. Once construction is complete, the Company expects to put long-term financing in place while maintaining the Company's overall leverage in the range of 40% to 50%. The Company's other cash requirements identified above, are expected to be funded with cash on hand, cash provided by operating activities, use of existing bank credit facilities, and proceeds from the equity offering completed in July 2011 and disposition of the interest in CPILP. See Significant and Subsequent Events.

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 at the time of a requirement for a major investment of capital. Under the short form base shelf prospectuses, Capital Power may raise up to $1 billion by issuing common 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 $316 million of equity and $400 million of debt available under these short form base shelf prospectuses. Both shelf prospectuses expire in May 2012.

Future cash requirements – CPILP

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. CPILP's estimated cash requirements for the six months ended December 31, 2011 are expected to include approximately $17 million for capital expenditures, approximately $50 million for distributions subject to approval by the CPILP Board of Directors and approximately $7 million for preferred share dividends of a subsidiary company. In conjunction with CPILP's agreement with Atlantic Power to sell its partnership units, as discussed under Significant Events CPILP announced the termination of its distribution reinvestment program. If CPILP's total cash requirements for the remainder of 2011 remain as planned, it is expected that the sources of capital will be cash on hand, cash provided by operating activities and use of existing credit facilities.

CPILP's short form base shelf prospectus, market conditions permitting, provides the partnership with the ability to obtain new debt and equity capital from external markets at an aggregate amount of up to $600 million. This base shelf prospectus expires in August 2012.

Financial market stability remains an issue and if instability in the Canadian and U.S. financial markets were to return, it may adversely affect Capital Power's ability to raise new capital, to meet its financial requirements and to refinance indebtedness under existing credit facilities and debt agreements at their maturity dates. In addition, Capital Power has credit exposure with a number of counterparties to various agreements, most notably its PPA, trading and supplier counterparties. While the Company continues to monitor its exposure to its significant counterparties, there can be no assurance, particularly in light of the current economic environment, that all counterparties will be able to meet their commitments.

Contractual Obligations

The material changes to the Company's commitments since December 31, 2010 include those related to the $300 million medium-term notes issued in April 2011, the US$295 million private placement of senior notes issued in June 2011, the sale of its interest in CPILP and the development of the Halkirk project, as described under Significant Events. Otherwise, there were no changes to the Company's purchase obligations, commitments or contingencies since December 31, 2010, including payments for the next five years and thereafter, that would be material to the Company's business or financial position. For further information on these obligations, refer to the Company's December 31, 2010 MD&A.

Off-balance Sheet Arrangements

As at June 30, 2011, the Company had no off-balance sheet arrangements.

Related Party Transactions

EPCOR, including its subsidiaries, and its sole shareholder The City of Edmonton, are the only related parties with which the Company had material transactions in the six months ended June 30, 2011. At June 30, 2011, EPCOR owned 47.416 million exchangeable limited partnership units of CPLP and 47.416 million accompanying special voting shares and one special limited voting share in the capital of Capital Power Corporation.

The Company's long-term debt payable to EPCOR, which was issued in connection with the Reorganization, was $584 million at June 30, 2011 compared with $619 million at December 31, 2010.

The Company's related party transactions for the six months ended June 30, 2011 and June 30, 2010 were as follows:

(unaudited, $ millions)		Six months ended June 30, 2011	Six months ended June 30, 2010
Statement of Income (Loss)			
Revenues	(a)	$ 251	$ 189
Energy purchases and fuel	(b)	10	13
Net financing expense	(c)	11	8

[a] Included in the Company's revenues are power sales to EPCOR, including its subsidiaries, and the City of Edmonton for resale to its customers. For the six months ended June 30, 2011, the Company had $234 million of power sales to EPCOR and its subsidiaries, and $17 million to the City of Edmonton. For the six-month period in 2010, the Company had $175 million and $14 million of power sales to EPCOR and the City of Edmonton, respectively.

[b] The Company purchased distribution and transmission services from EPCOR and had various transactions with EPCOR pursuant to the agreements which provide for the continuity of operations and services following the separation of the business of Capital Power from EPCOR.

[c] For the six months ended June 30, 2011 and 2010, $10 million and $22 million, respectively, of the interest incurred on the long-term debt payable to EPCOR was capitalized as property, plant and equipment for construction work in progress. The remainder was included in net financing expense.

All of the above transactions were in the normal course of operations and were recorded at the exchange values which were based on normal commercial rates.

Business Risks

There have been no material changes in the six months ended June 30, 2011 to the Company's business and operational risks as provided in the Company's December 31, 2010 MD&A.

International Financial Reporting Standards

Capital Power's June 30, 2011 condensed interim consolidated financial statements are prepared in accordance with International Accounting Standard (IAS) 34 Interim Financial Reporting. The comparative periods included in these financial statements have been restated to IFRS and the Company has applied IFRS 1 First-time Adoption of International Financial Reporting Standards. The Company's previously issued interim and financial reports for periods prior to and including the year ended December 31, 2010, were prepared in accordance with previous CGAAP.

The following tables provide a summary of principal adjustments made by the Company in restating its previously published Canadian GAAP financial statements for the three and six months ended June 30, 2010. Optional exemptions and exceptions were applied and discussed in the March 31, 2011 condensed interim consolidated financial statements and MD&A.

Equity

(unaudited, $millions)	As at June 30, 2010		
	Attributable to shareholders	Attributable to Non-controlling interests	Total equity
Previous CGAAP	479	2,026	2,505
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	(3)	(14)	(17)
IAS 36 Impairments	(5)	(44)	(49)
IFRS 1 First time adoption of IFRS	4	48	52
Other impacts	8	85	93
IFRS	483	2,101	2,584

Total comprehensive income

(unaudited, $millions)	Three months ended June 30, 2010		
	Attributable to shareholders	Attributable to non-controlling interests	Total comprehensive income
Previous CGAAP	(10)	(17)	(27)
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	-	5	5
IAS 36 Impairments	-	(1)	(1)
IFRS 1 First time adoption of IFRS	1	2	3
Other impacts	(1)	(2)	(3)
IFRS	(10)	(13)	(23)

(unaudited, $millions)	Six months ended June 30, 2010		
	Attributable to shareholders	Attributable to non-controlling interests	Total comprehensive income
Previous CGAAP	3	43	46
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	(2)	(3)	(5)
IAS 36 Impairments	1	-	1
IFRS 1 First time adoption of IFRS	-	(1)	(1)
Other impacts	-	(1)	(1)
IFRS	2	38	40

IAS 16 Property, plant and equipment (PP&E)

IFRS are more specific with respect to the level at which components of assets are to be accounted for. The appropriate components have been identified and the most significant difference from previous CGAAP is that overhaul costs are capitalized under IFRS. Additionally, certain costs relating to the Genesee mine that were previously capitalized under CGAAP have been expensed under IFRS due to componentization. The contract between the Genesee mine operator and the Company requires Capital Power to fully fund the operating activities of the mine, including depreciation, whereas capital asset funding is shared between the two parties. As a result, certain costs that were previously capitalized would have been expensed under the requirements of IAS 16 and fully funded by Capital Power. This has resulted in the Company recording transitional adjustments to recognize deferred revenue and other liabilities and to align the two parties' accounting policies.

IAS 37 Provisions

In accordance with IAS 37, provisions are required to be measured at the best estimate of the expected expenditure, such as for an asset retirement, using discount rates appropriate for each liability. Under previous CGAAP such provisions were measured at fair value. Under IFRS, provisions are re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Company re-measured its provisions using revised cash flow estimates for the Genesee mine asset retirement obligation, and revised discount rates for all of its plant decommissioning liabilities. The Company also re-measured amounts provided for the unavoidable costs of its Alberta retail and commercial natural gas contracts using revised cash flow and discount rate assumptions.

IAS 36 Impairments

In accordance with IAS 36, as discussed in the March 31, 2011 MD&A, the Company reviewed the recoverable amount for its cash generating units (CGUs) for which goodwill was required to be allocated, at both the date of transition to IFRS and as at December 31, 2010. For all other CGUs, management assessed whether there were any events at the date of transition to IFRS, at June 30, 2010 and at December 31, 2010 which would require an assessment for impairment. Recoverable amounts were calculated on a fair value less cost to sell basis, using discounted cash flow models based on the Company's long-term planning model. This one step approach, at the CGU level, under IFRS differs from the two-step approach under previous CGAAP, which required the application of discounted cash flow techniques to measure the impairment amount, but only after the use of undiscounted cash flow analysis indicated the existence of an impairment. Some CGUs consist of a single plant resulting in more CGUs subject to impairment testing under IFRS than under previous CGAAP.

As a result of the changes to the determination of recoverable amounts and the allocation of the goodwill to the CGUs, the Company recognized $50 million of impairments as at June 30, 2010. These impairments included $43 million for certain CPILP facilities due to the impact of weakening economic conditions in their respective markets and $7 million for the Company's management contracts with CPILP.

IFRS 1 First time adoption of IFRS

The Company elected under IFRS 1 to use fair value as the deemed cost of its PP&E for certain plants. As a result, the June 30, 2010 PP&E balance increased by $52 million. Net income decreased by $1 million and $2 million for the three and six months ended June 30, 2010 respectively, due to higher depreciation and amortization on the increased PP&E balances.

IFRS 1 also provides for an election to deem any cumulative translation differences to be zero on transition to IFRS. As a result of the Company taking the IFRS 1 election to adjust the balance of its cumulative translation account to nil at the date of transition, $4 million was reclassified within equity, from accumulated other comprehensive income to retained earnings at January 1, 2010.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in an increase of $4 million in the equity attributable to shareholders and an increase of $48 million to non-controlling interests as at June 30, 2010.

Other impacts

In accordance with IAS 17 Leases, the Kingsbridge PPA was determined to be a finance lease as IAS 17 and had different qualitative guidelines than previous CGAAP in the determination of the classification of leases between operating and finance (or capital under previous CGAAP), resulting in a decrease in PP&E of $51 million, an increase in finance lease receivable of $62 million, an increase in trade and other receivables of $2 million and an increase in retained earnings of $13 million as at June 30, 2010.

In accordance with IAS 31 Interests in Joint Ventures, the Company controls the Genesee mine joint venture and as a result the Company consolidated the non-controlling interest's share of the Genesee mine assets resulting in an increase in PP&E and non-controlling interests of $86 million as at June 30, 2010.

In accordance with IAS 39, hedge effectiveness testing must incorporate the Company's credit risk, which resulted in an increase of $1 million in accumulated other comprehensive income as at June 30, 2010, with a corresponding decrease in retained earnings.

Other impacts in the tables above also include the tax impact of the adjustments recognized.

Future Accounting Changes

A number of new standards, and amendments to standards and interpretations, are not yet effective for the quarter ended June 30, 2011 and have not been applied in preparing the unaudited condensed interim consolidated financial statements. The following standards and interpretations have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee effective for annual periods starting on or after their effective dates as follows:

International Accounting Standards (IAS/IFRS)	Effective Date
IAS 12 - Income Taxes	January 1, 2012
IAS 1 – Presentation of Financial Statements	July 1, 2012
IFRS 9 - Financial Instruments	January 1, 2013
IFRS 10 – Consolidated Financial Statements	January 1, 2013
IFRS 11 – Joint Arrangements	January 1, 2013
IFRS 12 – Disclosures of Interests in Other Entities	January 1, 2013
IFRS 13 – Fair Value Measurement	January 1, 2013
IAS 19 – Employee Benefits	January 1, 2013

The amendments to IAS 12 relate to the measurement of deferred taxes for investment property, PP&E and intangible assets carried at fair value.

The amendments to IAS 1 provide improvements to the presentation of components of other comprehensive income. It requires entities to group items within other comprehensive income that may be reclassified to profit or loss.

IFRS 9 applies to the classification and measurement of financial assets and financial liabilities. It is the first of three phases of a project to develop standards to replace IAS 39 - Financial Instruments and was initiated in response to the crisis in financial markets.

IFRS 10 replaces IAS 27 Consolidated and Separate Financial Statements and SIC – 12 Consolidation – Special Purpose Entities. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. It provides a single consolidation model that identifies control as the basis for consolidation for all types of entities. IFRS 12 provides comprehensive disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and special purpose vehicles.

IFRS 11 supersedes IAS 31 – Interests in Joint Ventures and SIC 13 – Jointly Controlled Entities – Non-Monetary Contributions by Venturers. The standard requires a single method to account for interests in jointly controlled entities. All joint ventures are required to be recognized as an investment and be accounted for on an equity basis.

IFRS 13 defines fair value, sets out in a single IFRS a framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies when other IFRSs require or permit fair value measurements. It does not introduce any new requirements to measure an asset or a liability at fair value, change what is measured at fair value in IFRSs or address how to present changes in fair value.

The amendments to IAS 19 relate to the recognition and disclosure requirements for defined benefit plans and result in the following key changes: (a) to eliminate the corridor method that defers the recognition of gains and losses, (b) to streamline the presentation of changes in assets and liabilities arising from defined benefit plans, and (c) to enhance the disclosure requirements for defined benefit plans.

The Company is currently assessing the extent of the impact of adopting these standards and interpretations on its consolidated financial statements.

Critical Accounting Estimates and Policies

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the Company's most significant accounting policies and the items for which critical estimates were made in the financial statements: revenue recognition under PPAs, financial instruments, non-financial assets, provisions, income taxes, leases or arrangements containing a lease, foreign currency translation, purchase price allocations for acquisitions and the consolidation of CPILP, CPLP and Genesee coal mine. For further information on the Company's accounting policies and estimates, refer to the Company's December 31, 2010 and March 31, 2011 MD&A.

Financial Instruments

The Company's derivative instruments assets and liabilities used for risk management purposes are measured at fair value and consist of the following:

(unaudited, $millions)	Energy cash flow hedges	Energy non-hedges	Foreign exchange non-hedges	Interest rate non-hedges	Total
Total derivative instruments net assets (liabilities) as at June 30, 2011	(121)	1	36	-	(84)
Less: Derivative instruments net assets (liabilities) held by CPILP and reclassified to assets held for sale	(91)	(2)	37	-	(56)
Net derivative instruments net assets (liabilities) as at June 30, 2011	(30)	3	(1)	-	(28)

As a result of the outcome of the CPILP Strategic Review as discussed under Significant Events, certain assets and liabilities relating to the Company's interest in CPILP were reclassified as assets and liabilities held for sale at June 30, 2011. Accordingly, the following explanations relate to the derivative instrument balances after the reclassification.

At June 30, 2011, the fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of $30 million which primarily reflected the impact of increased forward Alberta power prices on power derivative contracts relative to the contract prices.

At June 30, 2011, the fair value of energy derivative instruments not designated as hedges for accounting purposes was a net asset of $3 million, which primarily reflected the impact of changes in the forward Alberta power prices on the Alberta power portfolio.

The Company entered into forward bond sale contracts in the first quarter of 2011 to hedge exposure to interest rate risk on the issue of long-term debt in the second quarter of 2011. The contracts were settled in the second quarter of 2011.

For the six months ended June 30, 2011 and June 30, 2010, losses net of income taxes on derivative instruments designated as cash flow hedges, of $74 million and $17 million respectively, were recorded in other comprehensive income for the effective portion of cash flow hedges. Realized losses, net of income taxes, for the six months ended June 30, 2011 of $16 million and gains, net of income taxes, for the six months ended June 30, 2010 of $11 million were reclassified to energy purchases and revenues as appropriate. For the six months ended June 30, 2011 and June 30, 2010, the change in the fair value of the ineffective portion of hedging derivatives recognized in the statement of income, before non-controlling interests, was a loss of $2 million and $1 million, respectively.

Internal Control over Financial Reporting

There were no changes in the Company's internal controls over financial reporting that occurred during the six months ended June 30, 2011 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting. The Company's transition to IFRS did not result in any significant changes to the Company's internal controls.

Forward-looking Information

Certain information in this MD&A is forward-looking within the meaning of Canadian securities laws as it relates to anticipated financial performance, events or strategies. When used in this context, words such as will, anticipate, believe, plan, intend, target, and expect or similar words suggest future outcomes. By their nature, such statements are subject to significant risk, assumptions and uncertainties, which could cause Capital Power's actual results and experience to be materially different than the anticipated results.

Forward-looking information in this MD&A includes, among other things, information relating to: (i) expectations for the Company's and CPILP's sources of capital and use, adequacy and availability of committed bank credit facilities and potential future borrowings; (ii) the Company's and CPILP's cash requirements for 2011, including interest and principal repayments, capital expenditures, distributions and dividends; (iii) expectations that the contracted plants will contribute approximately 50% of the Company's EBITDA; (iv) expectations regarding future growth and emerging opportunities in the Company's target markets including the focus on certain technologies and the division between contracted versus merchant facilities; (v) expectations regarding the Company's planned divestitures of the Miller Creek, Brown Lake, and Taylor Coulee Chute facilities; (vi) expectations regarding the Company's portfolio following the planned divestiture of its interest in CPILP; (vii) expectations regarding the Company's target markets and geographic focus and the division between contracted and merchant facilities in the respective geographic markets; (viii) expectations regarding the scope of opportunities for contracted assets and merchant plants in the Company's target markets; (ix) expectations that the New England plant and Halkirk Wind project acquisitions will contribute to a balanced portfolio of contracted and merchant assets, will meet or exceed the target rate of return and will grow the target markets; (x) expectations regarding the timing of filing and the amount of the business interruption insurance claim for Clover Bar Energy Centre Unit 3; (xi) expected timing of the outage at Clover Bar Energy Centre Unit 2 in 2011; (xii) expectations regarding plant availability in 2011; (xiii) expectations regarding the commercial operation date of Keephills 3 and the impact of the delay in commercial operation date of Keephills 3 on capital costs; (xiv) expectations regarding normalized earnings per share and expectations regarding full year normalized earnings in 2011; (xv) expected impact on capitalization and full year depreciation as a result of maintenance costs which are capitalized under IFRS; (xvi) the expected impact on depreciation as a result of the extension in useful life of the Genesee and Keephills 3 plants; (xvii) expected impact on earnings as a result of the three New England plant acquisitions in 2011; (xviii) expected impact on financing costs due to the issuance of the medium-term notes debentures in April 2011 and the private placement of senior notes in June 2011; (xix) expectations regarding the ability to attain the goal of 10,000 MW of owned or operated generation capacity by 2020; (xx) expectations regarding the impact of the new PPAs at the Southport and Roxboro facilities on EBITDA and capitalized maintenance costs; (xxi) expectations regarding the outcome of the CPILP strategic review and the agreement with Atlantic Power pursuant to which Atlantic will acquire all of the outstanding limited partnership units of CPILP, Capital Power will acquire CPILP's Roxboro and Southport plants, and Capital Power will cease to manage CPILP; (xxiii) expectations regarding the timing of closing of the CPILP strategic review transactions, total consideration to be received, including disposal costs to be incurred and use of cash consideration, and the gain on sale and foreign translation loss attributable to common shareholders, to be recognized in connection with the CPILP strategic review transaction in the fourth quarter; (xxiv) expectations regarding the commercial operation date of the Halkirk wind project, the total cost of the project, the impact on annual earnings per share for the first five years of operations, the after-tax internal rate of return over the life of the assets, and the total number of turbines the project will incorporate; (xxv) expectations regarding the source of Halkirk's revenues and that 40% to 45% is expected to come from the sale of renewable energy credits; (xxvi) expectations that revenues from New England power plants will include payments for capacity, energy, and ancillary services at market-based rates; (xxvii) expectations regarding timing of spending on the Port Dover & Nanticoke project and the impact on the commercial operation date and total project cost; (xxiii) expected funding of the Quality Wind, Port Dover & Nanticoke, and Halkirk wind projects during construction and once completed while maintaining overall leverage in the range of 40% - 50%; (xxix) expected total capital project costs and capital expenditures as well as expected project completion dates and expected payments under contractual obligations; (xxx) expectations regarding Alberta power prices for 2011; (xxxi) expectations regarding total contribution of the New England plant and Halkirk acquisitions to the Company's committed capital in 2011; (xxxii) expectations regarding the Company's ability to develop networked hubs in its three U.S. target markets and Alberta; (xxxiii) expectations regarding future pension valuation adjustments; and (xxxiv) expectations regarding future interest payments.

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 include, but are not limited to: (i) the operation of the Company's facilities; (ii) power plant availability and dispatch, including Sundance which is subject to an acquired PPA; (iii) the Company's financial position and credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets, including power prices and forward power prices for 2011; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) weather; (vii) availability and cost of labour and management resources; (viii) performance of contractors and suppliers; (ix) availability and cost of financing; (x) foreign exchange rates; (xi) management's analysis of applicable tax legislation; (xii) currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; (xviii) ability to obtain necessary regulatory approvals for development projects; (xix) the Company's assessment of capital markets, common share ownership distribution, and ability to complete future share and debt offerings; (xx) locations of projects and the areas of which they will be developed, including the availability and use of certain optioned lands; (xxi) costs of construction and development; (xxii) current risk management strategies including hedges will be in place; (xxiii) total cash requirements; (xxiv) ability to obtain court and regulatory approvals, and unitholders' and shareholders' favourable votes in relation to the CPILP strategic review transaction; (xxv) carrying amounts of assets held for sale; and (xxvi) factors and assumptions noted under Outlook in respect of the forward looking statements and information noted in that section.

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 risks and uncertainties include, but are not limited to, risks relating to: (i) operation of the Company's facilities; (ii) power plant availability and performance, including unplanned plant outages at facilities of other market participants; (iii) unanticipated maintenance and other expenditures; (iv) availability and price of energy commodities; (v) electricity load settlement; (vi) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (vii) weather and economic conditions; (viii) competitive pressures; (ix) construction; (x) availability and cost of financing; (xi) foreign exchange; (xii) availability and cost of labour, equipment and management resources; (xiii) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; (xiv) developments in the North American capital markets; (xv) compliance with financial covenants; (xvi) ability to successfully realize the benefits of acquisitions, investments and divestitures; (xvii) the tax attributes of and implications of any acquisitions; (xviii) the completion of the CPILP strategic review transactions; (xix) ability to secure new contracts and terms of such contracts; (xx) risks and uncertainties noted under Outlook in respect of the forward looking information and statements noted in that section. See also Business Risks in the Company's December 31, 2010 annual MD&A. If any such risks actually occur, they could materially adversely affect the Company's business, financial condition or results of operations. In that case the trading price of the Company's common shares could decline, perhaps materially.

This MD&A includes the following updates to previously disclosed forward-looking statements: (i) The corporate strategy has been updated to include 1) a change in the target return for contracted assets from 9% to 8% 2) a change in technological focus to merchant and contracted natural gas facilities and contracted renewable energies facilities including solar development and acquisitions, while biomass and hydro technologies will no longer be pursued, and 3) expanded geographical focus for contracted wind and natural gas opportunities in the Pacific North West and Saskatchewan, while in the Mid-Atlantic and U.S. South West markets only contracted opportunities are expected to be pursued; (ii) the full year sustaining capital estimate has been updated to add $8 million for land purchases for the Genesee mine; (iii) expectations regarding normalized earnings per share have been updated to include revised expectations regarding Alberta power prices in 2011 and the impact of the loss on the settlement of bond forward contracts and the pension adjustment; (iv) the outage at Clover Bar Energy Centre Unit 2 has been rescheduled from the summer of 2011 to November and December 2011; and (v) the earnings contribution from the three New England plants for 2011 has been updated to include an additional $2 million for a Connecticut energy tax which was introduced in June 2011.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. Forward-looking statements are provided for the purpose of providing information about management's current expectations, and plans relating to the future. Readers are cautioned that such information may not be appropriate for other purposes. 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.

Quarterly Information

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, planned and unplanned plant outages, as well as items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's derivative power, natural gas, foreign exchange and forward bond sale contracts, and natural gas held for trading.

Financial highlights

(unaudited, $millions except earnings (loss) per share)	Three months ended							
	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009(3)	Sept 30, 2009(3)
Revenues and other income(2)	472	458	437	511	313	501	497	511
Gross income	217	167	205	233	117	217	216	218
EBITDA(1)	65	82	96	80	37	169	116	140
Net income (loss)	(22)	14	22	(3)	(34)	92	39	80
Net income (loss) attributable to shareholders	(25)	3	(3)	16	(8)	12	7	14
Earnings (loss) per share	$(0.67)	$0.06	$(0.13)	$0.73	$(0.37)	$0.55	$0.33	$0.64
Normalized earnings per share(1)	$0.07	$0.33	$0.21	$0.64	$0.05	$0.51	$0.18	$0.42

(1) The consolidated financial information, except for EBITDA and normalized earnings per share, has been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

(2) Revenues for the three months ended September 30, 2009 have been restated for a reclassification which resulted in a reduction in each of revenue and energy purchases by $14 million. The restatement had no impact on gross income, EBITDA or net income and the presentation is consistent with subsequent periods.

(3) The results for the third and fourth quarters of 2009 have been prepared in accordance with previous CGAAP.

Generation volume and plant availability information

(unaudited, GWh)	Three months ended							
Electricity generation[1]	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants								
Genesee 3	477	482	272	475	432	483	484	470
Keephills 3[2]	50	-	-	-	-	-	-	-
Joffre	57	98	82	67	93	41	73	89
Clover Bar Energy Centre 1, 2 and 3	40	162	179	37	102	43	9	16
Taylor Coulee Chute	2	-	1	7	3	-	2	12
Clover Bar Landfill Gas	9	8	9	9	10	10	10	9
Weather Dancer[3]	-	-	-	-	-	-	-	-
	635	750	543	595	640	577	578	596
Alberta contracted plants								
Genesee 1	661	768	854	841	780	813	618	837
Genesee 2	789	831	826	824	571	825	817	801
	1,450	1,599	1,680	1,665	1,351	1,638	1,435	1,638
Ontario and British Columbia contracted plants								
Kingsbridge 1	24	31	39	18	22	26	32	14
Miller Creek	26	5	7	46	35	7	14	47
Brown Lake	15	14	14	5	11	13	15	11
Island Generation	55	52	273	-	-	-	-	-
	120	102	333	69	68	46	61	72
North East U.S. commercial plants[4]								
Rumford	68	-	-	-	-	-	-	-
Tiverton	289	-	-	-	-	-	-	-
Bridgeport	645	-	-	-	-	-	-	-
	1,002	-	-	-	-	-	-	-
Total plants excluding CPILP plants	**3,207**	**2,451**	**2,556**	**2,329**	**2,059**	**2,261**	**2,074**	**2,306**
CPILP plants	1,155	1,139	1,311	1,306	1,128	1,268	1,407	1,228
Total plants	**4,362**	**3,590**	**3,867**	**3,635**	**3,187**	**3,529**	**3,481**	**3,534**

(1) Electricity generation reflects the Company's share of plant output.

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

(3) The Weather Dancer facility was divested in the second quarter of 2011.

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

(unaudited)	Three months ended							
Generation plant availability[1]	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants								
Genesee 3	100%	100%	56%	99%	96%	100%	99%	97%
Joffre	78%	99%	99%	98%	84%	100%	94%	96%
Clover Bar Energy Centre 1, 2 and 3	65%	65%	95%	63%	52%	72%	98%	96%
Taylor Coulee Chute	94%	100%	100%	100%	90%	98%	66%	100%
Clover Bar Landfill Gas	86%	95%	88%	92%	96%	96%	94%	90%
Weather Dancer[2]	-	0%	0%	0%	0%	83%	0%	55%
	82%	87%	83%	86%	76%	90%	97%	96%
Alberta contracted plants								
Genesee 1	81%	92%	100%	100%	100%	99%	74%	100%
Genesee 2	99%	100%	97%	97%	75%	99%	97%	95%
	90%	96%	98%	99%	87%	99%	85%	97%
Ontario and British Columbia contracted plants								
Kingsbridge 1	99%	98%	100%	99%	100%	99%	100%	99%
Miller Creek	99%	78%	12%	96%	96%	37%	97%	88%
Brown Lake	99%	100%	99%	93%	99%	97%	99%	97%
Island Generation	100%	99%	99%	-	-	-	-	-
	100%	97%	91%	97%	98%	74%	99%	94%
North East U.S. commercial plants[3]								
Bridgeport	100%	-	-	-	-	-	-	-
Rumford	99%	-	-	-	-	-	-	-
Tiverton	97%	-	-	-	-	-	-	-
	99%	-	-	-	-	-	-	-
Average excluding CPILP plants[4]	**91%**	**93%**	**91%**	**93%**	**83%**	**93%**	**92%**	**97%**
CPILP plants[4]	88%	92%	97%	97%	90%	95%	92%	93%
Average all plants[4]	**90%**	**92%**	**95%**	**95%**	**86%**	**94%**	**92%**	**95%**

(1) 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.

(2) The Weather Dancer facility was divested in the second quarter of 2011.

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

(4) Average generation plant availability is an average of individual plant availability weighted by owned or operated capacity.

The Company's target for plant availability excluding CPILP plants for 2011 is 94%. In the second quarter of 2011, 91% was achieved for this performance measure, reflecting the outage at Clover Bar Energy Centre Unit 3 which has been offline since January 15, 2011 due to blade damage in its high pressure compressor.

Results by plant category

(unaudited, $millions)	Three months ended							
	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009[3]	Sept 30, 2009[3],[4]
Revenues and other income								
Alberta commercial plants and portfolio optimization	$ 215	$ 266	$ 237	$ 247	$ 197	$ 235	$ 248	$ 238
Alberta contracted plants	64	77	76	72	57	73	61	70
Ontario/British Columbia contracted plants	13	13	12	3	3	3	4	4
North East U.S. commercial plants and portfolio optimization [1]	51	-	-	-	-	-	-	-
CPILP plants	129	128	139	130	116	139	130	123
Other portfolio activities	18	34	26	19	22	43	40	23
Corporate	6	6	6	7	10	6	-	-
Inter-plant category transaction eliminations	(17)	(20)	(15)	(16)	(18)	(15)	(9)	(10)
	479	504	481	462	387	484	474	448
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading								
- CPLP	(8)	(49)	(55)	38	(55)	12	15	30
- CPILP	1	3	11	11	(19)	5	8	33
	(7)	(46)	(44)	49	(74)	17	23	63
	$ 472	**$ 458**	**$ 437**	**$ 511**	**$ 313**	**$ 501**	**$ 497**	**$ 511**
Gross income								
Alberta commercial plants and portfolio optimization	$ 57	$ 50	$ 58	$ 69	$ 59	$ 65	$ 53	$ 50
Alberta contracted plants	52	62	56	59	42	58	48	58
Ontario/British Columbia contracted plants	13	13	12	3	3	3	4	4
North East U.S. commercial plants and portfolio optimization [1]	15	-	-	-	-	-	-	-
CPILP plants	75	72	85	76	68	77	74	77
Other portfolio activities	9	9	3	13	6	15	12	8
Corporate	6	6	6	7	10	6	-	-
Inter-plant category transaction eliminations	(12)	(13)	(15)	(15)	(17)	(14)	(9)	(8)
	215	199	205	212	171	210	182	189
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading								
- CPLP	-	(34)	(14)	14	(36)	9	26	16
- CPILP	2	2	14	7	(18)	(2)	8	13
	2	(32)	-	21	(54)	7	34	29
	$ 217	**$ 167**	**$ 205**	**$ 233**	**$ 117**	**$ 217**	**$ 216**	**$ 218**
EBITDA[2]								
Alberta commercial plants and portfolio optimization	$ 44	$ 38	$ 45	$ 57	$ 46	$ 53	$ 42	39
Alberta contracted plants	35	47	41	46	29	44	25	45
Ontario/British Columbia contracted plants	10	10	8	2	2	2	3	3
North East U.S. commercial plants and portfolio optimization [1]	10	-	-	-	-	-	-	-
CPILP plants	37	45	39	(1)	43	49	39	48
Other portfolio activities	2	-	(5)	5	(5)	6	(1)	2
Corporate	(75)	(26)	(33)	(50)	(24)	(20)	(26)	(25)
Inter-plant category transaction eliminations	-	-	-	-	-	-	-	(1)
	63	114	95	59	91	134	82	111
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading								
- CPLP	-	(34)	(15)	14	(36)	9	26	16
- CPILP	2	2	14	7	(18)	(2)	8	13
	2	(32)	(1)	21	(54)	7	34	29
Gains on acquisitions and disposals	-	-	2	-	-	28	-	-
	$ 65	**$ 82**	**$ 96**	**$ 80**	**$ 37**	**$ 169**	**$ 116**	**$ 140**

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

(2) The results by plant category, except for EBITDA, have been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

(3) The results for the third and fourth quarter of 2009 have been prepared in accordance with previous CGAAP.

(4) Revenues and energy purchases for the third quarter of 2009 have been restated. See Quarterly Information - Financial Highlights.

(unaudited, $/MWh)	Three months ended							
Alberta power prices	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009	Sept 30, 2009
Average Alberta power spot price	$52	$ 82	$ 46	$ 36	$ 81	$ 41	$ 46	$ 50
Capital Power's Alberta portfolio's average realized power price	56	64	64	66	66	67	57	54

Factors impacting the 2011 second quarter results

Alberta commercial plants and portfolio optimization EBITDA was lower in the second quarter of 2011 primarily due to significant increases in Alberta power prices in the second half of June as a result of unplanned and forced outages in the region which had an unfavourable impact on the Company's portfolio position.

Alberta contracted plants EBITDA included $5 million of availability incentive penalties relating to a scheduled maintenance outage at Genesee 1 in the second quarter of 2011.

North East U.S. commercial plants and portfolio optimization EBITDA reflected contributions from the Rumford, Tiverton and Bridgeport facilities and trading in the North East U.S. power market since their acquisition in April 2011. See Significant Events.

Corporate general and administrative expenses for the second quarter of 2011 included an impairment loss of $43 million on Capital Power's management and operations contracts with CPILP as described under Significant Events. Corporate expenses also increased for an adjustment to the Company's supplemental pension obligation based on an actuarial valuation.

Finance expense for the second quarter of 2011 included a $10 million loss related to the settlement of forward bond sale contracts.

Factors impacting results for the previous quarters

Significant items which impacted results for the previous quarters were as follows:

In the first quarter of 2011, the average Alberta power price increased significantly primarily due to colder weather than normal and the shut down 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 power spot 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. In December 2010, a subsidiary of EPCOR exchanged 9,209,000 of its exchangeable limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis reducing EPCOR's ownership interest in CPLP to approximately 60.5% from its initial interest of 72.2%.

In the third quarter of 2010, the expected recovery of $8 million in business insurance proceeds relating to the outage of Clover Bar Energy Centre Unit 2 from March 8 until September 22 was recorded in the results for Alberta commercial plants and portfolio optimization. CPILP's EBITDA included asset impairment charges. Corporate EBITDA included $7 million for the recognition of the obligation to EPCOR for operations and maintenance costs for the Rossdale plant and assets over the ten-year period ending in 2019, and a write down of the fair value increments related to the asset impairment charges of CPILP's Ontario plants. Income taxes reflected the recognition of a future income tax liability relating to the investment in CPILP, as a result of the strategic alternatives review.

In the second quarter of 2010 the EBITDA for the Alberta contracted plants reflected availability penalties related to the 21-day scheduled outage at Genesee 2.

In the fourth quarter of 2009, the planned outage at Genesee 1 resulted in availability penalty payments. An income tax recovery that was recognized in the third quarter was reclassified in the fourth quarter and included in the acquisition of assets from EPCOR since it related to periods prior to July 1, 2009.

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.

(unaudited)	Three months ended								
	June 30, 2011	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009	Sept 30, 2009	June 30, 2009
Share price ($/ common share)									
High	28.00	26.44	24.84	24.20	23.39	23.00	21.78	22.39	23.00
Low	24.90	22.80	23.25	21.75	21.76	20.97	18.95	19.50	22.00
Close	25.00	25.92	23.65	24.10	22.14	22.50	21.37	19.75	22.35
Volume traded (millions)	9.5	8.9	3.4	2.4	4.4	7.6	6.5	12.1	5.8

As at July 25, 2011, the Company had 49.645 million common shares outstanding, 47.416 million special voting shares outstanding, 5 million Cumulative Rate Reset Preference Shares, Series 1 outstanding and one special limited voting share outstanding. The weighted average number of common shares outstanding on a diluted basis was 40.412 million for the quarter ended June 30, 2011. All of the outstanding special voting shares and the outstanding special limited voting share are held indirectly by EPCOR.

As at July 25, 2011, CPLP had 21.750 million general partnership units outstanding, 27.724 million common limited partnership units outstanding and 47.416 million exchangeable limited partnership units outstanding, which are exchangeable for 47.416 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 limited partnership units are held indirectly by EPCOR.

As at July 25, 2011, CPILP had 56.598 million limited partnership units outstanding and 16.514 million of such units, representing 29.2% of the outstanding limited partnership units, were held by CPI Investments Inc. EPCOR held 51 Class A Shares of CPI Investments Inc. representing 51% of the votes and CPLP held 49 Class B Shares of CPI Investments Inc. representing 49% of the votes. CPLP had an effective 100% economic interest in CPI Investments Inc.

Additional Information

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

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2011	Three months ended June 30, 2010 (note 13)	Six months ended June 30, 2011	Six months ended June 30, 2010 (note 13)
Revenues	$ 455	$ 301	$ 895	$ 785
Other income	17	12	35	29
Energy purchases and fuel	(255)	(196)	(546)	(480)
Gross income	217	117	384	334
Other raw materials and operating charges	(37)	(22)	(66)	(41)
Staff costs and employee benefits expense	(42)	(47)	(81)	(88)
Depreciation and amortization	(64)	(62)	(122)	(119)
Impairments (note 6)	(43)	-	(43)	-
Other administrative expenses	(20)	(9)	(30)	(19)
Property taxes	(6)	(4)	(11)	(9)
Foreign exchange (losses) gains	(4)	2	(6)	1
Operating income (loss)	1	(25)	25	59
Gain on sale of power syndicate agreement	-	-	-	28
Finance expense	(35)	(20)	(44)	(39)
Income (loss) before tax	(34)	(45)	(19)	48
Income tax recovery (note 3)	12	11	11	10
Net income (loss)	$ (22)	$ (34)	$ (8)	$ 58
Attributable to:				
Non-controlling interests	$ 3	$ (26)	$ 14	$ 54
Shareholders of the Company	$ (25)	$ (8)	$ (22)	$ 4

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

Basic (note 7)	$ (0.67)	$ (0.37)	$ (0.69)	$ 0.18
Diluted (note 7)	$ (0.67)	$ (0.37)	$ (0.69)	$ 0.18

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

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

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Net income (loss)	$ (22)	$ (34)	$ (8)	$ 58
Other comprehensive income (loss):				
Available-for-sale assets:				
Unrealized gains on available-for-sale financial assets[1]	1	-	1	2
Cash flow hedges:				
Unrealized losses on derivative instruments[2]	(23)	(1)	(76)	(18)
Reclassification of (gains) losses on derivative instruments to income for the period[3]	19	(17)	16	(11)
Reclassification of ineffective portion to income for the period[4]	1	2	2	1
Net investment in foreign subsidiaries:				
Unrealized gain (loss)[5]	4	27	(8)	8
Other comprehensive income (loss), net of tax	2	11	(65)	(18)
Total comprehensive income (loss)	$ (20)	$ (23)	$ (73)	$ 40
Attributable to:				
Non-controlling interests	$ 2	$ (13)	$ (29)	$ 38
Shareholders of the Company	$ (22)	$ (10)	$ (44)	$ 2

[1] For the three and six months ended June 30, 2011, net of income tax expenses of nil. For the three and six months ended June 30, 2010, net of income tax expenses of nil and $1 respectively.

[2] For the three and six months ended June 30, 2011, net of income tax recoveries of $4 and $10 respectively. For the three and six months ended June 30, 2010, net of income tax recoveries of nil and $8 respectively.

[3] For the three and six months ended June 30, 2011, net of reclassification of income tax recoveries $2. For the three and six months ended June 30, 2010, net of reclassification of income tax expenses of $2 and $1 respectively.

[4] For the three and six months ended June 30, 2011, net of reclassification of income tax expense of nil. For the three and six months ended June 30, 2010, net of reclassification of income tax expenses of nil.

[5] For the three and six months ended June 30, 2011, net of income tax expenses of nil and $1 respectively. For the three and six months ended June 30, 2010, net of income tax recoveries of $2 and nil 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)

	June 30, 2011	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 41	$ 56
Trade and other receivables	218	286
Inventories	56	60
Derivative financial instruments assets (note 8)	65	152
Assets classified as held for sale (note 6)	1,437	-
	1,817	554
Non-current assets:		
Other assets	20	19
Derivative financial instruments assets (note 8)	24	76
Finance lease receivables	60	85
Other financial assets	41	89
Deferred tax assets	15	40
Intangible assets (note 5)	267	651
Property, plant and equipment	3,619	3,678
Goodwill	51	104
Total assets	$ 5,914	$ 5,296
Liabilities and Equity		
Current liabilities:		
Trade and other payables	$ 220	$ 282
Derivative financial instruments liabilities (note 8)	95	125
Loans and borrowings (note 9)	201	235
Deferred revenue and other liabilities	4	10
Provisions	22	20
Liabilities classified as held for sale (note 6)	886	-
	1,428	672
Non-current liabilities:		
Derivative financial instruments liabilities (note 8)	22	89
Loans and borrowings (note 9)	1,533	1,634
Deferred revenue and other liabilities	60	61
Deferred tax liabilities	34	73
Provisions	153	155
	1,802	2,012
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 10)	1,048	820
Retained earnings (deficit)	(34)	8
Other reserves	(17)	5
Retained earnings (deficit) and other reserves	(51)	13
	997	833
Non-controlling interests	1,687	1,779
Total equity	2,684	2,612
Subsequent event (note 12)		
Total liabilities and equity	$ 5,914	$ 5,296

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 (note 10)	Cash flow hedges[1]	Cumulative translation account[1]	Available-for-sale financial assets[1]	Defined benefit plan actuarial gains and 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	$ 5	$ (5)	$ 1	$ (2)	$ 6	$ 8	$ 833	$ 1,779	$ 2,612
Net income (loss)	-	-	-	-	-	-	(22)	(22)	14	(8)
Other comprehensive income (loss):										
Net change in fair value of available-for-sale financial assets	-	-	-	1	-	-	-	1	-	1
Cash flow derivative hedge losses	-	(86)	-	-	-	-	-	(86)	-	(86)
Reclassification of losses to income	-	18	-	-	-	-	-	18	-	18
Reclassification of ineffective portion to income	-	2	-	-	-	-	-	2	-	2
Unrealized loss on foreign currency translation	-	-	(7)	-	-	-	-	(7)	-	(7)
Tax on items recognized directly in equity	-	8	(1)	-	-	-	-	7	-	7
Attributed to non-controlling interests	-	35	9	(1)	-	-	-	43	(43)	-
Other comprehensive loss	$ -	$ (23)	$ 1	$ -	$ -	$ -	$ -	$ (22)	$ (43)	$ (65)
Total comprehensive loss	-	(23)	1	-	-	-	(22)	(44)	(29)	(73)
Issue of share capital	235	-	-	-	-	-	8	243	(13)	230
Transaction costs	(9)	-	-	-	-	-	-	(9)	-	(9)
Deferred taxes	2	-	-	-	-	-	-	2	-	2
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	(65)	(65)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	-	8	8
Issue of partnership units	-	-	-	-	-	-	-	-	14	14
Common share dividends	-	-	-	-	-	-	(25)	(25)	-	(25)
Preferred share dividends	-	-	-	-	-	-	(3)	(3)	-	(3)
Preferred share dividends paid by subsidiary	-	-	-	-	-	-	-	-	(7)	(7)
Equity as at June 30, 2011	$ 1,048	$ (18)	$ (4)	$ 1	$ (2)	$ 6	$ (34)	$ 997	$ 1,687	$ 2,684

[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 (note 10)	Cash flow hedges[1]	Cumulative translation account[1]	Available-for-sale financial assets[1]	Employee benefits reserve	Retained earnings (deficit)	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2010	$ 477	$ 7	$ -	$ -	$ 2	$ 7	$ 493	$ 2,123	$ 2,616
Net income	-	-	-	-	-	4	4	54	58
Other comprehensive income (loss):									
Net change in fair value of available-for-sale financial assets	-	-	-	3	-	-	3	-	3
Cash flow derivative hedge losses	-	(26)	-	-	-	-	(26)	-	(26)
Reclassification of gains to income	-	(12)	-	-	-	-	(12)	-	(12)
Reclassification of ineffective portion to income	-	1	-	-	-	-	1	-	1
Unrealized gain on foreign currency translation	-	-	8	-	-	-	8	-	8
Tax on items recognized directly in equity	-	9	-	(1)	-	-	8	-	8
Attributed to non-controlling interests	-	25	(7)	(2)	-	-	16	(16)	-
Other comprehensive income (loss)	$ -	$ (3)	$ 1	$ -	$ -	$ -	$ (2)	$ (16)	$ (18)
Total comprehensive income (loss)	-	(3)	1	-	-	4	2	38	40
Distributions to non-controlling interests	-	-	-	-	-	-	-	(69)	(69)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	3	3
Issue of partnership units	-	-	-	-	-	-	-	13	13
Common share dividends	-	-	-	-	-	(14)	(14)	-	(14)
Preferred share dividends paid by subsidiary	-	-	-	-	-	-	-	(7)	(7)
Share-based compensation	-	-	-	-	2	-	2	-	2
Equity as at June 30, 2010	$ 477	$ 4	$ 1	$ -	$ 4	$ (3)	$ 483	$ 2,101	$ 2,584

[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)

	Six months ended June 30, 2011	2010
Cash flows from operating activities:		
Net income (loss)	$ (8)	$ 58
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	122	119
Gain on sale of power syndicate agreement	-	(28)
Impairments (note 6)	43	-
Finance expense	44	39
Fair value changes on derivative instruments	24	50
Unrealized foreign exchange losses	5	-
Income tax recovery	(11)	(10)
Other items	6	(22)
Interest paid[1]	(31)	(28)
Income taxes paid	(12)	(3)
Income taxes recovered	-	10
	182	185
Change in non-cash operating working capital	(14)	(26)
Net cash flows from operating activities	168	159
Cash flows from investing activities:		
Business acquisitions, net of acquired cash (note 4)	(643)	-
Payments to acquire property, plant and equipment and other assets	(209)	(183)
Proceeds on sale of power syndicate agreement	-	64
Other cash flows from investing activities	24	9
Net cash flows used in investing activities	(828)	(110)
Cash flows from financing activities:		
Proceeds from issue of loans and borrowings	599	335
Repayment of loans and borrowings	(51)	(246)
Proceeds from issue of common shares	235	-
Share issue costs	(9)	-
Issue costs on loans and borrowings	(3)	(2)
Distributions paid to non-controlling interests	(51)	(56)
Common share dividends paid (note 10)	(22)	(14)
Preferred share dividends paid (note 10)	(3)	-
Preferred share dividends paid by subsidiary	(7)	(7)
Financing interest paid[1]	(24)	(22)
Net cash flows from (used in) financing activities	664	(12)
Foreign exchange losses on cash held in a foreign currency	(6)	-
Net (decrease) increase in cash and cash equivalents	(2)	37
Cash and cash equivalents at beginning of period	56	52
Cash and cash equivalents at end of period	$ 54	$ 89

[1] Total interest paid.

See accompanying notes to the condensed interim consolidated financial statements

1. Reporting entity:

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

The registered and head office of the Company is located at 10088-102 Avenue, Edmonton, Alberta, Canada, T5J 2Z1. 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 and conversion to IFRS:

These condensed interim consolidated financial statements have been prepared by Management in accordance with International Accounting Standards (IAS) 34, Interim Financial Reporting. These condensed interim consolidated financial statements reflect part of the period covered by the Company’s first International Financial Reporting Standards (IFRS) annual financial statements and IFRS 1 First time Adoption of International Financial Reporting Standards has been applied. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements.

These condensed interim consolidated financial statements should be read in conjunction with the Company’s 2010 annual financial statements prepared in accordance with previous Canadian generally accepted accounting principles (GAAP) as well as the Company’s March 31, 2011 condensed interim consolidated financial statements prepared in accordance with IFRS. The Company’s March 31, 2011 condensed interim consolidated financial statements include certain disclosures not repeated in the June 30, 2011 condensed interim consolidated financial statements, including disclosure of IFRS 1 elections made by the Company, the Company’s significant accounting policies in accordance with IFRS, the Company’s use of judgments and estimates, reconciliations of equity and total comprehensive income reported under previous Canadian GAAP to those reported under IFRS as at January 1, 2010, as at and for the three months ended March 31, 2010, and as at and for the year ended December 31, 2010, and certain other supplementary annual disclosures for the year ended December 31, 2010.

An explanation of how the transition to IFRS has affected the financial position, financial performance and cash flows of the Company as at and for the three and six months ended June 30, 2010 is provided in note 13. This note includes reconciliations of equity and total comprehensive income reported under previous Canadian GAAP to those reported under IFRS as at and for the three and six months ended June 30, 2010.

These condensed interim consolidated financial statements have been prepared under the historical cost basis, except for the revaluation of the Company’s derivative instruments, cash, equity investments and cash-settled share based payments, which are stated at fair value. In addition, the Company’s defined benefit pension assets are recognized at fair value.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on July 27, 2011.

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

2. Basis of presentation and conversion to IFRS, continued:

Future accounting standards

A number of new standards, and amendments to standards and interpretations, are not yet effective for the quarter ended June 30, 2011 and have not been applied in preparing these condensed interim consolidated financial statements. The following standards and interpretations have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committees with effective dates relating to the annual periods starting on or after the effective dates as follows:

International Accounting Standards (IAS/IFRS)	Effective Date
IAS 12 - Income Taxes	January 1, 2012
IAS 1 – Presentation of Financial Statements	July 1, 2012
IFRS 9 – Financial Instruments	January 1, 2013
IFRS 10 – Consolidated Financial Statements	January 1, 2013
IFRS 11 – Joint Arrangements	January 1, 2013
IFRS 12 – Disclosures of Interests in Other Entities	January 1, 2013
IFRS 13 – Fair Value Measurement	January 1, 2013
IAS 19 – Employee Benefits	January 1, 2013

The amendments to IAS 12 relate to the measurement of deferred taxes for investment property, property, plant and equipment and intangible assets carried at fair value.

The amendments to IAS 1 provide improvements to the presentation of components of other comprehensive income. It requires entities to group items within other comprehensive income that may be reclassified to profit or loss.

IFRS 9 applies to the classification and measurement of financial assets and financial liabilities. It is the first of three phases of a project to develop standards to replace IAS 39 - Financial Instruments and was initiated in response to the crisis in financial markets.

IFRS 10 replaces IAS 27 Consolidated and Separate Financial Statements and SIC – 12 Consolidation – Special Purpose Entities. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. It provides a single consolidation model that identifies control as the basis for consolidation for all types of entities. IFRS 12 provides comprehensive disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and special purpose vehicles.

IFRS 11 supersedes IAS 31 – Interests in Joint Ventures and SIC 13 – Jointly Controlled Entities – Non-Monetary Contributions by Venturers. The standard requires a single method to account for interests in jointly controlled entities. All joint ventures are required to be recognized as an investment and be accounted for on an equity basis.

IFRS 13 defines fair value, sets out in a single IFRS a framework for measuring fair value and requires disclosures about fair value measurements. IFRS 13 applies when other IFRSs require or permit fair value measurements. It does not introduce any new requirements to measure an asset or a liability at fair value, change what is measured at fair value in IFRSs or address how to present changes in fair value.

The amendments to IAS 19 relate to the recognition and disclosure requirements for defined benefit plans and result in the following key changes: (a) to eliminate the corridor method that defers the recognition of gains and losses, (b) to streamline the presentation of changes in assets and liabilities arising from defined benefit plans, and (c) to enhance the disclosure requirements for defined benefit plans.

The extent of the impact of adoption of these standards and interpretations on the consolidated financial statements of the Company has not been determined.

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

3. Income tax:

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Current income tax				
Current income tax	$ (3)	$ -	$ 1	$ 14
Deferred income tax				
Adjustments relating to previously unrecognized temporary difference	(7)	-	(7)	-
Relating to origination and reversal of temporary differences	(4)	(16)	(6)	(23)
Relating to changes in tax rates / new taxes	-	3	(2)	(4)
Relating to write-downs of deferred tax asset	2	2	3	3
Income tax recovery	$ (12)	$ (11)	$ (11)	$ (10)

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Income (loss) before tax	$ (34)	$ (45)	$ (19)	$ 48
Income tax at the statutory rates of 26.5% and 28.0%, respectively	(9)	(13)	(5)	13
Increase (decrease) resulting from				
Taxable income attributable to non-controlling interests	1	5	(1)	(15)
Amounts previously not recognized on investments in subsidiaries	(7)	-	(7)	-
Change in valuation allowance	2	2	3	3
Non-taxable amounts	-	(5)	(1)	(6)
Adjustment for enacted changes in income tax laws and rates	-	3	(2)	(4)
Other	1	(3)	2	(1)
Income tax recovery	$ (12)	$ (11)	$ (11)	$ (10)

4. Acquisitions of subsidiaries:

On April 28, 2011, a subsidiary of the Company acquired one hundred per cent of the equity interests in Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport Energy), from a third party. Bridgeport Energy is a natural gas-fired combined cycle power generation facility located in Bridgeport, Connecticut, with a nominal capacity of 520 MW. The total fair value of consideration paid was $344 million (US$362 million) in cash, which consists of the acquisition's $338 million (US$355 million) base purchase price, plus normal working capital adjustments of $6 million (US$7 million), and was allocated to the assets acquired and liabilities assumed based on their estimated fair values as described below.

On April 29, 2011, a subsidiary of the Company acquired one hundred per cent of the equity interests in Tiverton Power Inc. and Rumford Power Inc. (Tiverton and Rumford), which own generating facilities located in Tiverton, Rhode Island and Rumford, Maine respectively, from a third party. Both plants are natural gas-fired combined cycle power generation facilities serving the New England region in the U.S. Northeast, and have a maximum combined capacity of 549 MW. The total fair value of consideration paid was the base purchase price of $299 million (US$315 million) in cash, and was allocated to the assets acquired and liabilities assumed based on their estimated fair values as described below.

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

4. Acquisitions of subsidiaries, continued:

	Bridgeport Energy	Tiverton and Rumford
Trade and other receivables	$ 8	$ 11
Inventories	4	4
Intangible assets	7	3
Property, plant and equipment	337	292
Goodwill	24	3
Trade and other payables	(14)	(12)
Derivative financial instruments liabilities - current	-	(2)
Derivative financial instruments liabilities - non-current	(8)	-
Deferred tax liabilities	(14)	-
Fair value of net assets acquired	$ 344	$ 299

The above acquisitions support the Company's growth strategy and are consistent with the Company's technology and operating focus.

The $8 million and $11 million allocated to trade and other receivables for the Bridgeport Energy and Tiverton and Rumford acquisitions above represent both the estimated fair value and the gross contractual amounts receivable. As at April 28, 2011 and April 29, 2011 for each acquisition respectively, the Company estimated that all of the contractual cash flows pertaining to the acquired trade and other receivables were collectible.

The goodwill recognized on the above acquisitions is not deductible for tax purposes and is attributable to:

- the potential to build an additional peaking facility near the existing Bridgeport Energy facility which would take advantage of higher on-peak pricing and higher load requirements in the facility's operating region; and
- the potential for synergies, within the New England area, in operating costs, asset and energy management and energy marketing due to the two acquisitions being located in the same area.

The results of operations of Bridgeport Energy and Tiverton and Rumford are included in the Company's consolidated statements of income and statements of changes in equity from the dates of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statement of financial position. Since the acquisition dates of April 28, 2011 and April 29, 2011 respectively, $37 million of revenues and $5 million of net income from Bridgeport Energy are included in the consolidated statements of income and $19 million of revenues and $1 million of net income from Tiverton and Rumford are included in the consolidated statements of income for the three and six months ending June 30, 2011. Had the acquisitions occurred at January 1, 2011, the combined entity of the Company, Bridgeport Energy and Tiverton and Rumford would have had a total of $474 million of revenues and $28 million of net loss for the three months ended June 30, 2011 and $1 billion of revenues and $14 million of net loss for the six months ended June 30, 2011.

In conjunction with the above acquisitions, the Company incurred $2 million in acquisition costs which have been recorded on the Company's statement of income as other administrative expenses for the three and six months ended June 30, 2011.

As of the release date of these financial statements, information required to finalize the working capital adjustments associated with the acquisitions is outstanding and as a result the purchase prices and the allocations to the acquired assets and assumed liabilities above are preliminary and are subject to change. The Company expects to finalize these purchase price allocations in the third quarter of 2011.

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

5. Intangible assets:

On May 25, 2011, a subsidiary of the Company, CPLP, acquired one hundred per cent of Halkirk I Wind Project LP and Halkirk I Wind Project Ltd (Halkirk Wind Project) and as a result the intangible assets owned by those entities. In connection with the acquisition, Capital Power will build, own and operate the 150 MW Halkirk Wind Project located in east central Alberta for an estimated total project cost of $357 million, of which $51 million has been incurred as at June 30, 2011. The total $51 million incurred to date includes the total fair value of consideration paid for the intangible assets of $33 million in cash. The acquired intangible assets include various permits required to construct the Halkirk Wind Project, land lease rights and the value of a 20-year agreement whereby the Company will sell Renewable Energy Credits (RECs) produced by the Halkirk Wind Project to a third party. The agreement to sell RECs will be amortized over its 20 year useful life while the other intangible assets will be amortized over the life of the Halkirk Wind Project plant assets. Amortization for all intangible assets associated with the Halkirk Wind Project will begin upon commencement of commercial operations of the Halkirk Wind Project, which is expected in the last half of 2012.

6. Assets classified as held for sale:

On June 20, 2011, the Company announced that its indirect subsidiary, Capital Power Income L.P. (CPILP), entered into an agreement with a third party, Atlantic Power Corporation (Atlantic), pursuant to which Atlantic will acquire directly and indirectly, all of the outstanding limited partnership units of CPILP, including Capital Power's approximate 29.2% ownership interest in CPILP. In connection with the agreement, Capital Power will acquire CPILP's Roxboro and Southport plants in North Carolina (North Carolina Assets) for $121 million in cash. Atlantic will acquire CPILP and its remaining eighteen facilities outside of North Carolina. Upon closing of the transaction, which is expected to occur in the fourth quarter of 2011, Capital Power will receive $320 million in combined consideration for its ownership interest in CPILP. The consideration will include stock in Atlantic and cash which will be used partly to fund the acquisition of the North Carolina Assets described above. In connection with this transaction, the management contracts between Capital Power and CPILP will be terminated for consideration of $10 million.

At June 30, 2011, the disposal group consisted of assets and liabilities as follows:

	June 30, 2011
Assets classified as held for sale	
Cash and cash equivalents	$ 13
Trade and other receivables	54
Inventories	11
Derivative financial instruments assets – current and non-current	46
Finance lease receivables	22
Other financial assets	47
Deferred tax assets	6
Intangible assets	353
Property, plant and equipment	806
Goodwill	79
	$ 1,437
Liabilities classified as held for sale	
Trade and other payables	$ (47)
Derivative financial instruments liabilities – current and non-current	(102)
Loans and borrowings – current and non-current	(667)
Deferred revenue and other liabilities – current and non-current	(13)
Deferred tax liabilities	(17)
Provisions – non-current	(40)
	$ (886)

6. Assets classified as held for sale, continued:

Immediately before the initial classification of the above assets to assets held for sale, the Company determined, based on the negotiated consideration to be received as compared to the existing carrying amounts for the assets to be reclassified to assets held for sale, that it was necessary to test the management contracts for additional impairments and to test certain other cash generating units (CGUs), consisting of various CPILP plants, within the disposal group for potential reversals of impairments. As a result the Company recorded additional impairments of $43 million on the management contracts immediately prior to reclassification to assets held for sale in the period, consisting of $7 million within the U.S. geographic area and $36 million within the Canadian geographic area. The Company did not record reversals of any previous impairments taken on its CGUs.

For purposes of calculating the above impairments and testing for reversals of impairments, the Company used the fair value less costs to sell of the CGUs within the disposal group as the recoverable amount of the assets. The fair value less costs to sell was established as the negotiated consideration in the agreements described above, less the Company's estimate of the directly attributable incremental costs related to the disposal.

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

As at June 30, 2011, accumulated other comprehensive loss, included within other reserves within the consolidated statement of financial position, included accumulated losses of $8 million relating to the Company's investment in CPILP. Of the $8 million relating to CPILP, $4 million relates to foreign currency translation losses previously recognized directly in accumulated other comprehensive loss and will be reclassified to net income (loss) upon close of the disposal transactions.

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

7. Earnings (loss) per share:

Basic earnings (loss) per share

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

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Income (loss) for the period attributable to shareholders of the Company	$ (25)	$ (8)	$ (22)	$ 4
Preferred share dividends of the Company [1]	(2)	-	(3)	-
Earnings (loss) used in the calculation of basic earnings (loss) per share	$ (27)	$ (8)	$ (25)	$ 4

[1] Includes preferred share dividends in respect of the current periods only.

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Weighted average number of common shares used in the calculation of basic earnings per share	40,419,750	21,751,512	36,392,096	21,750,760

Diluted earnings (loss) per share

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

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Earnings (loss) used in the calculation of basic earnings (loss) per share	$ (27)	$ (8)	$ (25)	$ 4
Effect of exchangeable limited partnership units issued to EPCOR for common shares [1]	-	-	-	-
Earnings (loss) used in the calculation of diluted earnings (loss) per share	$ (27)	$ (8)	$ (25)	$ 4

[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 three and six months ended June 30, 2011,and for the three and six months ended June 30, 2010 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.

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

7. Earnings (loss) per share, continued:

Diluted earnings (loss) per share, continued

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

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
Weighted average number of common shares used in the calculation of basic earnings (loss) per share	40,419,750	21,751,512	36,392,096	21,750,760
Effect of dilutive share purchase options[1]	-	-	-	-
Effect of exchangeable limited partnership units issued to EPCOR for common shares	-	-	-	-
Weighted average number of common shares used in the calculation of diluted earnings (loss) per share	40,419,750	21,751,512	36,392,096	21,750,760

[1] For the three and six months ended June 30, 2011, the average market price of the Company's common shares exceeded the exercise price of certain of the granted share purchase options. Since the Company recorded a loss for the three and six months ended June 30, 2011, the assumed exercise of the stock options increased the loss per share and as such did not have a dilutive effect on earnings (loss) per share. For the three and six months ended June 30, 2010, the average market price of the Company's common shares was below the exercise price of all granted share purchase options and as a result none of the share purchase options had a dilutive effect on earnings (loss) per share.

8. Derivative financial instruments and hedge accounting:

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

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

	June 30, 2011				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 2	$ 63	$ -	$ -	$ 65
Non-current	9	15	-	-	24
Derivative instruments liabilities:					
Current	(33)	(61)	(1)	-	(95)
Non-current	(8)	(14)	-	-	(22)
Net fair value	$ (30)	$ 3	$ (1)	$ -	$ (28)
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(12)			
Gigajoules of natural gas (millions)	-	-			
Foreign currency (U.S. dollars)			$ 147		
Interest rate swaps				$ -	
Range of contract terms in years	0.1 to 5.5	0.1 to 6.5	0.1 to 0.5		

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

8. Derivative financial instruments and hedge accounting, continued:

	December 31, 2010				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 28	$ 113	$ 11	$ -	$ 152
Non-current	16	30	30	-	76
Derivative instruments liabilities:					
Current	(24)	(92)	(3)	(6)	(125)
Non-current	(77)	(7)	(5)	-	(89)
Net fair value	$ (57)	$ 44	$ 33	$ (6)	$ 14
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(2)			
Gigajoules of natural gas (millions)	38	9			
Foreign currency (U.S. dollars)			$ (302)		
Interest rate swaps				$ 200	
Range of contract terms in years	0.1 to 6.0	0.1 to 7.0	0.1 to 5.5	0.2	

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices as appropriate, in the most advantageous active market for that instrument. The extent to which fair values of derivative instruments are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. When traded markets are not considered to be sufficiently active or do not exist, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates and maximize, when available, the use of external readily observable market data including future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rates, counterparty credit risk, the Company's own credit risk and volatility. When a valuation technique utilizes unobservable market data, no inception gains or losses are recognized, until market quotes or data becomes observable. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

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

	Three months ended June 30, 2011		Three months ended June 30, 2010	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (5)	$ (22)	$ (19)	$ 19
Energy non-hedges	-	-	(34)	10
Foreign exchange non-hedges	3	(2)	(18)	1
Interest rate non-hedges	(4)	(10)	(4)	-

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

8. Derivative financial instruments and hedge accounting, continued:

	Six months ended June 30, 2011		Six months ended June 30, 2010	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (66)	$ (18)	$ (36)	$ 12
Energy non-hedges	(33)	(10)	(34)	21
Foreign exchange non-hedges	4	2	(13)	4
Interest rate non-hedges	6	(12)	(4)	-

Realized gains and losses relate only to financial derivative instruments. Included in revenues for the three and six months ended June 30, 2011 were gains on financial derivative instruments held at fair value through income or loss of $3 million and losses of $81 million respectively (three and six months ended June 30, 2010 – losses of $130 million and $82 million respectively). Included in energy purchases and fuel for the three and six months ended June 30, 2011 were losses on financial instruments held at fair value through income or loss of $21 million and gains of $31 million respectively (three and six months ended June 30, 2010 – gains of $107 million and $71 million respectively). Included in foreign exchange (gains) losses for the three and six months ended June 30, 2011 were losses on financial instruments held at fair value through income or loss of $3 million and $5 million respectively (three and six months ended June 30, 2010 – gains of $1 million). Included in finance expense for the three and six months ended June 30, 2011 were losses on financial instruments held at fair value through income or loss of $14 million and $6 million respectively (three and six months ended June 30, 2010 – losses of $4 million). Gains and losses on non-financial derivative instrument settlements are recorded in energy purchases and fuel or revenues as appropriate.

If hedge accounting requirements are not met, unrealized and realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel as appropriate. If hedge accounting requirements are met, realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel, as appropriate, while unrealized gains and losses are recorded in other comprehensive income. Unrealized and realized gains and losses on financial foreign exchange derivatives are recorded in revenues or foreign exchange gains and losses while such gains and losses on financial interest rate derivatives are recorded in finance expense.

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 six months ended June 30, 2011, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized as losses in the statement of income were $1 million and $2 million respectively (three and six months ended June 30, 2010 – losses of $2 million and $1 million respectively).

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

	June 30, 2011
Within one year	$ (27)
Between 1 – 5 years	1
After more than 5 years	-
	$ (26)

The Company's cash flow hedges extend up to 2016.

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

9. Loans and borrowings:

On April 18, 2011, the Company's subsidiary, CPLP, issued $300 million of unsecured medium-term notes due in 2015 with interest payable semi-annually at 4.6% commencing on June 1, 2011.

On June 15, 2011, Capital Power U.S. Financing LP, an indirect subsidiary of the Company, closed a US$295 million private placement of unsecured senior notes. The unsecured senior notes consist of two notes with 10 and 15-year terms. The 10-year note of $222 million (US$230 million) is due in 2021 with a coupon rate of 5.21%. The 15-year note of $63 million (US$65 million) is due in 2026 with a coupon rate of 5.61%.

10. 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

	June 30, 2011		December 31, 2010	
	Issued	Outstanding	Issued	Outstanding
Common shares	40,445,213	$ 926	30,980,500	$ 698
Preferred shares, series 1	5,000,000	122	5,000,000	122
Special voting shares	47,416,000	-	47,416,000	-
Special limited voting share	1	-	1	-
		$ 1,048		$ 820

In the first quarter of 2011, the Company closed an offering to sell 9,315,000 common shares, to a syndicate of underwriters, at an offering price of $24.90 per common share for gross proceeds of $232 million, less issue costs of $9 million. Future income tax assets of $2 million related to the share issue costs are recorded in the common share balance. Subsequent to the issue of common shares by the Company, 9,315,000 additional limited partnership units of the Company's subsidiary, CPLP, were issued to another subsidiary of the Company and as a result, this transaction reduced EPCOR's ownership interest in CPLP to approximately 54.1% as at June 30, 2011 (December 31, 2010 - 60.5%).

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

10. Share capital, continued:

For the three and six months ended June 30, 2011, dividends of $13 million and $25 million respectively, or 31.5 cents per share, have been declared and dividends of $12 million and $22 million respectively have been paid by the Company to the common share holders (three and six months ended June 30, 2010 - $7 million and $14 million respectively, or 31.5 cents per share, declared and paid). During the three and six months ended June 30, 2011, dividends of $1 million (28.8 cents per share) and $3 million respectively have been declared and paid by the Company to preferred share holders. The dividends paid to preferred share holders in the first quarter of 2011, at 33.1 cents per share, related to the time period from when the initial share offering closed on December 16, 2010 to June 30, 2011 (three and six months ended June 30, 2010 – nil).

11. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation plants within Alberta, British Columbia, Ontario and in the U.S. in California, Colorado, Connecticut, Illinois, Maine, New Jersey, New York, North Carolina, Rhode Island and Washington, as this is how management assesses performance and determines resource allocations.

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

	Three months ended June 30, 2011				Three months ended June 30, 2010			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	$ 336	$ 136	$ -	$ 472	$ 243	$ 70	$ -	$ 313
Inter-area revenues and other income	-	-	-	-	3	1	(4)	-
Total revenues and other income	$ 336	$ 136	$ -	$ 472	$ 246	$ 71	$ (4)	$ 313

	Six months ended June 30, 2011				Six months ended June 30, 2010			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	$ 730	$ 200	$ -	$ 930	$ 662	$ 152	$ -	$ 814
Inter-area revenues and other income	1	1	(2)	-	7	5	(12)	-
Total revenues and other income	$ 731	$ 201	$ (2)	$ 930	$ 669	$ 157	$ (12)	$ 814

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

11. Segment information, continued:

	As at June 30, 2011				As at December 31, 2010			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Property, plant and equipment	$ 2,863	$ 756	$ -	$3,619	$3,174	$ 504	$ -	$3,678
Intangible assets	251	16	-	267	373	278	-	651
Goodwill	-	51	-	51	29	75	-	104
Other assets	20	-	-	20	19	-	-	19
Assets classified as held for sale	599	838	-	1,437	-	-	-	-
	$ 3,733	$1,661	$ -	$5,394	$3,595	$ 857	$ -	$4,452

12. Subsequent event:

Subsequent to the close of the second quarter, the Company closed an offering to sell an additional 9,200,000 common shares, to a syndicate of underwriters, at an offering price of $25.10 per common share for gross proceeds of $231 million, less issue costs of $9 million. Subsequent to the issue of common shares by the Company, 9,200,000 additional common limited partnership units of the Company's subsidiary, CPLP, were issued to another subsidiary of the Company and as a result this transaction reduced EPCOR's ownership interest in CPLP to approximately 48.9% effective for the third quarter of 2011 (June 30, 2011 – 54.1%, December 31, 2010 – 60.5%).

13. Transition to IFRS:

In accordance with the Canadian Institute of Chartered Accountants' adoption of IFRS, the Company has prepared financial statements which comply with IFRS applicable for periods beginning on or after January 1, 2010. This note explains the principal adjustments made by the Company in restating its previously published Canadian GAAP financial statements for the three and six months ended June 30, 2010.

The Company has applied optional exemptions and exceptions in its transition from Canadian GAAP to IFRS as described in its March 31, 2011 condensed interim consolidated financial statements.

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

13. Transition to IFRS, continued:

Reconciliation of equity

The reconciliation of equity reported under previous Canadian GAAP to equity under IFRS (First time adoption) as at June 30, 2010 (end of comparative period) was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation Reclassifications (e)	IFRS
Cash and cash equivalents	$ 89	$ -	$ -	$ -	$ -	$ -	$ 89
Trade and other receivables[1]	260	-	-	-	2	-	262
Inventories	73	5	-	-	-	-	78
Derivative financial instruments assets	128	-	-	-	-	-	128
Deferred tax assets	2	-	-	-	-	(2)	-
Total current assets	552	5	-	-	2	(2)	557
Other assets	108	-	-	-	-	(88)	20
Derivative financial instruments assets	93	-	-	-	-	-	93
Finance lease receivables	-	-	-	-	62	26	88
Other financial assets	-	-	-	-	-	62	62
Deferred tax assets	66	-	-	-	(25)	2	43
Intangible assets	691	-	(10)	-	-	-	681
Property, plant and equipment	3,364	25	(27)	52	35	31	3,480
Goodwill	141	-	(12)	-	-	-	129
Total non-current assets	4,463	25	(49)	52	72	33	4,596
Total assets	$ 5,015	$ 30	$ (49)	$ 52	$ 74	$ 31	$ 5,153

[1] Includes accounts receivable, income taxes recoverable and prepaid expenses.

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

13. Transition to IFRS, continued:

Reconciliation of equity, continued:

As at June 30, 2010:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation Reclassifications (e)	IFRS
Trade and other payables	$ 281	$ 3	$ -	$ -	$ -	$ (16)	$ 268
Derivative financial instruments liabilities	116	(1)	-	-	-	-	115
Loans and borrowings	35	-	-	-	-	-	35
Deferred revenue and other liabilities	9	-	-	-	-	-	9
Deferred tax liabilities	7	-	-	-	-	(7)	-
Provisions	-	(7)	-	-	-	16	9
Total current liabilities	448	(5)	-	-	-	(7)	436
Derivative financial instruments liabilities	100	(7)	-	-	-	-	93
Loans and borrowings	1,773	-	-	-	-	-	1,773
Deferred revenue and other liabilities	110	17	-	-	-	(72)	55
Deferred tax liabilities	79	-	-	-	(20)	7	66
Provisions	-	42	-	-	1	103	146
Total non-current liabilities	2,062	52	-	-	(19)	38	2,133
Share capital	477	-	-	-	-	-	477
Retained earnings	(2)	(3)	(5)	-	7	-	(3)
Other reserves	4	-	-	4	1	-	9
Equity attributable to shareholders of the Company	479	(3)	(5)	4	8	-	483
Non-controlling interests	2,026	(14)	(44)	48	85	-	2,101
Total equity	2,505	(17)	(49)	52	93	-	2,584
Total liabilities and equity	$ 5,015	$ 30	$ (49)	$ 52	$ 74	$ 31	$ 5,153

13. Transition to IFRS, continued:

Notes to the reconciliations

The tables above present the aggregate transitional adjustments from previous Canadian GAAP to IFRS. The following notes summarize the key differences noted on transition to IFRS.

(a) IAS 16 Property, Plant and Equipment & IAS 37 Provisions:

The contract between the Genesee mine operator and the Company requires the operating activities of the mine, including depreciation on the operator's share of the mine assets, to be fully funded by the Company, whereas the capital funding is shared by the two parties. As a result, certain costs that were previously capitalized would have been expensed under the requirements of IAS 16 and fully funded by Capital Power resulting in an increase to non-current deferred revenue and other liabilities of $11 million as at June 30, 2010. As a result of this change, trade and other payables of $2 million were recorded as at June 30, 2010. In addition, the Company recorded a transitional adjustment to align accounting policies between the Company and the Genesee mine operator resulting in an increase of $5 million in inventory, a decrease of $3 million to property, plant and equipment and an increase in non-current deferred revenue and other liabilities of $2 million as at June 30, 2010.

Under Canadian GAAP, the Joffre joint venture's overhaul costs for the Joffre cogeneration facility were expensed and the joint venture's recovery of overhaul costs from one of the joint venture partners was recognized as revenue in the period that the cost was incurred. Under the requirements of IAS 16, the overhaul costs are capitalized as a component of property, plant and equipment and recoveries are recognized in income over the period that the corresponding asset is depreciated. Therefore deferred revenue and other liabilities increased by $4 million as at June 30, 2010, on transition to IFRS for recoveries received by the joint venture of costs that had been expensed under Canadian GAAP and reclassified to property, plant and equipment under IFRS. As a result of this change, trade and other payables of $1 million were recorded as at June 30, 2010.

Under IFRS, accounting for the components of property, plant and equipment is required at a more detailed level than under Canadian GAAP. IAS 16 requires separate depreciation for those components with a distinct depreciation method or rate of deprecation. As a result of applying the componentization requirements of IAS 16 effective July 1, 2009, the net book value of property, plant and equipment decreased by $8 million, reflecting increased depreciation net of overhaul costs capitalized, as at June 30, 2010.

IAS 37 requires provisions to be measured at the best estimate of the expected expenditure using discount rates appropriate for each liability. Under Canadian GAAP the provision was measured at fair value. The provision is to be re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Company re-measured its decommissioning liabilities (asset retirement obligations) using revised cash flow estimates with respect to the Genesee Mine as well as for revised discount rates for all decommissioning liabilities. The re-measurement of the decommissioning liabilities resulted in a decrease of $8 million to the current provision and an increase of $33 million to the non-current provision as at June 30, 2010. The re-measurement of the decommissioning liability also resulted in an increase of $36 million to the associated property, plant and equipment as at June 30, 2010.

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(a) IAS 16 Property, Plant and Equipment & IAS 37 Provisions, continued:

Under IFRS, amounts provided for the unavoidable costs of the Company's Alberta retail and commercial natural gas contracts are recognized as provisions in the financial statements. Accordingly, the Company has reclassified $1 million from current derivative financial instruments liabilities to current provisions as at January 1, 2010. As well, related to these contracts, the Company recognized an additional $11 million in non-current provisions as at January 1, 2010 of which $7 million was reclassified from non-current derivative financial instruments liabilities as at January 1, 2010. As a result of changes in cash flow assumptions and discount rates, the non-current provision recorded at January 1, 2010 was decreased by $2 million as at June 30, 2010.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in a decrease of $3 million in the equity attributable to shareholders and a decrease of $14 million to non-controlling interests as at June 30, 2010.

(b) IAS 36 – Impairment of Assets:

IAS 36 requires that impairment testing be done on a CGU level, which is the smallest identifiable group of assets that generates cash inflows. For Capital Power, some CGUs consist of a single plant resulting in more CGUs subject to impairment testing under IFRS than under Canadian GAAP. In addition, any goodwill amounts must be allocated and included in the impairment test for each CGU. Accordingly, this change may result in more frequent write downs of goodwill under IFRS.

IAS 36 also requires a one-step approach to determine the recoverable amount of a CGU. Canadian GAAP's two-step approach required the application of discounted cash flow techniques to measure the impairment amount, but only after the use of undiscounted cash flow analysis indicated the existence of an impairment. The adoption of IAS 36 is expected to result in more frequent write downs since the carrying amount of assets which are supported by undiscounted cash flows may be determined to be impaired when the future cash flows are discounted in accordance with the IFRS requirements. Unlike Canadian GAAP, previous impairment losses may be reversed or reduced if the circumstances which lead to the impairment change, except for impairment losses attributed to goodwill.

In accordance with IAS 36, the Company reviewed the recoverable amount for its CGUs with allocated goodwill at both the date of transition to IFRS and as at December 31, 2010. The key assumptions used in those reviews are disclosed in note 14(d) of the March 31, 2011 condensed interim consolidated financial statements. For all other CGUs, management assessed whether there were any triggering events at the date of transition to IFRS, as at June 30, 2010 and as at December 31, 2010. Recoverable amounts were calculated on a fair value less cost to sell basis, using discounted cash flow models based on the Company's long-term planning model. As a result of the review of recoverable amounts it was determined that certain of the Company's CGUs were impaired.

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

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(b) IAS 36 – Impairment of Assets, continued:

The impacts of the impairments by CGU and by line item, excluding the impacts on depreciation and foreign currency translation, as at June 30, 2010 were:

	Goodwill	Intangible assets	Property, plant and equipment	Total
CPILP manager contracts	$ -	$ 7	$ -	$ 7
Calstock	9	1	8	18
Greeley	-	-	7	7
Moresby Lake	2	1	2	5
Naval Training Centre	1	1	-	2
Roxboro	-	-	11	11
	$ 12	$ 10	$ 28	$ 50

The impairments noted above for Greeley, Naval Training Centre, Roxboro and $2 million of the CPILP manager contract impairments are reported in the U.S. geographic area while the impairments for Calstock, Moresby Lake and $5 million of the CPILP manager contract impairments are reported in the Canadian geographic area.

As a result of the change in impairment testing under IFRS to a one-step discounted cash flow test, the Company has determined that the carrying amount of the CPILP manager contracts was in excess of the fair value less cost to sell for the contracts, resulting in the impairment noted above.

The impairment recorded for the Calstock facility at January 1, 2010 was a result of higher than expected wood waste costs due to declines in wood waste availability caused by weakness in the Ontario forestry sector. The impairments recorded for the Greeley and Roxboro facilities at January 1, 2010 were due to the impact of weakening economic conditions in their respective markets.

The total adjustments resulting from IAS 36, including resulting impacts on depreciation and foreign currency translation gains and losses, impact equity in proportion to the Company’s owners’ respective shares of the adjustments and accordingly resulted in a decrease of $5 million in the equity attributable to shareholders and a decrease of $44 million to non-controlling interests as at June 30, 2010.

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(c) IFRS 1 – First Time Adoption of IFRS:

IFRS 1 – First Time Adoption of IFRS provides an election to deem any cumulative translation differences to be zero on transition to IFRS. As a result of the Company taking the IFRS 1 election to adjust the balance of its cumulative translation account to nil at the date of transition, $4 million was reclassified within equity, between accumulated other comprehensive income and retained earnings at January 1, 2010.

IFRS 1 also provides an optional election on transition to IFRS which allows the use of fair value as deemed cost on items of property, plant and equipment. The Company has elected under IFRS 1 to fair value certain items of property, plant and equipment resulting in an increase to property, plant and equipment, net of resulting foreign exchange and depreciation changes, of $52 million as at June 30, 2010.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in an increase of $4 million in the equity attributable to shareholders and an increase of $48 million to non-controlling interests as at June 30, 2010.

(d) Other Impacts:

In accordance with IAS 17 – Leases, the Kingsbridge PPA was determined to be a finance lease. The transitional adjustment was a result of IAS 17 and Canadian GAAP having different qualitative guidelines in the determination of the classification of leases between operating and finance (or capital under Canadian GAAP). As a result, property, plant and equipment was decreased by $51 million, finance lease receivable was increased by $62 million, trade and other receivables was increased by $2 million and retained earnings was increased by $13 million as at June 30, 2010.

In accordance with IAS 31 – Interests in Joint Ventures, the Company has concluded that it controls the Genesee mine joint venture and as a result is required to consolidate this investment under IFRS. As a result, property plant and equipment was increased by $86 million as at June 30, 2010, with the full amount of the changes being attributed to non-controlling interests.

The Company has elected, under IFRS 1, to recognize all actuarial gains and losses in other comprehensive income. Under Canadian GAAP, the Company recognized actuarial gains and losses into income or loss using the corridor approach whereby amounts that exceeded the corridor were recognized into income or loss over the average remaining service period of the active employees. At the date of transition, all previously unrecognized cumulative actuarial gains and losses were recognized in retained earnings. As at June 30, 2010, the provision was increased and other comprehensive income was decreased by $1 million.

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(d) Other Impacts, continued:

Under IAS 39, hedge effectiveness testing must incorporate the entity's credit risk. The net impact of the IAS 39 changes was an increase to accumulated other comprehensive income of $1 million as at June 30, 2010, with a corresponding decrease to retained earnings.

The Company's share-based payments contain graded vesting provisions and as such, in accordance with IFRS 2 – Share-based payments, are treated as a series of individual awards with compensation measured and recognized separately for each tranche, within a grant, that has a different vesting date. Under GAAP, the Company treated each grant as a single award and used an average life to recognize the compensation for each grant on a straight-line basis. The net impact of the IFRS 2 change was an increase in the employee benefits reserve of $1 million as at June 30, 2010.

Other impacts also include the impact of tax on the IFRS adjustments recognized. To recognize the income tax impact of the IFRS transition adjustments, deferred tax assets were decreased by $25 million and deferred tax liabilities were decreased by $20 million as at June 30, 2010.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in an increase of $8 million in the equity attributable to shareholders and an increase of $85 million to non-controlling interests as at June 30, 2010.

(e) Presentation reclassifications:

IAS 1 – Presentation of Financial Statements, provides presentation requirements for the statement of financial position. Accordingly, the following items have been reclassified:

- Financial assets must be presented separately from other assets. Accordingly, $26 million was reclassified from other assets to finance lease receivables and $62 million was reclassified from other assets to other financial assets as at June 30, 2010.
- Provisions must be presented as a separate item on the statement of financial position. Accordingly, $16 million was reclassified from accounts payable to current provisions and $103 million was reclassified from other non-current liabilities to non-current provisions as at June 30, 2010.
- Deferred tax balances are to be classified as non-current. Therefore, as at June 30, 2010, the current deferred tax assets and liabilities of $2 million and $7 million respectively, were reclassified to non-current deferred tax assets and liabilities respectively.
- International Financial Reporting Interpretations Committee (IFRIC) 18 requires that contributions received with respect to the construction of property, plant and equipment and used to provide goods or services, be classified as deferred revenue. Accordingly, $31 million of contributions that were previously reported as reductions of property, plant and equipment were reclassified as increases in deferred revenue and other liabilities as at June 30, 2010.

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

13. Transition to IFRS, continued:

Reconciliation of total comprehensive income (loss)

The reconciliation of total comprehensive loss reported under previous Canadian GAAP for the three months ended June 30, 2010 to total comprehensive loss reported under IFRS was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (f)	IAS 36 Impact (g)	IFRS 1 elections (h)	Other impacts (i)	Presentation Reclassifications (j)	IFRS
Revenues	$ 302	$ -	$ -	$ -	$ (1)	$ -	$ 301
Other income	11	-	-	-	-	1	12
Energy purchases and fuel	(193)	(2)	-	-	(1)	-	(196)
Gross income	120	(2)	-	-	(2)	1	117
Operations, maintenance and direct administration	(61)	-	-	-	-	61	-
Indirect administration	(31)	-	-	-	-	31	-
Other raw materials and operating charges	-	15	-	-	-	(37)	(22)
Staff costs and employee benefits expense	-	-	-	-	(1)	(46)	(47)
Depreciation and amortization	(52)	(10)	-	(1)	(1)	2	(62)
Other administrative expenses	-	-	-	-	-	(9)	(9)
Property taxes	(4)	-	-	-	-	-	(4)
Foreign exchange gains	2	-	-	-	-	-	2
Operating loss	(26)	3	-	(1)	(4)	3	(25)
Finance expense	(19)	2	-	-	-	(3)	(20)
Loss before tax	(45)	5	-	(1)	(4)	-	(45)
Income tax recovery	7	-	-	-	4	-	11
Net loss	(38)	5	-	(1)	-	-	(34)
Other comprehensive income	11	-	(1)	4	(3)	-	11
Total comprehensive loss	(27)	5	(1)	3	(3)	-	(23)
Attributable to:							
Non-controlling interests	$ (17)	$ 5	$ (1)	$ 2	$ (2)	$ -	$ (13)
Shareholders of the Company	$ (10)	$ -	$ -	$ 1	$ (1)	$ -	$ (10)

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

13. Transition to IFRS, continued:

Reconciliation of total comprehensive income (loss), continued

The reconciliation of total comprehensive income reported under previous Canadian GAAP for the six months ended June 30, 2010 to total comprehensive income reported under IFRS was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (f)	IAS 36 Impact (g)	IFRS 1 elections (h)	Other impacts (i)	Presentation Reclassifications (j)	IFRS
Revenues	$ 787	$ -	$ -	$ -	$ (2)	$ -	$ 785
Other income	25	1	-	-	1	2	29
Energy purchases and fuel	(476)	(4)	-	-	-	-	(480)
Gross income	336	(3)	-	-	(1)	2	334
Operations, maintenance and direct administration	(105)	-	-	-	-	105	-
Indirect administration	(57)	-	-	-	-	57	-
Other raw materials and operating charges	-	15	-	-	-	(56)	(41)
Staff costs and employee benefits expense	-	-	-	-	(1)	(87)	(88)
Depreciation and amortization	(98)	(19)	1	(2)	(3)	2	(119)
Other administrative expenses	-	-	-	-	-	(19)	(19)
Property taxes	(9)	-	-	-	-	-	(9)
Foreign exchange gains	1	-	-	-	-	-	1
Operating income	68	(7)	1	(2)	(5)	4	59
Gains on acquisitions and disposals	28	-	-	-	-	-	28
Finance expense	(37)	2	-	-	-	(4)	(39)
Income before tax	59	(5)	1	(2)	(5)	-	48
Income tax recovery	7	-	-	-	3	-	10
Net income	66	(5)	1	(2)	(2)	-	58
Other comprehensive loss	(20)	-	-	1	1	-	(18)
Total comprehensive income	46	(5)	1	(1)	(1)	-	40
Attributable to:							
Non-controlling interests	43	(3)	-	(1)	(1)	-	38
Shareholders of the Company	$ 3	$ (2)	$ 1	$ -	$ -	$ -	$ 2

13. Transition to IFRS, continued:

Notes to the reconciliations

The tables above present the aggregate transitional adjustments from previous Canadian GAAP to IFRS. The following notes summarize the key differences noted on transition to IFRS.

(f) IAS 16 Property, Plant and Equipment & IAS 37 Provisions:

As noted in the reconciliation of equity on transition, as a result of the Company re-measuring its commercial natural gas contracts, other income increased by nil and $1 million for the three and six months ended June 30, 2010 respectively.

Energy purchases and fuel costs increased by $2 million and $4 million for the three and six months ended June 30, 2010 respectively as a result of the increase to coal costs due to costs related to the Genesee mine that were previously capitalized under GAAP which are expensed under IFRS.

Other raw materials and operating charges used decreased by $15 million for the three and six months ended June 30, 2010 as a result of capitalizing the overhaul costs which had previously been expensed under GAAP.

The impacts to depreciation and amortization as a result of implementing IAS 16 were increases of $8 million and $16 million for the three and six months ended June 30, 2010 respectively.

Depreciation and amortization expense was increased by $2 million and $3 million for the three and six months ended June 30, 2010 respectively as a result of implementing IAS 37 which resulted in an increase in the value of decommissioning assets on transition.

Finance costs decreased by $2 million for the three and six months ended June 30, 2010 as a result of accretion expense being lower as a result of implementing IAS 37.

(g) IAS 36 Impairments:

The Company recognized certain impairments against property, plant and equipment, intangible assets and goodwill on transition to IFRS. As a result of these impairments, the Company's depreciation and amortization expense decreased by nil and $1 million for the three and six months ended June 30, 2010 respectively.

(h) IFRS 1 First Time Adoption of IFRS:

As noted in the reconciliation of equity on transition, the Company elected to use the fair value at transition date as deemed cost for certain plants. As a result of this election, the Company's depreciation and amortization expense has increased by $1 million and $2 million for the three and six months ended June 30, 2010 respectively.

(i) Other Impacts:

As noted in the reconciliation of equity on transition, one of the Company's power purchase arrangements was determined to be a finance lease which resulted in a reduction to property, plant and equipment and an increase to finance lease receivable. As such, there were reductions to electricity sales revenues of $1 million and $2 million for the three and six months ended June 30, 2010 respectively, increases to other income of nil and $1 million for the three and six months ended June 30, 2010 respectively and reductions to depreciation and amortization of nil and $1 million for the three and six months ended June 30, 2010 respectively.

As noted in the reconciliation of equity on transition, the Company has concluded that it controls the Genesee mine joint venture and as a result is required to consolidate this investment under IFRS. As a result, depreciation and amortization increased by $1 million and $4 million for the three and six months ended June 30, 2010 respectively, with the full amount of the changes being attributed to non-controlling interests.

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(i) Other impacts, continued:

The impacts of incorporating the Company's credit risk in the hedge effectiveness testing under IAS 39 were increases to energy purchases and fuel of $1 million and nil for the three and six months ended June 30, 2010 with offsetting charges to other comprehensive income (OCI).

The impacts of recognizing the Company's share-based payments with graded vesting provisions as a series of individual awards under IFRS 2 were increases to staff costs and employee benefits expense of $1 million for the three and six months ended June 30, 2010.

As a result of the IFRS adjustments, the impacts to income taxes for the three and six months ended June 30, 2010 were increases in recoveries of $4 million and $3 million respectively.

The remaining adjustments impact OCI:

- The impacts of using Primary Energy Recycling Corporation's share price as a proxy to determine the fair value of the Company's investment in Primary Energy Recycling Holdings LLC, were increases to OCI of nil (net of nil in income tax expense) and $2 million (net of $1 million in income tax expense) for the three and six months ended June 30, 2010 respectively.
- The impacts of incorporating the entity's credit risk into the hedge effectiveness testing were increases in OCI of $1 million (net of income tax expense of nil) and nil (net of income tax expense of nil) for the three and six months ended June 30, 2010 respectively.
- As a result of the adjustments made by the Company on transition and up to June 30, 2010, there were net decreases to OCI for an increase in the unrealized losses on translating the Company's foreign operations of $1 million (net of $3 million in income tax expense) and nil (net of $1 million in income tax expense) for the three and six months ended June 30, 2010 respectively.

(j) Presentation reclassifications:

The following items have been reclassified:

- In accordance with IFRIC 18, International Financial Reporting Interpretations Committee (IFRIC) 18 requires that contributions received with respect to the construction of property, plant and equipment and used to provide goods or services, be classified as deferred revenue. Accordingly, revenue should be recorded as the contributions are realized, whereas, previously under GAAP, this was recorded as a reduction of depreciation. The impacts were increases to other income and increases to depreciation expense of $1 million and $2 million for the three and six months ended June 30, 2010 respectively.
- The Company has chosen to present its statement of income by nature of expense. Certain amounts have been reclassified on the statement of income to align expenses with the revised presentation format. The most significant adjustment is to separately disclose staff costs and employee benefits expenses. This reclassification resulted in other raw materials and operating charges and other administrative expenses increasing by $37 million and $9 million respectively for the three months ended June 30, 2010 and $56 million and $19 million respectively for the six months ended June 30, 2010.
- In accordance with IAS 37, the unwinding of the discount on provisions should be presented as a finance expense. Under Canadian GAAP, it was presented as part of depreciation and amortization. The impacts of this difference were to reclassify $3 million and $4 million for the three and six months ended June 30, 2010 respectively.

14. Comparative figures:

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