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

For immediate release October 29, 2010

Capital Power reports third quarter 2010 results and announces completion of Island Generation acquisition

EDMONTON, Alberta – Capital Power Corporation ("Capital Power", or the "Company") (TSX: CPX) today released its financial results for the three and nine month periods ended September 30, 2010. Normalized net income, after adjusting for one-time items and fair value adjustments, was $12 million or $0.55 per share in the third quarter of 2010 while net income was $7 million or $0.32 per share for the same period. For the nine month period ending September 30, 2010, normalized net income was $25 million or $1.15 per share and net income was $12 million or $0.55 per share.

"The Company had solid performance in the third quarter of 2010," said Brian Vaasjo, President and CEO of Capital Power Corporation. "Although Alberta spot power prices remained low in the third quarter, the strategy to sell forward a substantial portion of our Alberta power portfolio for 2010 when prices were higher, has resulted in our captured price being 26% higher than the average Alberta spot power price for the first nine months of the year. Our financial performance in the first nine months of the year, as measured by normalized earnings per share, is tracking slightly ahead of plan and we are well positioned to meet our earlier full year guidance for 2010."

"On October 19th, we successfully completed the acquisition of the 275 megawatt Island Generation facility. Island Generation represents an important milestone in Capital Power's growth strategy as it is the first addition to our fleet via acquisition. In addition, with close to 700 megawatts committed in development opportunities, we continue to make progress towards our growth objective of owning or operating 10,000 megawatts by 2020."

Operational and Financial Highlights[1] (unaudited) *(millions of dollars except per share and operational amounts)*	**Three months ended September 30, 2010**	**Nine months ended September 30, 2010**
Electricity generation (GWh)	3,635	10,352
Generation plant availability (%)	95%	92%
Revenues	508	1,320
Gross margin[2]	229	565
Operating margin[2]	176	398
Normalized net income [2]	12	25
Normalized earnings per share[2]	$0.55	$1.15
Net income	7	12
Earnings per share	$0.32	$0.55
Dividends declared per share	$0.315	$0.945
Funds from operations[2]	106	271
Funds from operations excluding non-controlling interests in CPILP[2]	86	207
Capital expenditures	74	285

(1) The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the Consolidated Financial Statements for the nine months ended September 30, 2010.
(2) Gross margin, Operating margin, Normalized net income, Normalized earnings per share, Funds from operations, and Funds from operations excluding non-controlling interests in CPILP are non-GAAP financial measures and do not have standardized meanings under Canadian GAAP, and therefore, may not be comparable to similar measures used by other enterprises. Reconciliations of these non-GAAP financial measures to net income are included in the Company's Management's Discussion and Analysis dated October 29, 2010.

Corporate Updates

Review of strategic alternatives for Capital Power Income L.P. (CPILP)

On October 5, 2010 Capital Power Corporation and CPILP jointly announced that CPILP will initiate a process to review its strategic alternatives. Capital Power Corporation will support the review of strategic alternatives, and if the process results in a determination to proceed with a sale of CPILP, Capital Power Corporation does not intend to participate as a prospective buyer.

The initiation of the strategic review is not in response to any proposed transaction for CPILP, nor can there be any assurance that it will lead to a transaction.

The process to review strategic alternatives is anticipated to take place over the next several months. During this period it will be business as usual for CPILP and Capital Power Corporation and it is anticipated that CPILP will continue to provide the same amount of monthly distributions to its unitholders, and maintain the same investor proposition that it offers today. Capital Power Corporation, through wholly owned subsidiaries, will continue to manage CPILP assets and seek growth opportunities that fit CPILP's strategy.

Acquisition of Island Generation Facility

CPLP's acquisition of Island Generation from Kelson Canada Inc. closed on October 19, 2010. Island Generation is a 275 MW gas-fired combined cycle power plant at Campbell River, British Columbia. The Company has initially financed the purchase price of approximately $207 million, plus closing costs less approximately $2 million of working capital adjustments, with funds drawn on credit facilities.

Island Generation is fully contracted from April 2010 to April 2022 under a tolling arrangement where BC Hydro is responsible for the fuel supply to the facility. Commissioned in 2002, Island Generation is consistent with Capital Power's fleet of young assets that deploy efficient technologies.

The Island Generation facility is expected to be modestly and immediately accretive to earnings, and more significantly accretive to cash flow, based on the Electricity Purchase Arrangement (EPA) terms and Capital Power's expectation that the EPA will not be considered a capital lease for accounting purposes.

A+ rating for Capital Power's first Corporate Responsibility Report

Capital Power has achieved an A+ rating for its 2009 Corporate Responsibility Report, "Moving in the Right Direction". The report documents the impacts that Capital Power has on the environment, and its employees, shareholders, and communities. The internationally-recognized A+ standard, defined by the Global Reporting Initiative, has been independently verified by Pricewaterhouse Coopers LLP.

"Capital Power's first corporate responsibility report is a concrete example of the Company's values of acting with integrity and transparency, being accountable and environmentally responsible, and working safely towards a zero-injury workplace," said Capital Power President & CEO Brian Vaasjo. "Capital Power's diligence in tracking, monitoring, and reporting throughout the year, and the input of our people from across North America, were critical factors in achieving an A+ rating for the report."

Following are some highlights from the report:

- Net generation was 18.3 million megawatt hours (MWh) in 2009, an increase of approximately 12% over the previous year (under Capital Power's predecessor company). Increased generation in 2009 was primarily due to a return to normal levels of production at the Genesee facility in Alberta, which underwent approximately 66 days of planned and unplanned shutdowns in 2008. Added production from new facilities, such as the Morris co-generation plant in Illinois (acquired by Capital Power Income L.P. in late 2008), and two new units at the Clover Bar Energy Centre in Edmonton, Alberta, also contributed to increased production in 2009.
- Greenhouse gas emissions intensity improved in 2009. Capital Power's facilities emitted 0.71 tonnes of CO_2 per MWh of power produced, compared to 0.73 tonnes per MWh in 2008. Although production volumes increased 12%, total CO_2 emissions rose by only 8%. Emissions of particulate matter, nitrogen oxide and mercury also increased. Both the volume and intensity of sulphur dioxide emissions were lower in 2009, with reductions of 11% and 21% respectively.
- Capital investments improved environmental performance at a number of facilities. An investment of US$87 million in the Southport and Roxboro plants in North Carolina increased plant efficiency and reduced the volume of coal used. Upgrades to a combined heat and power facility in North Island, California are expected to reduce nitrogen oxide emissions to one-sixth of previous levels.
- Total recordable injuries and lost time injury rates were lower than the average of the three years prior.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on November 1, 2010 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: 56777#

A replay of the conference call will be available following the call at: (877) 353-9587 (toll-free) and entering pass code 388630. The replay will be available until midnight on November 30, 2010.

Interested parties may also access the live webcast on the Company's website at www.capitalpower.com with an archive of the webcast available following the conference call.

Non-GAAP Financial Measure

Operating margin is not a defined financial measure according to Canadian generally accepted accounting principles (GAAP) and does not have a standardized meaning prescribed by GAAP. Therefore, operating margin may not be comparable to similar measures presented by other enterprises.

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 review of strategic alternatives for CPILP, its potential outcome, and the intention of Capital Power to support the review of strategic alternatives but not participate as a prospective buyer if a sale were to occur; (ii) expectations regarding the timing of the CPILP strategic review process and that during the review process CPILP will continue its business as usual, provide the same amount of monthly distributions to its unitholders and maintain the same proposition it offers today; (iii) Capital Power's intention to continue managing CPILP assets and seek growth opportunities that fit CPILP's strategy; (iv) expectations that Island Generation will be modestly and immediately accretive to earnings and cash flow; and (v) expectations regarding BC Hydro's responsibility for the fuel supply to the Island Generation Facility.

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; (iii) the Company's financial position and credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets; (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 including Island Generation; (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 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; and (xxii) accounting treatment for Island Generation.

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; (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 and investments including Island Generation; and (xvii) the tax attributes of and implications of any acquisitions. 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
Capital Power is a growth-oriented North American independent power producer, building on more than a century of innovation and reliable performance. The Company'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 32 facilities in Canada and the U.S. totaling nearly 3,800 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
September 30, 2010

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated October 29, 2010, should be read in conjunction with the unaudited interim consolidated financial statements of Capital Power Corporation (the Company) and its subsidiaries for the nine months ended September 30, 2010, the audited consolidated financial statements and MD&A of the Company for the six months ended December 31, 2009 and the cautionary statement regarding forward-looking information which begins on page 30. 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 three and nine months ended September 30, 2010 is based on the unaudited interim consolidated financial statements of the Company, which were prepared in accordance with Canadian generally accepted accounting principles (GAAP), and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors has approved this MD&A.

On July 9, 2009, the Company completed its initial public offering (IPO) and acquisition of power generation assets and operations (the Reorganization) from EPCOR Utilities Inc. (EPCOR). The Company commenced operations in July 2009 and its first fiscal year ended on December 31, 2009. Accordingly, the Company's unaudited financial statements for the nine months ended September 30, 2010 include prior year comparative information for the three months ended September 30, 2009. To facilitate the analysis of the Company's unaudited financial statements this MD&A includes unaudited pro forma consolidated financial information for the three and nine months ended September 30, 2009. As six months of the nine-month comparative period predate the closing of the IPO, this comparative financial information is provided for reference purposes only and is not intended to be a comprehensive comparison of financial results.

The Company's outstanding share capital on September 30, 2010 consisted of 21.767 million common shares, 56.625 million special voting shares and one special limited voting share.

The Business

The Company's power generation operations and assets are owned by Capital Power LP (CPLP), a subsidiary of the Company. At September 30, 2010, the Company held approximately 21.75 million general partnership units and one common limited partnership unit of CPLP which represented approximately 27.8% and zero %, respectively, of CPLP, and EPCOR held 56.625 million exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) representing approximately 72.2% of CPLP. The general partner of CPLP is wholly-owned by Capital Power and EPCOR's representation on the Board of Directors does not represent a controlling vote. Accordingly, Capital Power controls CPLP and the operations of CPLP have been consolidated for financial statement purposes.

The assets used in the operating business of the Company are primarily held through CPLP and its subsidiary entities. The interests held by the Company outside CPLP are not material to the Company's consolidated operations, assets, liabilities and operating business or the Company's consolidated financial statements and are primarily a consequence of the Company's organizational structure. The primary assets and liabilities of the Company that are held outside of CPLP are:

- The Company's indirect interest in the general partners of the Canadian limited partnerships through which CPLP's Canadian power generation facilities are held, representing an equity interest of 1% or less in each of these partnerships;
- The Company's indirect interest in a subsidiary entity (CP Regional Power Services Limited Partnership) that provides management and administrative services to Capital Power Income L.P. (CPILP) and the

Company's Canadian limited partnerships, under various management and operation agreements;

- Future income tax assets and liabilities resulting primarily from the Company's interest in CPLP which, as a limited partnership is not a taxable entity; and
- Certain natural gas customer contracts for which a non-current liability has been recorded on the consolidated balance sheet to reflect the estimated loss in fair value of the contracts which arose at the time of acquisition of these contracts from EPCOR.

These items did not have a material impact on the Company's consolidated revenues, income from continuing operations, or income before income tax expense and non-controlling interests for the nine months ended September 30, 2010 or on the Company's consolidated total assets or total liabilities as at September 30, 2010. CPLP's consolidated revenues, income from continuing operations, income before income tax expense and non-controlling interests for the nine months ended September 30, 2010, and consolidated total assets and total liabilities as at September 30, 2010 represent 97% or more of the corresponding consolidated items of the Company.

Financial Highlights

(unaudited, $millions, except earnings (loss) per share)	Three months ended		Nine months ended	
	Sept 30, 2010	Sept 30, 2009	Sept 30, 2010	Sept 30, 2009(2)
Revenues	$ 508	$ 511	$ 1,320	$ 1,661
Gross margin(1)	229	218	565	667
Operating margin(1)	176	169	398	501
Net income	7	14	12	44
Earnings per share(4)	$ 0.32	$ 0.64	$ 0.55	N/A
Fully diluted earnings per share(3)(4)	$ 0.31	$ 0.59	$ 0.55	N/A
Normalized earnings per share(1)(4)	$ 0.55	$ 0.42	$ 1.15	N/A
Funds from operations(1)(4)	106	93	271	N/A
Capital expenditures(4)	74	108	285	N/A
Long-term debt including current portion(4)	1,773	1,771	1,773	N/A
Total assets(4)	5,005	4,918	5,005	N/A

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

(2) Financial highlights for the nine months ended September 30, 2009 are unaudited pro forma consolidated financial information included in the Pro forma Consolidated Financial Information section.

(3) 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 on a one-for-one basis) held by EPCOR.

(4) Certain financial highlights are not applicable (N/A) for the nine months ended September 30, 2009 as the unaudited pro forma financial information does not include a balance sheet, a statement of cash flows or earnings per share.

Funds from Operations

(unaudited, $millions)	Three months ended				
	Sept 30, 2010	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Funds from operations excluding non-controlling interests in CPILP(1)	$ 86	$ 34	$ 87	$ 49	$ 70
Funds from operations(1)	106	53	112	71	93

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

Funds from operations are cash provided by operating activities excluding changes in working capital. Funds from operations excluding non-controlling interests in CPILP for the third quarter were in line with management's expectations. The increase compared with the second quarter of 2010 was primarily due to higher operating margins, excluding unrealized fair value changes, from the Alberta contracted plants and the Alberta commercial plants and portfolio. There were no major outages at the Alberta contracted plants in the third quarter whereas there was a scheduled outage at Genesee 2 in the second quarter of 2010. Accordingly, availability penalties and maintenance costs reduced funds from operations in the second quarter. The operating margin, excluding unrealized fair value changes, from the Alberta commercial plants and portfolio was higher in the third quarter due to the recognition of an estimated business interruption insurance recovery relating to the Clover Bar Energy Centre Unit 2 outage in March 2010 through to September 2010.

Since the non-controlling interests in CPILP's funds from operations were approximately 70.2% at September 30, 2010 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. Funds from operations excluding CPILP increased $52 million and funds from operations increased $53 million in the third quarter compared with the second quarter as CPILP's funds from operations were relatively stable over the two periods.

Normalized Net Income and Normalized Earnings per Share

(unaudited, $millions except earnings (loss) per share)	Three months ended				
	Sept 30, 2010	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Earnings (loss) per share	**$ 0.32**	**$ (0.37)**	**$ 0.60**	**$ 0.33**	**$ 0.64**
Net income (loss)	**7**	**(8)**	**13**	**7**	**14**
Adjustments	5	9	(1)	(3)	(5)
Normalized net income[1]	**12**	**1**	**12**	**4**	**9**
Normalized earnings per share[1]	**$ 0.55**	**$ 0.05**	**$ 0.55**	**$ 0.18**	**$ 0.42**

(1) Normalized net income and normalized earnings per share are non-GAAP measures. See Non-GAAP Financial Measures.

Normalized net income for the third quarter was slightly ahead of management's expectations and higher in comparison to the second quarter of 2010. The quarter-over-quarter increase was primarily due to higher operating margins, excluding unrealized fair value changes, from the Alberta contracted plants and Alberta commercial plants and portfolio, as described above under Funds from Operations.

The Company uses normalized net income and normalized earnings per share to measure performance by period on a comparable basis. Normalized net income is based on net income as reported in the consolidated financial statements and adjusted for items that are not reflective of performance in the period such as fair value changes, impairments, unusual tax adjustments and gains or losses on disposal of assets and on unusual contracts. Normalized earnings per share for the third quarter of 2010 reflect normalized net income divided by 21.77 million weighted average common shares outstanding. See Non-GAAP Financial Measures.

Pro forma Consolidated Financial Information

The pro forma consolidated financial information for the nine months ended September 30, 2009 has been prepared by management and presents the effects of the completion of the IPO, the Reorganization and the related use of the net proceeds of the IPO as if they occurred on January 1, 2008. The unaudited pro forma consolidated financial information for the nine months ended September 30, 2009 is based on currently available information and assumptions that management believes provide a reasonable basis for presenting the significant effects of the completion of the IPO and the Reorganization. In management's opinion, all material adjustments necessary to present fairly the pro forma consolidated financial information have been made. The unaudited pro forma consolidated financial information is presented for information purposes only and is not necessarily indicative of what the results of operations would have been had the completion of the IPO and the Reorganization occurred at the dates indicated, nor does it purport to be indicative of the results of operations for any future period. Actual adjustments differed from the pro forma adjustments.

The unaudited pro forma consolidated financial information has been prepared in accordance with Canadian GAAP consistent with the significant accounting policies described in note 2 to the audited consolidated financial statements of the Company for the six months ended December 31, 2009. The presentation of the unaudited pro forma consolidated information conforms to the presentation of both the unaudited financial statements of the Company for the nine months ended September 30, 2010 and the audited financial statements of the Company for the six months ended December 31, 2009.

(unaudited, $millions)	Three months ended		Nine months ended	
	Sept 30, 2010	Sept 30, 2009	Sept 30, 2010	Sept 30, 2009[1]
Revenues	$ 508	$ 511	$ 1,320	$ 1,661
Energy purchases and fuel	279	293	755	994
	229	218	565	667
Operations, maintenance and direct administration	48	44	153	151
Indirect administration	38	27	95	96
Property taxes	5	5	14	15
Depreciation, amortization and asset retirement accretion	48	44	146	135
Foreign exchange losses	1	3	-	5
Gain on sale of power syndicate agreement	-	-	(28)	(30)
Net financing expenses	25	17	62	60
	165	140	442	432
Income before income tax expense and non-controlling interests	64	78	123	235
Income tax expense (recovery)	17	(2)	10	1
Income before non-controlling interests	47	80	113	234
Non-controlling interests	40	66	101	190
Net income	**$ 7**	**$ 14**	**$ 12**	**$ 44**

(1) Unaudited pro forma consolidated information for the nine months ended September 30, 2009 conforms to the presentation adopted for the nine months ended September 30, 2010.

Consolidated Net Income

(unaudited, $millions)	Three months	Nine months
Net income for the periods ended September 30, 2009[1]	**$ 14**	**$ 44**
Higher Alberta commercial plants and portfolio operating margin	18	19
Higher (lower) Alberta contracted plants operating margin	1	(25)
Higher income taxes	(19)	(9)
(Higher) lower indirect administration	(11)	1
Higher net financing expenses	(8)	(2)
Unrealized changes in the fair value of CPILP’s derivative instruments	(7)	(14)
Higher depreciation	(4)	(11)
Unrealized changes in the fair value of CPLP’s energy derivative instruments and natural gas inventory held for trading	(2)	(70)
Lower other portfolio activities operating margin	(1)	(11)
Other	-	1
	(33)	(121)
Lower (higher) non-controlling interests:		
- CPLP	14	80
- CPILP	13	14
- Preferred share dividends paid by subsidiary company	(1)	(5)
	26	89
Decrease in net income	(7)	(32)
Net income for the periods ended September 30, 2010	**$ 7**	**$ 12**

(1) Net income for the nine months ended September 30, 2009 is based on pro forma consolidated information.

Net income decreased $7 million and $32 million for the three and nine months ended September 30, 2010, respectively compared with the corresponding periods in 2009 due to the net impact of the following:

- Alberta commercial plants and portfolio operating margin was higher primarily due to higher margins realized on merchant trading and an estimated $8 million business interruption insurance recovery relating to Clover Bar Energy Centre Unit 2, which was recorded in the third quarter of 2010.

- The operating margin for Alberta contracted plants was reduced by net availability penalties of $12 million and maintenance costs of $13 million for the 21-day Genesee 2 outage in the second quarter of 2010 whereas there were no outages in the nine months ended September 30, 2009.

- Income taxes were higher primarily due to the recognition in the third quarter of 2010 of an $11 million future income tax liability relating to the review of strategic alternatives with respect to the Company's investment in CPILP, as discussed under Significant Events.

- Indirect administration expenses increased in the third quarter of 2010 primarily due to the recognition of $7 million for the fair value of the Company's obligation to EPCOR for the operations and maintenance costs of EPCOR's Rossdale plant and related assets until 2019. Indirect administration expenses decreased in the nine months ended September 30, 2010 primarily due to lower business development costs. In addition, transition costs related to the Reorganization were incurred in the second quarter of 2009 whereas no corresponding expense was incurred in the periods ending September 30, 2010.

- Financing expenses for the three and nine months ended September 30, 2010 included unrealized losses of $7 million and $11 million, respectively, for the decrease in the fair value of two forward bond sale contracts entered into in the second quarter of 2010. These losses were partly offset by higher interest capitalized for construction work in progress and lower CPILP financing expenses, primarily in the first half of 2010 compared with the corresponding period in 2009. The decrease in CPILP's financing expenses was primarily due to the impact of a weaker U.S. dollar relative to the Canadian dollar on the translation of U.S. dollar interest expense.

- The unrealized changes in the fair value of CPILP's derivative instruments reflected smaller gains on foreign exchange contracts in the three and nine months ended September 30, 2010 compared with the corresponding periods in 2009. The unrealized gains in both years were due to strengthening future prices for the Canadian dollar relative to the U.S. dollar. The fair value of CPILP's natural gas supply contracts decreased in the nine months ended September 30, 2010 and 2009 due to decreases in the future prices for natural gas. The unrealized fair value loss recognized in the income statement was smaller in the current year period as CPILP designated certain contracts as hedges for accounting purposes effective July 31, 2009 and the fair value losses relating to those contracts were recorded in other comprehensive income.

- The unrealized changes in the fair value of CPLP's derivative instruments and natural gas storage held for trading that were not designated as hedges for accounting purposes, reflected the impact of smaller decreases and less volatility in the Alberta forward power prices on portfolio positions for these instruments in the first nine months of 2010 compared with the corresponding period in 2009.

- The operating margin for other portfolio activities decreased primarily due to lower natural gas speculative trading profit and fewer electricity import and export market trading opportunities as a result of lower price spreads and less volatility in prices in the first nine months of 2010.

- The decrease in non-controlling interests reflected lower income before income taxes from CPLP and 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.

The Company's operating results for the third quarter were slightly ahead of management's expectations. However, the income tax impact of the decision to review strategic alternatives regarding the Company's investment in CPILP as discussed under Significant Events, was not previously recognized. Accordingly, excluding this provision of $11 million before non-controlling interest to recognize a future income tax liability associated with the Company's investment in CPILP, as well as unrealized fair value changes, the Company's outlook for the full year results is consistent with the discussion in the Outlook Section of the December 31, 2009 MD&A. Operating results in the first quarter of 2010 were better than expected followed by a poor second quarter performance and a recovery in the third quarter. Other updates specific to the fourth quarter of 2010 are as follows.

The Company has a 94% total plant (excluding CPILP plants) availability target for 2010 which takes into account reduced availability for the scheduled outages at Genesee 2 in May and Genesee 3 in the fourth quarter. However, primarily due to issues with the Clover Bar Energy Centre Unit 2, the Company anticipates that the total plant (excluding CPILP plants) availability will be 90% for the year.

The second unit at Clover Bar Energy Centre was taken offline in March due to mechanical issues which were addressed under warranty from the supplier. The unit was back online on September 22, 2010 and an estimated insurance recovery for business interruption was recorded in the third quarter. The claim is expected to be settled before the end of the first half of 2011. The units at Clover Bar Energy Centre are peaking plants which are intended to enhance the Company's ability to physically manage its Alberta portfolio. Accordingly, the Company relied on these units while Genesee 3 was offline for planned maintenance for the month of October. The maintenance cost for Genesee 3 outage is still estimated to be approximately $7 million.

The forecast generation from the base-load plants in the Alberta commercial portfolio for the balance of 2010 is sold forward at an average price of $60/megawatt hour (MWh). For 2011, approximately 70% of the portfolio has been sold forward at an average contracted price in the mid-$60/MWh range.

Fourth quarter earnings will also benefit from the addition of the Island Generation Facility (Island Generation) to the Company's fleet of assets on October 19, 2010 (see Subsequent Event). Based on the terms of the Electricity Purchase Arrangement (EPA), plant operating parameters of the turbine and management's forecasted dispatch of the facility, the Company anticipates an operating margin contribution of approximately $4 million from Island Generation for the fourth quarter of 2010 and $24 million to $28 million in 2011. Operating margin is a non-GAAP financial measure. See Non-GAAP Financial Measures.

Changes in CPILP's outlook that may result from a review of its strategic alternatives (see Significant Event) will depend on the outcome of the review process. During the review process over the next few months it is anticipated that CPILP will continue its business as usual and will provide the same amount of monthly distributions to its unitholders.

CPILP continues to face uncertainty in the timing of the finalization and terms of new power purchase arrangements (PPAs) for its North Carolina facilities. CPILP and Progress Energy Inc. have been in negotiations but, to date, have been unable to finalize new PPAs that are acceptable to both parties. CPILP filed for arbitration with the North Carolina Utilities Commission (NCUC) and expects their decision during the fourth quarter of 2010. It is not certain whether the final contract terms will result in positive cash provided by operating activities for the facilities or achieve previous expectations of accretion from the North Carolina enhancement project.

Capital expenditures, excluding CPILP's capital expenditures, are expected to be approximately $88 million in the last three months of 2010 or $345 million for the full year. This full year estimate includes the following changes to the forecast included in the December 31, 2009 MD&A: an addition of $60 million for wind power development projects and a $20 million reduction in spending on Keephills 3 which will be incurred in 2011. The changes in the estimated timing of capital expenditures for Keephills 3 are not expected to impact the total cost of the project.

Significant Event

Review of strategic alternatives for CPILP

On October 5, 2010 Capital Power Corporation and CPILP jointly announced that CPILP will initiate a process to review its strategic alternatives. Capital Power Corporation will support the review of strategic alternatives, and if the process results in a determination to proceed with a sale of CPILP, Capital Power Corporation does not intend to participate as a prospective buyer.

The initiation of the strategic review is not in response to any proposed transaction for CPILP, nor can there be any assurance that it will lead to a transaction.

The process to review strategic alternatives is anticipated to take place over the next several months. During this period it will be business as usual for CPILP and Capital Power Corporation and it is anticipated that CPILP will continue to provide the same amount of monthly distributions to its unitholders, and maintain the same investor proposition that it offers today. Capital Power Corporation, through wholly owned subsidiaries, will continue to manage CPILP assets and seek growth opportunities that fit CPILP's strategy.

Subsequent Event

Acquisition of Island Generation Facility

CPLP's acquisition of Island Generation from Kelson Canada Inc. closed on October 19, 2010. Island Generation is a 275 MW gas-fired combined cycle power plant at Campbell River, British Columbia. The Company has initially financed the purchase price of approximately $207 million, plus closing costs less approximately $2 million of working capital adjustments, with funds drawn on credit facilities.

Island Generation is fully contracted from April 2010 to April 2022 under a tolling arrangement where BC Hydro is responsible for the fuel supply to the facility. Commissioned in 2002, Island Generation is consistent with Capital Power's fleet of young assets that deploy efficient technologies.

The Island Generation facility is expected to be modestly and immediately accretive to earnings, and more significantly accretive to cash flow, based on the EPA terms and Capital Power's expectation that the EPA will not be considered a capital lease for accounting purposes.

Operating margin (See Non-GAAP Financial Measure) for the Island Generation facility is expected to be approximately $4 million for 2010 and $24 million to $28 million in 2011. Cash provided by operating activities is expected to be approximately $3 million for 2010 and $23 million to $26 million in 2011. While the operating margin is expected to be relatively stable over the term of the EPA, cash provided by operating activities is expected to decline on average by 7% per year.

Corporate Update

Corporate Responsibility Report

Capital Power Corporation received an A+ rating for its 2009 Corporate Responsibility Report, "Moving in the Right Direction." The report documents the impacts that Capital Power has on the environment, employees, shareholders, and communities. The internationally-recognized A+ standard, defined by the Global Reporting Initiative, has been independently verified by Pricewaterhouse Coopers LLP. The full report can be downloaded from Capital Power's web-site at www.capitalpower.com.

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) CPILP plants, and (v) other portfolio activities.

Generation volume

(unaudited, GWh)	Three months ended		Nine months ended	
Electricity generation[(1)]	Sept 30, 2010	Sept 30, 2009	Sept 30, 2010	Sept 30, 2009
Alberta commercial plants				
Genesee 3	475	470	1,390	1,419
Joffre	67	89	201	252
Clover Bar Energy Centre 1, 2 and 3[(2)]	37	16	182	25
Taylor Coulee Chute	7	12	10	19
Clover Bar Landfill Gas	9	9	29	27
Weather Dancer	-	-	-	1
	595	596	1,812	1,743
Alberta contracted plants				
Genesee 1	841	837	2,434	2,446
Genesee 2	824	801	2,220	2,443
	1,665	1,638	4,654	4,889
Ontario and British Columbia contracted plants				
Kingsbridge 1	18	14	66	71
Miller Creek	46	47	88	79
Brown Lake	5	11	29	38
	69	72	183	188
Total excluding CPILP plants	**2,329**	**2,306**	**6,649**	**6,820**
CPILP plants[(3)]	1,306	1,228	3,703	3,560
Total plants	**3,635**	**3,534**	**10,352**	**10,380**
Sundance PPA	**680**	**448**	**2,159**	**1,778**

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

(2) Clover Bar Energy Centre includes Units 1, 2 and 3 as of their commercial operation dates, March 10, 2008, September 1, 2009 and December 16, 2009, respectively.

(3) CPILP excludes Castleton which was sold on May 26, 2009.

Plant availability

(unaudited)	Three months ended		Nine months ended	
Generation plant availability[1]	Sept 30, 2010	Sept 30, 2009	Sept 30, 2010	Sept 30, 2009
Alberta commercial plants				
Genesee 3	99%	97%	98%	98%
Joffre	98%	96%	94%	92%
Clover Bar Energy Centre 1, 2 and 3[3]	63%	96%	62%	98%
Taylor Coulee Chute	100%	100%	96%	100%
Clover Bar Landfill Gas	92%	90%	94%	90%
Weather Dancer	0%	55%	27%	65%
	86%	96%	84%	96%
Alberta contracted plants				
Genesee 1	100%	100%	99%	99%
Genesee 2	97%	95%	90%	98%
	99%	97%	95%	99%
Ontario and British Columbia contracted plants				
Kingsbridge 1	99%	99%	99%	99%
Miller Creek	96%	88%	76%	86%
Brown Lake	93%	97%	96%	97%
	97%	94%	90%	94%
Average excluding CPILP plants[2]	**93%**	**97%**	**90%**	**97%**
CPILP plants[4]	97%	93%	94%	92%
Average all plants[2]	**95%**	**95%**	**92%**	**95%**
Sundance PPA	**88%**	**69%**	**93%**	**84%**

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

(3) Clover Bar Energy Centre includes Units 1, 2 and 3 as of their commercial operation dates, March 10, 2008, September 1, 2009 and December 16, 2009, respectively.

(4) CPILP excludes Castleton which was sold on May 26, 2009.

The increase in total plant electricity generation excluding the Sundance PPA, for the three months ended September 30, 2010 compared with the corresponding period in 2009 primarily relates to the CPILP plants. Dispatch of CPILP's North Carolina facilities was higher in the third quarter of 2010 and there was a temporary outage at CPILP's Williams Lake plant in the third quarter of 2009 as a result of reduced production from the plant's major wood waste suppliers. There were no such outages in the three months ended September 30, 2010.

The decrease for the nine months ended September 30, 2010 compared with the corresponding period in 2009 primarily relates to the Genesee units 1 and 2, partly offset by higher output from the CPILP plants as discussed above, and Clover Bar Energy Centre. In the second quarter of 2010, Genesee 2 experienced a 21-day outage and all three Genesee units were impacted by curtailments to facilitate transmission upgrades.

Clover Bar Energy Centre generation was higher as it included all three units for the first nine months of 2010 compared with Unit 1 for the nine months ended September 30, 2009 and Unit 2 as of September 1, 2009, the date it commenced operations. Unit 2 went offline on March 8, 2010 due to a mechanical failure in the main turbine section. The unit came back online on September 22, 2010.

Sundance Unit 5 was offline for 47 days in the third quarter of 2009. There were no similar outages in the corresponding period in 2010.

Financial results

(unaudited, $millions)	Three months ended Sept 30, 2010	Three months ended Sept 30, 2009	Nine months ended Sept 30, 2010	Nine months ended Sept 30, 2009[2]
Revenues				
Alberta commercial plants and portfolio optimization	$ 250	$ 238	$ 682	$ 805
Alberta contracted plants	71	70	198	212
Ontario and British Columbia contracted plants	4	4	11	12
CPILP plants	130	123	385	403
Other portfolio activities	15	23	83	110
Inter-plant category transaction eliminations	(10)	(10)	(30)	(32)
	460	448	1,329	1,510
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	37	30	(6)	100
Unrealized changes in fair value of CPILP's foreign exchange contracts	11	33	(3)	51
	48	63	(9)	151
	$ 508	**$ 511**	**$ 1,320**	**$ 1,661**
Gross margin[1]				
Alberta commercial plants and portfolio optimization	72	50	197	170
Alberta contracted plants	57	58	159	178
Ontario and British Columbia contracted plants	4	4	11	12
CPILP plants	76	77	221	237
Other portfolio activities	9	8	32	43
Inter-plant category transaction eliminations	(9)	(8)	(27)	(29)
	209	189	593	611
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	14	16	(13)	57
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	6	13	(15)	(1)
	20	29	(28)	56
	$ 229	**$ 218**	**$ 565**	**$ 667**
Operating margin[1]				
Alberta commercial plants and portfolio optimization	$ 59	$ 41	$ 161	$ 142
Alberta contracted plants	48	47	113	138
Ontario and British Columbia contracted plants	3	3	7	8
CPILP plants	48	48	142	141
Other portfolio activities	1	2	6	17
Inter-plant category transaction eliminations	(3)	(1)	(3)	(1)
	156	140	426	445
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	14	16	(13)	57
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	6	13	(15)	(1)
	20	29	(28)	56
	$ 176	**$ 169**	**$ 398**	**$ 501**

(1) The results by plant category, except for gross margin and operating margin, have been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

(2) The presentation of results by plant category for the nine months ended September 30, 2009 conforms to the presentation for the nine months ended September 30, 2010. See Pro forma Consolidated Financial Information.

Spot price averages	Three months ended Sept 30, 2010	Three months ended Sept 30, 2009	Nine months ended Sept 30, 2010	Nine months ended Sept 30, 2009
Alberta power ($/MWh)	35.77	49.49	52.55	48.33
Eastern region power ($/MWh)	42.72	21.94	37.74	29.25
Western region power (Mid-C) ($/MWh)	33.43	35.67	33.69	33.67
Alberta natural gas (AECO) ($/Gj)[(1)]	3.36	2.81	3.93	3.45

Capital Power's Alberta portfolio's realized power price ($/MWh)[(2)]	66	54	66	58

(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 was $35.77/MWh for the quarter and $52.55/MWh for the nine months ended September 30, 2010. Despite a low average spot price for the nine month period of 2010, the Company's quarterly average realized price for the Alberta commercial portfolio was consistent, (approximately $66/MWh for the three and nine months ended September 30, 2010) as a significant portion of the Company's Alberta portfolio was sold forward at fixed prices under contracts with commercial and industrial customers or under merchant and wholesale financial contracts.

The gross margin and operating margin for the Alberta commercial plants and portfolio were higher in the three and nine months ended September 30, 2010 compared with the corresponding periods in 2009 primarily due to higher margins realized on the merchant trading portfolio in the third quarter and an estimated business interruption insurance recovery that was recognized in the third quarter of 2010. The commodity portfolio optimization strategies that were successful in the first quarter were partly offset by an unfavourable impact in the second quarter.

Higher Alberta spot prices and higher volatility in those prices in the second quarter of 2010, provided more opportunities to dispatch the Clover Bar Energy Centre and contributed to the increased operating margin in the nine months ended September 30, 2010 compared to the corresponding period in the prior year. This was partly offset by reduced generation as a result of the sale of the Company's interest in the Battle River PPA in January 2010.

Clover Bar Energy Centre Unit 2 was offline from March 8, 2010 to September 22, 2010 due to a mechanical failure in the main turbine section. The Company recorded an estimated recovery of $8 million from business interruption insurance and expects to file the insurance claim in November 2010. Although the cost of the repair work on Unit 2 was covered by the original contractor, regular operating and maintenance expenses were higher as more units were in commission in the first nine months of 2010 compared with the prior year.

The increase in revenues from the Alberta commercial plants and portfolio in the third quarter primarily reflected the impact of lower Alberta power prices on a higher volume of derivative sell contracts that settled in the third quarter of 2010 compared with the corresponding period in 2009 and higher generation from Clover Bar Energy Centre, partly offset by the absence of generation from Battle River. The business interruption insurance recovery was also recognized in revenue in the third quarter of 2010.

The decrease in revenues for the nine month period primarily reflected the impact of higher Alberta power prices on a higher volume of derivative sell contracts that settled in the second quarter of 2010 compared with the second quarter of 2009, as well as lower pricing for the supply of electricity to EPCOR's regulated rate tariff (RRT) customers, primarily for the first quarter of 2010 when Alberta power prices were significantly lower compared with the first quarter of 2009. In addition, generation was reduced by the sale of the Company's interest in the Battle River PPA in January 2010. These decreases were partly offset by higher revenues from the Clover Bar Energy Centre plants as more units were in commission in 2010, and the business interruption insurance recovery.

The decrease in revenue from the Company's RRT business in the nine months ended September 30, 2010 did not have a significant impact on operating margin for the period as the Company's purchases and revenues for this business are equally impacted by changes in the Alberta power price and provide a low margin per MWh.

Alberta contracted plants

The Alberta contracted plants performed as expected in the third quarter of 2010. Revenues for the Alberta contracted plants decreased in the nine months ended September 30, 2010, compared with the corresponding period in 2009 primarily due to $12 million in availability penalties incurred during the 21-day scheduled maintenance outage at Genesee 2 in the second quarter of 2010. The penalties were approximately $6 million higher than anticipated due to higher pricing, which for availability incentive income and penalties is a function of a 30-day rolling average of Alberta power prices. There were no scheduled outages at these plants in the first nine months of 2009. Maintenance costs of $13 million for the outage in 2010 also contributed to a lower operating margin for the Alberta contracted plants.

CPILP plants

CPILP plant revenues increased by $7 million in the three months ended September 30, 2010 compared with the corresponding period in 2009 primarily due to higher revenue and dispatch at the North Carolina facilities, partly offset by lower prices on settled foreign exchange contracts. Revenues for the nine months ended September 30, 2010 decreased $18 million primarily due to lower foreign exchange rates, lower prices on settled foreign exchange contracts and lower revenue at the Kenilworth plant. Revenue from the Kenilworth plant reflected lower fuel recoveries which were driven by lower natural gas supply prices.

There was little change in the third quarter operating margin for the CPILP plants as the increase in revenues was offset by increased fuel expense, primarily for the North Carolina and California facilities. The operating margin for the nine months ended September 30, 2010 was also consistent with the corresponding period in 2009 as the decrease in revenue was offset by lower maintenance expenses primarily at the North Carolina facilities and due to a weaker U.S. dollar relative to the Canadian dollar.

Other portfolio activities

Other portfolio activities include natural gas trading in North American markets and electricity trading in the eastern Canada, U.S. Northeast and U.S. Pacific Northwest markets. Results from natural gas trading reflected lower profit during the nine months ended September 30, 2010 compared with the corresponding period in 2009. In addition, there were fewer trading opportunities in the import and export electricity markets due to lower price spreads between markets and less volatility in prices in the periods ending September 30, 2010. Accordingly, revenues, gross margin and operating margin for both the natural gas and electricity portfolios decreased in the three and nine months ended September 30, 2010 compared with the corresponding periods in 2009.

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

Changes in the fair value of CPLP's derivative electricity and natural gas contracts and natural gas storage held for trading, that were not designated as hedges for accounting purposes, increased the gross margin by $14 million in the third quarter and decreased the gross margin by $13 million in the nine months ended September 30, 2010. In 2009, the fair value changes of these instruments increased the gross margin by $16 million in the third quarter and $57 million in the first nine months. These changes primarily reflected the impact of significant decreases in the Alberta forward power prices in the first and third quarters of 2010 and significant increases in the second quarter of 2010 on portfolio positions for these instruments, and decreases in Alberta forward power prices on portfolio positions during all three quarters of 2009. In addition, Alberta forward power prices were less volatile over the three and nine months ended September 30, 2010 compared with the corresponding periods in 2009.

CPILP's revenues included net gains of $11 million and net losses of $3 million for changes in the fair value of foreign exchange contracts in the three and nine months ended September 30, 2010, respectively compared with net gains of $33 million and $51 million, respectively in the corresponding periods in 2009. The changes in fair value were primarily due to strengthening future prices for the Canadian dollar relative to the U.S. dollar in both years and higher volatility in 2009. For the nine months ended September 30, 2010 these gains were offset by the reversal of unrealized fair value gains on contracts that settled during the period.

CPILP's fuel expense included fair value losses on natural gas supply contracts of $5 million and $12 million in the three and nine months ending September 30, 2010, respectively compared with fair value losses of $20 million and $52 million, respectively in the corresponding periods in 2009. These fair value changes primarily reflected decreases in future prices for natural gas in both years. The fair value changes were smaller in 2010 because CPILP designated certain of its natural gas contracts as hedges for accounting purposes effective July 31, 2009. Accordingly, a $24 million and $49 million decrease in the fair value of the designated contracts for the three and nine months ended September 30, 2010, respectively were recorded in other comprehensive loss / income compared with a $4 million increase for each of the corresponding periods in 2009.

Consolidated Other Expenses

Indirect administration

Indirect administration expenses include the cost of support departments and 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 including carbon capture and storage and integrated gasification combined cycle projects. The increase in the third quarter over the corresponding period in 2009 primarily relates to the recognition of the fair value of the obligation to EPCOR for the ongoing operations and maintenance costs, including a roof replacement, of the Rossdale plant and related assets. The fair value was estimated at $7 million based on the present value of the estimated future cash flows over the ten year term of the contract. See Contractual Obligations. For the nine months ended September 30, 2010 this cost increase was offset by lower business development costs, and transition costs related to the Reorganization that were incurred in the second quarter of 2009.

Net financing expenses

Financing expenses were $8 million and $2 million higher for the three and nine months ended September 30, 2010, respectively compared with the corresponding periods in 2009. Unrealized losses of $7 million and $11 million were recognized in financing expenses in the three and nine months ended September 30, 2010, respectively for the decrease in the fair value of two forward bond sale contracts. These contracts were entered into in the second quarter of 2010 and there were no similar contracts in 2009. In the nine months ended September 30, 2010, this was partly offset by the impact of a weaker U.S. dollar relative to the Canadian dollar on the translation of CPILP's U.S. dollar interest expense. In addition, capitalized interest was higher with no additional increase in borrowings until the latter part of the second quarter of 2010. The Company capitalizes borrowing costs as part of its capital construction projects and the amount capitalized is a function of the cost of the construction in progress. In the nine months ended September 30, 2010, construction work in progress, particularly for Keephills 3, was higher compared with the corresponding period in 2009. See Liquidity and Capital Resources.

Depreciation expense

Depreciation expense was $4 million and $11 million higher for the three and nine months ended September 30, 2010, respectively compared with the corresponding periods in 2009. The increases were primarily due to higher depreciation on Clover Bar Energy Centre as all three units were operational in the nine months ended September 30, 2010 whereas only one unit was operational throughout the corresponding period in 2009 and another unit commenced operations in September 2009. In addition, depreciation expense for the second quarter of 2010 included a write-down of information technology assets.

Income taxes (reductions)

Income taxes for the three and nine months ended September 30, 2010 were higher than for the corresponding periods in 2009 primarily due to the recognition in the third quarter of 2010 of an $11 million future income tax liability relating to the review of strategic alternatives regarding the Company's investment in CPILP. Since it was no longer apparent that the taxable temporary differences between the tax basis and accounting basis of the investment in CPILP would not reverse in the foreseeable future, the Company recognized the future income tax liability associated with these differences. In addition, an income tax expense of $4 million relating to the prior year was recorded in the third quarter of 2010, whereas an income tax recovery of $10 million was recorded in the third quarter of 2009 for the recognition of a net future income tax asset out-of-period adjustment associated with CPILP's interest in Primary Energy Recycling Holdings LLC. These increases in income tax expense were partly offset by the impact of lower earnings before income taxes in the three and nine months ended September 30, 2010 compared with the corresponding periods in 2009.

Non-controlling interests

The non-controlling interests in CPILP reflect approximately 69.7% of CPILP net income which was lower for the three and nine months ended September 30, 2010 than for the corresponding periods in 2009. The non-controlling interests in CPLP reflected approximately 72.2% of the net income from CPLP which was lower in the three and nine months ended September 30, 2010 than the corresponding periods in 2009. Non-controlling interests for the nine months ended September 30, 2010 also included 100% of the gain on sale of the Battle River PPA in the first quarter. The sale had no impact on the Company's net income as the Company's 27.8% share of the fair value of the Battle River PPA was recognized in the purchase price allocation for the Reorganization.

Income from CPLP included approximately 30.3% of the CPILP net income. Therefore the non-controlling interests in CPLP included approximately 21.9% (72.2% of 30.3%) of CPILP net income.

Non-GAAP Financial Measures

The Company uses (i) gross margin, (ii) operating margin, (iii) funds from operations, (iv) funds from operations excluding non-controlling interests in CPILP, (v) normalized net income and (vi) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to Canadian GAAP and do not have standardized meanings prescribed by Canadian GAAP, 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 Canadian GAAP. Rather, these measures are provided to complement Canadian GAAP measures in the analysis of the Company's results of operations from management's perspective.

Gross margin and operating margin

Capital Power uses gross margin and operating margin to measure the operating performance of plants and groups of plants from period to period. A reconciliation of gross margin and operating margin to net income is as follows:

(unaudited, $millions)	Three months ended		Nine months ended	
	Sept 30, 2010	Sept 30, 2009	Sept 30, 2010	Sept 30, 2009
Revenues	$ 508	$ 511	$ 1,320	$1,661
Energy purchases and fuel	279	293	755	994
Gross margin	**229**	**218**	**565**	**667**
Operations, maintenance, direct administration and property taxes	53	49	167	166
Operating margin	**176**	**169**	**398**	**501**
Indirect administration	38	27	95	96
Depreciation, amortization and asset retirement accretion	48	44	146	135
Foreign exchange losses	1	3	-	5
Gain on sale of power syndicate agreement	-	-	(28)	(30)
Net financing expenses	25	17	62	60
Income taxes (recovery)	17	(2)	10	1
Non-controlling interests				
- CPLP	30	44	79	159
- CPILP	7	20	12	26
- Preferred share dividends paid by CPI Preferred Equity Ltd.[1]	3	2	10	5
Net income	**$ 7**	**$ 14**	**$ 12**	**$ 44**

(1) CPI Preferred Equity Ltd. is a subsidiary of CPILP.

Management considers operating margin to be representative of plant performance as it excludes corporate administration and business development expenses (indirect administration). The presentation of the pro forma consolidated information for the nine months ended September 30, 2009 conforms to the presentation adopted for the nine months ended September 30, 2010.

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 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. 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 provided by operating activities is as follows:

(unaudited, $millions)	Three months ended				
	Sept 30, 2010	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Funds from operations excluding non-controlling interests in CPILP	**$ 86**	**$ 34**	**$ 87**	**$ 49**	**$ 70**
Funds from operations due to non-controlling interests in CPILP	20	19	25	22	23
Funds from operations	106	53	112	71	93
Change in non-cash operating working capital	20	(22)	18	50	(40)
Cash provided by operating activities	**$ 126**	**$ 31**	**$ 130**	**$ 121**	**$ 53**

Normalized net income 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 net income according to Canadian GAAP adjusted for items that are not reflective of performance in the period such as fair value changes, impairments, unusual tax adjustments and gains or losses on disposal of assets or on unusual contracts. A reconciliation of net income (loss) to normalized net income, and earnings per share to normalized earnings per share is as follows:

(unaudited, $millions except earnings (loss) per share)	Three months ended				
	Sept 30, 2010	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Earnings (loss) per share	**$ 0.32**	**$ (0.37)**	**$ 0.60**	**$ 0.33**	**0.64**
Net income (loss)	**7**	**(8)**	**13**	**7**	**14**
Adjustments					
Unrealized changes in fair value of CPLP's derivative instruments and natural gas held for trading	(1)	7	-	(5)	(3)
Unrealized changes in fair value of CPILP's derivative instruments	-	1	-	(1)	(1)
Venture capital investment write-down	-	-	-	1	-
Obligation to EPCOR for Rossdale plant	2	-	-	-	-
Income tax adjustments	4	1	(1)	2	(1)
	5	9	(1)	(3)	(5)
Normalized net income	**12**	**1**	**12**	**4**	**9**
Normalized earnings per share	**$ 0.55**	**$ 0.05**	**$ 0.55**	**$ 0.18**	**$ 0.42**

Balance Sheet

The significant changes in the Consolidated Balance Sheets from December 31, 2009 to September 30, 2010 were as follows:

(unaudited, $millions)	Increase (decrease)	Explanation of increase (decrease)
Accounts receivable and income taxes recoverable	(77)	Primarily lower receivables from EPCOR for RRT energy supply, lower generation sales receivable from the Alberta Electric System Operator resulting from lower power prices, and decrease in income tax recoverable.
Property, plant and equipment	155	Capital expenditures partly offset by depreciation and amortization.
Power purchase arrangements	(44)	Primarily amortization.
Net derivative instruments assets	(77)	Primarily decreases in the fair value of derivative instrument natural gas, forward bond sale and foreign exchange contracts.
Accounts payable and accrued liabilities [1]	(72)	Primarily lower accruals for energy purchases resulting from lower customer energy consumption and lower power prices in September 2010 compared with December 2009.
Long-term debt (including current portion)	54	Primarily net drawings on CPLP's and CPILP's credit facilities.
Net future income tax liabilities	(23)	Primarily due to the future income tax impact of changes in the fair value of derivative contracts, partly offset by the future income tax liability relating to the review of strategic alternatives for the Company's investment in CPILP.
Non-controlling interests[1]	(26)	Non-controlling interests' share of CPLP and CPILP distributions and CPILP's other comprehensive loss, partly offset by non-controlling interests' share of CPLP and CPILP net income, CPLP other comprehensive income and CPILP unit issue.
Shareholders' equity	(10)	Common share dividends and other comprehensive loss, partly offset by net income.

(1) Accrued liabilities and non-controlling interests for December 31, 2009 have been recast to reflect the accrual of $18 million of distributions to non-controlling interests that were declared in the fourth quarter of 2009.

Liquidity and Capital Resources

Cash inflows (outflows)			
(unaudited, $millions)	Period ended September 30, 2010		
	Three months	Nine months	Explanation
Cash from Operating Activities	$ 126	$ 287	See Funds from Operations
Investing	(96)	(237)	Capital expenditures, primarily for property plant and equipment, partly offset by proceeds on the sale of the final interest in the Battle River PPA in January 2010.
Financing	(56)	(39)	Net debt repayments to EPCOR, distributions to non-controlling interests and dividends paid to common shareholders, partly offset by net drawings under CPLP's credit facilities.

On September 30, 2010 CPLP had $1,220 million of credit facilities, of which $709 million remained available, and CPILP had credit facilities of approximately $366 million, of which $289 million remained available. In addition, Capital Power Corporation had an undrawn bank line of credit of $5 million. In the second quarter of 2010, $1,200 million of CPLP's credit facilities were extended to July 2013 and by the end of the third quarter of 2010 CPILP had extended all three of its credit facilities to 2012.

In June 2010, CPLP made the following debt repayments to EPCOR: $200 million of 6.95% debt and $45 million of 9% debt. In the nine months ended September 30, 2010 CPLP made a net draw of $316 million on its credit facilities, primarily to finance the debt repayments in June, and to fund capital expenditures.

In the nine months ended September 30, 2010, CPILP made a net repayment of $1 million on amounts drawn under its revolving credit facilities. CPILP's outstanding long-term debt also reflects a decrease of $9 million in the first nine months of 2010 for foreign exchange on the translation of its U.S. dollar denominated debt.

On September 30, 2010, CPLP had $416 million of long-term debt and $95 million of letters of credit outstanding, and CPILP had $77 million of long-term debt and less than $1 million of letters of credit outstanding, under their respective credit facilities.

CPLP has received a corporate credit rating of BBB from S&P and a long-term debt credit rating of BBB from DBRS. 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. 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)	2010		Total project		
	Nine months ended Sept 30	Full year estimate[1]	Incurred to Sept 30, 2010[2]	Total cost estimate[1]	Target or actual completion date
CPLP					
Keephills 3	$ 178	$ 229	$ 852	$ 955	2nd quarter 2011
Quality Wind and Port Dover & Nanticoke	35	51	35	795	2nd quarter 2013 and 4th quarter 2012
Other	44	65			
Total CPLP	257	345			
CPILP					
Oxnard turbine replacement	14	16	19	21	4th quarter 2010
North Carolina plants enhancement	9	17	88	96	4th quarter 2010
Other	5	6			
Total CPILP	28	39			
Total capital expenditures	285	384			

(1) Capital expenditures to be incurred over the life of the project and in the twelve months ended December 31, 2010 are based on management's estimates.

(2) Total project capital expenditures incurred to September 30, 2010 reflect capital expenditures since the inception of the project.

Construction of Keephills 3 remains on target to the revised project cost forecast as discussed in the 2009 annual MD&A, and on schedule.

CPILP completed the enhancements to the second unit at Southport in April 2010 and expects to complete the material handling improvements at Southport by the end of 2010. CPILP completed the repowering of the natural gas turbine at Oxnard in the second quarter of 2010 and plans to invest in additional capital spares for the plant in the fourth quarter of 2010.

The Company's capital expenditures included in "Other" in the table above are primarily for the improvement of existing facilities and for environmental offsets.

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 last three months of 2010, excluding CPILP's cash requirements, are expected to include approximately $205 million plus closing costs for the acquisition of Island Generation on October 19, 2010, $88 million for capital expenditures, $18 million for CPLP distributions to EPCOR paid on October 29, 2010 and $7 million for Capital Power's quarterly dividends paid on October 29, 2010. The current portion of long-term debt on the balance sheet is primarily comprised of $33 million payable to EPCOR in June 2011.

The acquisition of Island Generation on October 19, 2010 was funded by a drawdown on CPLP's existing bank credit facilities. Subject to market conditions, Capital Power expects to permanently finance the acquisition with a combination of debt and equity. The Company expects to fund the construction of the Quality Wind and Port Dover & Nanticoke 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%.

In the second quarter of 2010, CPLP entered into two $100 million forward bond sale transactions for the purpose of hedging a portion of the exposure to interest rate risk on potential future borrowings. These forward contracts expire on March 1, 2011.

In April 2010, the Company filed two short form base shelf prospectuses which, market conditions permitting, provide 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. Pursuant to one of 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. If and when EPCOR exchanges its exchangeable partnership units of CPLP for common shares of the Company, they may sell their common shares under the base shelf prospectus as a secondary offering. Pursuant to the other short form base shelf prospectus, CPLP may raise up to $1 billion by issuing medium term notes with maturities of not less than one year. 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 last three months of 2010 are expected to include approximately $11 million for capital expenditures, approximately $24 million for distributions subject to approval by the CPILP Board of Directors and approximately $3 million for preferred share dividends of a subsidiary company subject to the approval of the Board of Directors of the subsidiary company. The estimate for CPILP distributions includes $8 million distributed on October 22, 2010. The amount of distributions will vary depending on the number of unitholders who opt under CPILP's distribution reinvestment program to accumulate additional units in lieu of cash distributions. If CPILP's total cash requirements for the balance of 2010 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.

In July 2010, CPILP filed a short form base shelf prospectus which, market conditions permitting, provides the partnership 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. Pursuant to the prospectus, CPILP may offer and sell limited partnership units, debt securities or subscription receipts exchangeable for partnership units or debt securities of the partnership, at an aggregate amount of up to $600 million. This base shelf prospectus expires in August 2012 and replaces CPILP's $1 billion shelf prospectus which would have expired in August 2010.

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

CPLP entered into a purchase and sale agreement for its acquisition of Island Generation which closed on October 19, 2010, as described under Subsequent Event.

During the second quarter of 2010, the Company's Port Dover & Nanticoke Wind Project was selected by the Ontario Power Authority for the award of a contract to sell power. The Company will commence construction of the project upon receipt of regulatory approvals, and commercial operation is expected to commence in the fourth quarter of 2012. See Capital Expenditures under Liquidity and Capital Resources.

During the second quarter of 2010, the Company and BC Hydro signed a PPA for the sale of power from the Company's Quality Wind Project. The Company will commence construction of the project upon receipt of regulatory approvals, and commercial operation is expected to commence no later than the spring of 2013. See Capital Expenditures under Liquidity and Capital Resources.

The Rossdale plant which is owned by EPCOR, was taken out of service in January 2009 and is to be decommissioned. Certain structures at the plant site were designated as Provincial Historical Resources by the Province of Alberta and are thereby legally protected from demolition. These structures, and additional structures at the plant site, are also on the City of Edmonton's Register of Historic Resources. CPLP has an obligation to EPCOR to share in some of the costs for ongoing operations and maintenance of the Rossdale plant and related assets. The loss of $7 million, representing the fair value of the obligation, was recognized in the third quarter of 2010.

The Company estimated the fair value of the obligation to EPCOR using a discounted cash flow approach based on an appropriate discount factor adjusted for the Company's credit risk. The anticipated future payments consisted primarily of operation and maintenance of the buildings that are not expected to be demolished, and a roof replacement. The cost estimates were primarily based on information provided by EPCOR including historical trends for the operations and maintenance and an independent engineering study for the roof replacement. The operation and maintenance cost estimates assumed a general inflation factor of 1.7%. Based on information from EPCOR relating to the decommissioning costs, the Company assumed that there will be no requirement under the terms of the agreement for it to make payments for decommissioning costs. The estimate of the Company's liability to EPCOR for the Rossdale assets could change if the timing of and actual costs for operations, maintenance and roof replacement differ from the Company's estimates or if additional capital maintenance is required.

There were no other changes to the Company's purchase obligations, commitments or contingencies during the third quarter of 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, 2009 MD&A, filed on SEDAR at www.sedar.com.

Off-balance Sheet Arrangements

As at September 30, 2010, the Company had no off-balance sheet arrangements.

Related Party Transactions

EPCOR, including its subsidiaries and its sole shareholder, The City of Edmonton, is the only related party with which the Company had material transactions in the nine months ended September 30, 2010. As part of the Reorganization in July 2009, EPCOR acquired 56.625 million exchangeable limited partnership units of CPLP, and 56.625 million accompanying special voting shares and one special limited voting share of the capital of Capital Power. At September 30, 2010, these partnership units and shares remained outstanding to EPCOR.

The Company's long-term debt payable to EPCOR, which was also issued in connection with the Reorganization, was $621 million at September 30, 2010. The interest incurred on this debt was $11 million and $40 million for the three and nine months ended September 30, 2010, respectively, of which $10 million and $32 million, respectively were capitalized as property, plant and equipment for construction work in progress over the corresponding periods. The remainder was included in net financing expense.

The Company's revenues for power sold to EPCOR for resale to its customers were $108 million and $297 million for the three and nine months ended September 30, 2010, respectively. The Company's purchases of distribution and transmission services from EPCOR were $9 million and $22 million for the three and nine months ended September 30, 2010, respectively. The Company also 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. 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.

The balances outstanding at September 30, 2010 resulting from transactions with EPCOR including the obligation for the operations and maintenance costs for the Rossdale plant and assets as described under Contractual Obligations, were as follows:

(unaudited, $ millions)	September 30, 2010
Balance sheet	
Accounts receivable	$ 35
Other assets	7
Property, plant and equipment	32
Accounts payable and accrued interest on debt	18
Other non-current liabilities	3

Business Risks

Canadian Federal Government Proposed Emission Regulation for Coal-Fired Generation

On June 23, 2010, the Canadian Environment Minister announced the Government of Canada's plan for new greenhouse gas (GHG) emission regulation for coal-fired electricity generation units. The proposed plan will apply a new GHG emissions performance standard to new coal-fired electricity generation units and those coal-fired units that have reached the end of their economic life. The purpose of the regulation is to ensure that conventional coal-fired electricity generation is phased out in an orderly manner and replaced with lower GHG emission power generation.

Very limited details are available but it is expected that the economic life will be set at 45 years with some exceptions to avoid stranding recent investments in older facilities. New performance standards will likely be similar to a natural gas combined cycle unit. Existing facilities that will be exempt from the regulation until they reach the end of their economic useful life are expected to be those that have commercial operation dates prior to January 1, 2012. Clarity regarding the draft regulations will be provided when they are published in the Canada Gazette which is expected to occur in early 2011, with final regulations expected later that year. Because the proposed regulations allow coal-fired generation assets to operate for their economic life and no additional charges for GHG emissions are anticipated, the regulations provide some certainty and are expected to be favourable to Capital Power's Genesee units and Keephills 3.

It is not clear whether the proposed federal GHG emission regulations will replace the Alberta Specified Gas Emitters Regulations (SGER). The current SGER will expire in 2014. If this date is extended then the Company's Alberta facilities may face continued charges under the SGER, which have historically been approximately $5 million per year. Currently there is insufficient information to reasonably predict what action the Alberta Government will take in respect of the SGER.

Apart from the Canadian Environment Minister's announcement, there have been no material changes in the nine months ended September 30, 2010 to the Company's business and operational risks as provided in the Company's December 31, 2009 MD&A. New risk policies and VaR statistical confidence interval were implemented in the first quarter of 2010, as discussed in the Company's March 31, 2010 MD&A.

Future Accounting Changes

International Financial Reporting Standards

In February 2008, the CICA confirmed that Canadian reporting issuers will be required to report under International Financial Reporting Standards (IFRS) effective January 1, 2011, including comparative figures for the prior year.

In January 2008, EPCOR established a core team to develop a plan which would result in the first interim report for 2011 being in compliance with IFRS. In July 2009, Capital Power organized its own IFRS team to work in conjunction with the EPCOR core team to continue with the plan and implement IFRS in Capital Power in time to meet the 2011 reporting requirements. The terms of the services to be provided by EPCOR to Capital Power for IFRS support are outlined in the Services Agreement by and between Capital Power and EPCOR.

The diagnostic phase of the project was completed in April 2008. For each international standard, EPCOR identified the primary differences from Canadian GAAP and made an initial assessment of the impact of the required changes for the purpose of prioritizing and assigning resources. The assessments were subsequently reviewed from a Capital Power perspective. The following standards are likely to have a significant impact on Capital Power:

International Financial Reporting Standard
IFRS 3 Business Combinations
IAS 16 Property, Plant and Equipment
IAS 37 Provisions, Contingent Liabilities and Contingent Assets
IAS 36 Impairment of Assets
IAS 17 Leases
IAS 31 Interests in Joint Ventures
IFRS 7, IAS 32, IAS 39 Financial Instruments
IAS 21 The Effects of Changes in Foreign Exchange Rates
IAS 12 Income Taxes

The information obtained from the diagnostic phase was used to develop a detailed plan for convergence and implementation. The convergence and implementation work has five key sections: Financial Statement Adjustments, Financial Statements, Systems Updates, Policies and Internal Controls, and Training.

Financial Statement Adjustments

For each international standard, the Company will determine the quantitative impacts to the financial statements, system requirements, accounting policy decisions, and changes to internal controls and business policies. The initial accounting policy decisions will be brought forward to the Audit Committee for their information as each standard is addressed. However, final accounting policy decisions for all standards in effect at the end of 2009 will be made in the fourth quarter of 2010, as they should not be determined in isolation of other policy decisions. Policy decisions for any new or amended standards issued in 2010 will be made in conjunction with the Company's analysis of those standards in 2010.

The more significant impacts of IFRS on the Company are expected to be:

- IFRS 3 – Business Combinations requires non-controlling interests to be recognized at fair value on acquisition, or at the non-controlling interests' share of the amounts recognized for the acquisition excluding goodwill. Under Canadian GAAP, non-controlling interests are initially recognized at amounts based on the carrying amounts in the acquired entity's financial statements. Under IFRS 1 – First Time Adoption of International Financial Reporting Standards an entity may elect not to apply IFRS 3 retrospectively. The Company plans to take the exemption and not restate the transactions related to the Reorganization. As the Reorganization was the Company's only business combination to date, IFRS 3 will not impact the Company's financial statements upon transition to IFRS. See Business Combinations, Consolidations and Non-Controlling Interests under the next section of Future Accounting Changes.
- Property, plant and equipment (PP&E) will be primarily impacted by IAS 16 – Property, Plant and Equipment and IAS 23 – Borrowing Costs. Unlike Canadian GAAP, IFRS does not allow certain costs related to the construction of PP&E, such as training costs, overheads and borrowing costs in excess of the entity's actual cost of debt, to be capitalized. As most of the assets were acquired as part of the July 2009 Reorganization, the impact of retrospectively adopting IAS 16 will not be significant.

  Accounting for the components of PP&E is required at a more detailed level under IFRS than under Canadian GAAP. IFRS require a separate component for assets with a distinct depreciation method or rate of deprecation. The Company has completed its analysis of its operations and has concluded on the appropriate level of componentization.

  The Company expects that on transition to IFRS, PP&E will decrease with an offsetting decrease to retained earnings. As a result of componentization, depreciation expense is expected to be higher than under Canadian GAAP. Quantification of these impacts will be presented to the Audit Committee in November 2010.
- IAS 37 – Provisions, Contingent Liabilities and Contingent Assets requires asset retirement obligations to be measured at management's best estimate of the costs of decommissioning assets whereas Canadian GAAP requires such obligations to be measured at the cost of using third party services for decommissioning. IAS 37 also requires the obligation to be discounted at a risk free rate, rather than the

credit adjusted risk free rate which is the case under Canadian GAAP. On transition, the Company expects that its PP&E and asset retirement obligation will increase and retained earnings will decrease. Quantification of these impacts will be presented to the Audit Committee in November 2010. The Company expects that on an ongoing basis, finance expense for the accretion of the liability and depreciation will be higher as a result of the increased obligation.

- IAS 36 – Impairment of Assets requires a one-step approach using discounted cash flow techniques for asset impairment testing and measurement. Canadian GAAP's two-step approach requires the application of discounted cash flow techniques to measure the impairment amount, but only after the use of undiscounted cash flow analysis has indicated the existence of an impairment. The adoption of IAS 36 may result in more frequent asset write downs since the carrying values of assets which are supported by undiscounted future 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 under IFRS if the circumstances which led to the impairment change.

  IAS 36 also requires impairment testing to be applied at a cash-generating unit level, which for Capital Power will likely be by plant or plant category. In addition, goodwill must be allocated to cash-generating units for impairment testing purposes. Under Canadian GAAP goodwill is not allocated to plants. Accordingly, the transition to IAS 36 increases the likelihood of a goodwill write down. The Company expects to have quantified the impact of IAS 36 by the end of 2010.

- IAS 17 – Leases was assessed primarily in the context of the Company's power purchase arrangements (PPAs). The Company has concluded its assessments of its PPAs and anticipates that only the Kingsbridge PPA will be impacted by IFRS and will be accounted for as a capital lease. The Company expects that on transition PP&E will decrease, finance lease receivable will increase and retained earnings will decrease. Quantification of these impacts will be presented to the Audit Committee in November 2010. On a go forward basis, the Company expects that a portion of what it currently presents as revenue will be presented as financing income.

- IAS 31 – Interests in Joint Ventures sets out the requirements for the accounting of joint ventures. This standard is expected to be replaced in the fourth quarter of 2010. The Company has reviewed its arrangements to the current standard and does not anticipate any change in accounting for its current arrangements.

- IFRS 1 – First Time Adoption of IFRS provides first time adopters with a number of elections, exempting them from retrospectively adopting certain IFRS. The following elections are relevant to Capital Power:

  An entity may deem the cost of an asset at the date of transition to be its fair value at that date. This election is available on an asset by asset basis.

  An entity may select any date prior to the transition date and elect to not apply IFRS 3 Business Combinations retrospectively to business combinations occurring prior to that date. The Company plans to take this election.

  On transition, an entity may elect to deem any balance for cumulative translation amounts to be zero and to reclassify the previous balance to retained earnings with no impact on the income statement.

  On transition, an entity is not required to reassess its determination of a contract as a lease. An entity may also choose to determine whether an arrangement existing at the date of transition contains a lease on the basis of facts and circumstances existing at that date, rather than at the date of inception of the lease.

  An entity may apply a simplified calculation for the restatement of decommissioning liabilities and associated property, plant and equipment and accumulated depreciation.

  An entity may elect to recognize all cumulative actuarial gains and losses relating to employee benefits at the date of transition.

  Capital Power has not made any decisions or recommendations with respect to any of the elections other than the election relating to Business Combinations.

Capital Power anticipates completing the quantification of the opening financial statement adjustments resulting from the application of all currently effective IFRS, including financial instruments, foreign exchange and income taxes, in the fourth quarter of 2010. An IFRS session for the Audit Committee has been scheduled for the fourth quarter of 2010 at which time transition adjustments and financial statements will be presented. All accounting policy changes and elections will also be brought forward for approval at this time.

As the project progresses, the timing of the completion of certain items may be impacted by changes to the standards and changes in priorities resulting from external factors such as discussions with stakeholders. However, the Company believes the project has sufficient resources to meet the overall project timeline.

Financial Statements

There are a number of international standards which relate to financial statement presentation. Draft financial statements highlighting the disclosure and presentation requirements were presented to the Audit Committee in March 2010. The development of the financial statement presentation will evolve throughout the project as the impacts of implementing the various standards are quantified.

The Company has identified those areas requiring additional disclosure and has started developing processes to capture the additional information.

Systems Updates

Systems must be able to capture 2010 financial information under both the prevailing Canadian GAAP and IFRS to allow comparative reporting in 2011. The Company completed its system updates in the third quarter of 2009 based on system requirements identified during the project's planning phase in 2008. The Company's parallel general ledgers and fixed asset systems have been implemented which allow both IFRS and Canadian GAAP information to be captured. The processes and internal controls related to the capture and reporting of IFRS information are similar to those for Canadian GAAP. Both systems have been operational since the third quarter of 2009.

Policies and Internal Controls

In the determination of the financial statement adjustments, requirements for changes to the Company's policies and internal controls will be identified and documented. Based on the project's progress to date, the Company has not identified any requirements for significant changes to processes or controls. As there may be factors other than IFRS impacting policies and internal controls, the formal documentation and approval of revised policies and internal controls will occur in the fourth quarter of 2010.

The impact of IFRS on certain agreements, such as debt, shareholder and compensation agreements, has also been included in the plan. Assessments of most agreements have been completed and the Company has not identified any provisions within the agreements which would be negatively impacted by the differences between IFRS and Canadian GAAP identified to date. The impact on the agreements will continue to be monitored as additional IFRS and Canadian GAAP differences are quantified.

The Company's investor relations department will work with the IFRS team in the fourth quarter of 2010 to prepare information for the investor analysts.

Training

The Company recognizes that training at all levels of the Company is essential to a successful conversion and integration. Accounting staff have attended four training sessions with more planned to occur throughout the conversion process. A training session for the Audit Committee occurred in March 2010 and another is scheduled for November 2010. The Audit Committee continues to receive regular updates throughout 2010.

Business Combinations, Consolidated Financial Statements and Non-controlling Interests

In January 2009, the CICA issued Handbook Sections 1582 – Business Combinations, 1601 – Consolidated Financial Statements and 1602 – Non-controlling Interests replacing Sections 1581 – Business Combinations and 1600 Consolidated Financial Statements. The new sections are equivalent to the provisions of IFRS 3 – Business Combinations and IAS 27 – Consolidated and Separate Financial Statements.

The new sections will apply to Capital Power on a prospective basis commencing January 1, 2011; although the sections allow earlier adoption as of the beginning of a fiscal year provided all three sections are adopted at the same time. In 2011, the Company will be required to show comparative information for any business combinations completed during 2010 measured and presented in accordance with IFRS 3 and IAS 27.

Accordingly, the Company may choose to adopt the new Sections as of the beginning of 2010, including the application of the provisions of Section 1582 to the acquisition of Island Generation to minimize the effect of making the transition to IFRS. The Company continues to assess whether it will early adopt the new sections as of January 1, 2010.

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, long-lived assets, asset retirement obligations, income taxes, leases or arrangements containing a lease, foreign currency translation and the consolidation of CPLP and CPILP.

As the Company is in the early stages of recovering business interruption insurance proceeds for the outage at Clover Bar Energy Centre Unit 2, the actual recovery could be higher or lower than the estimated $8 million that was recorded in the third quarter of 2010. The estimate is meant to represent income that would have been earned after the first 45 days of the outage, in accordance with the terms of the Company's insurance policy. The estimate of lost income was based on the actual operating results of Unit 3, a similar unit. However, the actual amount of recovery will depend on the outcomes of further analysis by the Company and positions to be taken by the insurer. The Company expects to file its claim in early November and that the claim will be settled by the end of the first half of 2011.

See Contractual Obligations for a discussion of the Company's estimate of the obligation to EPCOR for operation and maintenance costs for the Rossdale plant and assets.

For further information on the Company's accounting policies and estimates, refer to the Company's December 31, 2009 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 Sept 30, 2010	$ (50)	$ 53	$ 22	$ (11)	$ 14

At September 30, 2010, the fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of $50 million which primarily reflected the impact of decreased future prices for natural gas relative to natural gas supply contract prices.

At September 30, 2010 the fair value of energy derivative instruments not designated as hedges for accounting purposes was a net asset of $53 million, which primarily reflected the impact of changes in the forward Alberta power prices on the Alberta power portfolio.

At September 30, 2010, the fair value of the Company's forward foreign currency contracts was a net derivative instrument asset of $22 million, which primarily reflected the impact of strengthening future prices for the Canadian dollar relative to the U.S. dollar on forward foreign exchange sales contracts used to hedge U.S. dollar denominated revenues. As at September 30, 2010, $364 million (US$323 million) or approximately 96% of expected future net U.S. dollar cash flows from CPILP's U.S. plants for 2010 to 2016 were economically hedged at a weighted average exchange rate of $1.13 to US$1.00. As at September 30, 2010, $9 million (US$8 million) or approximately 92% of expected future net U.S. dollar cash flows for CPLP capital expenditure commitments for 2010 and 2011 were economically hedged at a weighted average exchange rate of $1.08 to US$1.00.

At September 30, 2010, the fair value of the Company's forward bond sale contracts was a net derivative instrument liability of $11 million. These contracts were entered into in the second quarter of 2010 to hedge exposure to interest rate risk on potential future debt issues. The unrealized changes in the fair value of these contracts for the second and third quarters of 2010 were recognized in financing expenses, as discussed under Consolidated Expenses.

For the three and nine months ended September 30, 2010, losses net of income taxes on derivative instruments designated as cash flow hedges, of $11 million and $29 million respectively, were recorded in other comprehensive income for the effective portion of cash flow hedges. Realized losses, net of income taxes, for the three and nine months ended September 30, 2010 of $16 million and $5 million respectively, were reclassified to energy purchases and revenues as appropriate. For the three and nine months ended September 30, 2010, the change in the fair value of the ineffective portion of hedging derivatives recognized in the income statement, before non-controlling interests, was $2 million and $3 million, respectively.

Internal Control over Financial Reporting

There were no changes in the Company's internal controls over financial reporting that occurred during the nine months ended September 30, 2010 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

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.

Forward-looking information in this MD&A includes, among other things, information relating to: (i) expectations regarding the review of strategic alternatives for CPILP, its potential outcome, and the intention of Capital Power to support the review of strategic alternatives but not participate as a prospective buyer if a sale were to occur; (ii) expectations regarding the timing of the CPILP strategic review process and that during the review process CPILP will continue its business as usual, provide the same amount of monthly distributions to its unitholders and maintain the same proposition it offers today; (iii) Capital Power's intention to continue managing CPILP assets and seek growth opportunities that fit CPILP's strategy; (iv) expectations for the Company's and CPILP's sources of capital and use and availability of committed bank credit facilities and potential future borrowings; (v) the Company's and CPILP's cash requirements for 2010, including capital expenditures, distributions and dividends; (vi) expected funding of the Quality Wind and Port Dover & Nanticoke wind projects during construction and once completed while maintaining a leverage in the range of 40% - 50%; (vii) expectations regarding future financial strength and access to and terms of future financings; (viii) expectations regarding amount and timing of operating margin and cash provided by operating activities from Island Generation; (ix) expectations that Island Generation will be modestly and immediately accretive to earnings and cash flow; (x) expectations regarding the timing of filing and settlement of the business interruption claim for the outage of Clover Bar Energy Centre Unit 2; (xi) expectations regarding the amount and the ability to fully recover the lost income through the business interruption claim as a result of the inability to dispatch Unit 2 during the outage; (xii) expectations regarding timing of spending on Keephills 3; (xiii) expected total capital project costs as well as expected project completion dates; (xiv) expected timing and maintenance cost impact of the Genesee 3 scheduled maintenance outage and the Company's ability to rely on the Clover Bar Energy Centre units during the outage; (xv) expectations regarding ability to meet the plant availability target in 2010 in light of issues with Clover Bar Energy Centre Unit 2; (xvi) expectations about future income; (xvii) expected impacts of transition to IFRS, including potential early adoption of new accounting standards and expected IFRS project review completion dates and timing of presenting quantification of impacts to the Audit Committee; (xviii) expectations regarding the impact of delays in the finalization of new PPAs for the North Carolina facilities on CPILP's earnings and cash flows, and the timing of the NCUC's decision following arbitration relating to new PPAs; (xix) expectations regarding the Company's obligation and amount of the costs for ongoing operations and maintenance of EPCOR's Rossdale plant and assets; (xx) expectations regarding the impact on Capital Power of the plan for a new GHG emission regulation as announced by the Canadian Environment Minister in June 2010 and expectations with respect to additional charges for GHG emissions; (xxi) expectations regarding the economic life of, and new performance standards for, coal-fired electricity generation units pursuant to the proposed new GHG regulation, and regarding the applicability of exemptions from the proposed new GHG regulation; (xxii) expectations regarding the timing of the draft and final GHG regulations and the GHG regulations being brought into force; (xxiii) impact of proposed federal GHG emission regulations on SGER and consequential impact on the Company's Alberta facilities; (xxiv) expectations regarding the expiry or extension of the SGER; (xxv) expectations regarding BC Hydro's responsibility for the fuel supply to the Island Generation Facility; and (xxvi) expectations regarding financing of the Island Generation acquisition.

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; (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 including Island Generation; (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 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; and (xxii) accounting treatment for Island Generation.

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; (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 and investments including Island Generation; and (xvii) the tax attributes of and implications of any acquisitions. 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) expectations regarding capital expenditures in 2010 have been revised to reflect a change in the timing of spending on the Keephills 3 project; (ii) the expected timing of the completion of the material handling improvements at CPILP's Southport plant and the purchase of capital spares for CPILP's Oxnard plant have been revised from the third quarter of 2010 to the end of 2010; (iii) a change in the expected timing of the quantification of the impact of IAS 36, from the third quarter of 2010 to by the end of 2010; (iv) the expected timing of the replacement of standard IAS 31 has been revised from the third quarter of 2010 to the fourth quarter of 2010; and (v) a change in the expected timing of the preparation of IFRS information for the investor analysts from the third quarter of 2010 to the fourth quarter of 2010.

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				
	Sept 30, 2010	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Revenues(3)	508	313	499	497	511
Gross margin(1)	229	120	216	216	218
Operating margin(1)	176	55	167	154	169
Net income (loss)	7	(8)	13	7	14
Earnings (loss) per share	$ 0.32	$ (0.37)	$ 0.60	$ 0.33	$ 0.64
Fully diluted earnings (loss) per share(2)	$ 0.31	$ (0.37)	$ 0.60	$ 0.30	$ 0.59
Funds from operations(1)	106	53	112	71	93
Normalized earnings per share(1)	$ 0.55	$ 0.05	$ 0.55	$ 0.18	$ 0.42
Capital expenditures	74	133	78	127	108
Long-term debt including current portion	1,773	1,808	1,634	1,719	1,771
Total assets	5,005	5,015	4,952	5,036	4,918

(1) The consolidated financial information, except for gross margin, operating margin, funds from operations and normalized earnings per share, has been prepared in accordance with Canadian GAAP. See Non-GAAP 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 on a one-for-one basis) held by EPCOR.

(3) 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 margin, operating margin or net income and the presentation is consistent with subsequent periods.

Generation volume and plant availability information

(unaudited, GWh)	Three months ended				
Electricity generation[1]	Sept 30, 2010	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants					
Genesee 3	475	432	483	484	470
Joffre	67	93	41	73	89
Clover Bar Energy Centre 1, 2 and 3[2]	37	102	43	9	16
Taylor Coulee Chute	7	3	-	2	12
Clover Bar Landfill Gas	9	10	10	10	9
Weather Dancer	-	-	-	-	-
	595	640	577	578	596
Alberta contracted plants					
Genesee 1	841	780	813	618	837
Genesee 2	824	571	825	817	801
	1,665	1,351	1,638	1,435	1,638
Ontario and British Columbia contracted plants					
Kingsbridge 1	18	22	26	32	14
Miller Creek	46	35	7	14	47
Brown Lake	5	11	13	15	11
	69	68	46	61	72
Total plants excluding CPILP plants	**2,329**	**2,059**	**2,261**	**2,074**	**2,306**
CPILP plants	1,306	1,128	1,268	1,407	1,228
Total plants	**3,635**	**3,187**	**3,529**	**3,481**	**3,534**

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

(2) Clover Bar Energy Centre includes Units 1, 2 and 3 as of their commercial operation dates, March 10, 2008, September 1, 2009 and December 16, 2009, respectively.

(unaudited)	Three months ended				
Generation plant availability[1]	Sept 30, 2010	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants					
Genesee 3	99%	96%	100%	99%	97%
Joffre	98%	84%	100%	94%	96%
Clover Bar Energy Centre 1, 2 and 3[2]	63%	52%	72%	98%	96%
Taylor Coulee Chute	100%	90%	98%	66%	100%
Clover Bar Landfill Gas	92%	96%	96%	94%	90%
Weather Dancer	0%	0%	83%	0%	55%
	86%	76%	98%	97%	96%
Alberta contracted plants					
Genesee 1	100%	100%	99%	74%	100%
Genesee 2	97%	75%	99%	97%	95%
	99%	87%	99%	85%	97%
Ontario and British Columbia contracted plants					
Kingsbridge 1	99%	100%	99%	100%	99%
Miller Creek	96%	96%	37%	97%	88%
Brown Lake	93%	99%	97%	99%	97%
	97%	98%	71%	99%	94%
Average excluding CPILP plants[3]	**93%**	**83%**	**97%**	**92%**	**97%**
CPILP plants[3]	97%	90%	95%	92%	93%
Average all plants[3]	**95%**	**86%**	**96%**	**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) Clover Bar Energy Centre includes Units 1, 2 and 3 as of their commercial operation dates, March 10, 2008, September 1, 2009 and December 16, 2009, respectively.

(3) 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 2010 is 94%. In the third quarter of 2010, 93% was achieved for this performance measure, reflecting the outage at Clover Bar Energy Centre Unit 2 which was offline from March 8, 2010 through to September 22, 2010 for mechanical issues.

Results by plant category

(unaudited, $ millions)	Three months ended				
	Sept 30, 2010	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009[2]
Revenues					
Alberta commercial plants and portfolio optimization	$ 250	$ 197	$ 235	$ 248	$ 238
Alberta contracted plants	71	55	72	61	70
Ontario/British Columbia contracted plants	4	4	3	4	4
CPILP plants	130	116	139	130	123
Other portfolio activities	15	25	43	40	23
Inter-plant category transaction eliminations	(10)	(10)	(10)	(9)	(10)
	460	387	482	474	448
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading					
- CPLP	37	(55)	12	15	30
- CPILP	11	(19)	5	8	33
	48	(74)	17	23	63
	$ 508	**$ 313**	**$ 499**	**$ 497**	**$ 511**
Gross margin[1]					
Alberta commercial plants and portfolio optimization	72	$ 60	$ 65	$ 53	$ 50
Alberta contracted plants	57	43	59	48	58
Ontario/British Columbia contracted plants	4	4	3	4	4
CPILP plants	76	68	77	74	77
Other portfolio activities	9	8	15	12	8
Inter-plant category transaction eliminations	(9)	(9)	(9)	(9)	(8)
	209	174	210	182	189
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading					
- CPLP	14	(36)	9	26	16
- CPILP	6	(18)	(3)	8	13
	20	(54)	6	34	29
	$ 229	**$ 120**	**$ 216**	**$ 216**	**$ 218**
Operating margin[1]					
Alberta commercial plants and portfolio optimization	$ 59	$ 47	$ 55	$ 39	$ 41
Alberta contracted plants	48	19	46	27	47
Ontario/British Columbia contracted plants	3	2	2	3	3
CPILP plants	48	41	53	47	48
Other portfolio activities	1	-	5	4	2
Inter-plant category transaction eliminations	(3)	-	-	-	(1)
	156	109	161	120	140
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading					
- CPLP	14	(36)	9	26	16
- CPILP	6	(18)	(3)	8	13
	20	(54)	6	34	29
	$ 176	**$ 55**	**$ 167**	**$ 154**	**$ 169**

(1) The results by plant category, except for gross margin and operating margin, have been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

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

Factors impacting the 2010 third quarter results

The realized price for the Alberta commercial plants and portfolio in the third quarter of 2010 was $66/MWh which was $30/MWh higher than the average Alberta power price for the period. The favourable realized price was primarily a result of merchant trades of derivative sell contracts that settled in the period.

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 third quarter of 2010 and included in the results for Alberta commercial plants and portfolio.

The operating margin from other portfolio activities reflected realized losses on natural gas trading and few trading opportunities in the import and export power markets.

The unrealized changes in the fair value of CPLP's derivative instruments primarily reflected the impact of decreased Alberta forward power prices on the portfolio positions.

The unrealized changes in the fair value of CPILP's derivative instruments primarily reflected gains on foreign exchange contracts due to strengthening future prices for the Canadian dollar relative to the U.S. dollar.

Indirect administration expenses included $7 million for the recognition of the obligation to EPCOR for the operations and maintenance costs for the Rossdale plant and assets over the ten year period ending in 2019.

Financing expenses for the third quarter of 2010 included $7 million of unrealized losses for the decrease in the fair value of two forward bond sale contracts that were entered into in the second quarter of 2010.

Income taxes reflected the recognition of an $11 million future income tax liability relating to the investment in CPILP as a result of the strategic alternatives review.

Factors impacting results for the previous quarters

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

In the second quarter of 2010, the realized price for the Alberta commercial plants and portfolio was $66/MWh which was $15/MWh lower than the average Alberta power price for the period. High pricing and volatility of Alberta power spot prices resulted in higher than normal dispatch of the Alberta commercial peaking and mid-merit plants. The favourable impact of this increased generation on the operating margin was partly offset by the impact of lower operating margins from portfolio optimization strategies that were successful in the first quarter of 2010 and had an unfavourable impact in the second quarter. The operating margin for the Alberta contracted plants reflected $12 million of availability penalties and $13 million in maintenance costs related to the 21-day scheduled outage at Genesee 2. The unrealized changes in the fair value of CPLP's derivative instruments primarily reflected the impact of increased Alberta forward power prices on the portfolio positions. The unrealized changes in the fair value of CPILP's derivative instruments primarily reflected gains on foreign exchange contracts due to strengthening future prices for the Canadian dollar relative to the U.S. dollar, partly offset by losses on natural gas supply contracts due to decreases in forward natural gas prices.

In the first quarter of 2010, the realized price for the Alberta commercial plants and portfolio was $67/MWh which was $26/MWh higher than the average Alberta power price for the period. This favourable realized price was primarily a result of merchant trading of derivative sell contracts in the period.

In the fourth quarter of 2009, the planned outage at Genesee 1 resulted in availability penalty payments and approximately $10 million of maintenance costs. Unrealized gains for changes in the fair value of CPLP's derivative contracts in the fourth quarter of 2009 were the result of decreased forward Alberta power prices. Strengthening future prices for the Canadian dollar relative to the U.S. dollar resulted in an unrealized increase in the fair value of CPILP's foreign exchange contracts. Indirect administration expenses included an impairment loss of $4 million on a venture capital investment, an increase in information technology costs of $2 million and transition costs relating to the Reorganization. An income tax recovery that was recognized in the third quarter was reclassified and included in the acquisition of assets from EPCOR since it related to periods prior to July 1, 2009.

In the third quarter of 2009, the unrealized increase in the fair value of CPLP's derivative instruments was primarily due to the impact of decreased forward Alberta power prices on the portfolio. The unrealized increase in the fair value of CPILP's derivative instruments was primarily due to the impact of strengthening future prices for the Canadian dollar relative to the U.S. dollar on foreign exchange contracts. This was partly offset by a decrease in the fair value of CPILP's natural gas supply contracts for the period before they were designated as hedges for accounting purposes on July 31, 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					
	Sept 30, 2010	June 30, 2010	March 31, 2010	Dec 31, 2009	Sept 30, 2009	June 30, 2009
Share price						
High	$24.20	$23.39	$23.00	$21.78	$22.39	$23.00
Low	$21.75	$21.76	$20.97	$18.95	$19.50	$22.00
Close	$24.10	$22.14	$22.50	$21.37	$19.75	$22.35
Volume traded (millions)	2.4	4.4	7.6	6.5	12.1	5.8

As at October 29, 2010, the Company had 21.767 million common shares outstanding, 56.625 million special voting shares outstanding and one special limited voting share outstanding. The weighted average number of common shares outstanding on a diluted basis was 78.392 million for the three months ended September 30, 2010 and 21,756 million for the nine months ended September 30, 2010. All of the outstanding special voting shares and the outstanding special limited voting share are held indirectly by EPCOR.

As at October 29, 2010, CPLP had 21.750 million general partnership units outstanding, one common limited partnership unit outstanding and 56.625 million exchangeable limited partnership units outstanding, which are exchangeable for 56.625 million common shares of the Company. All of the outstanding general partnership units and the outstanding common limited partnership unit are held, indirectly, by the Company. All of the outstanding exchangeable limited partnership units are held indirectly by EPCOR.

As at October 29, 2010, CPILP had 55.6 million limited partnership units outstanding and 16.5 million of such units, representing 29.7% 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 continuous disclosure documents, is available on SEDAR at www.sedar.com.

CAPITAL POWER CORPORATION

Consolidated Statements of Income
(Unaudited, in millions of dollars except shares and per share amounts)

	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010
Revenues	$ 508	$ 511	$ 1,320
Energy purchases and fuel	279	293	755
	229	218	565
Operations, maintenance and direct administration	48	44	153
Indirect administration	38	27	95
Property taxes	5	5	14
Depreciation, amortization and asset retirement accretion	48	44	146
Foreign exchange losses	1	3	-
Gain on sale of power syndicate agreement (note 4)	-	-	(28)
Net financing expenses	25	17	62
	165	140	442
Income before income tax expense (recovery) and non-controlling interests	64	78	123
Income tax expense (recovery) (note 8)	17	(2)	10
Income before non-controlling interests	47	80	113
Non-controlling interests (note 7)	40	66	101
Net income	$ 7	$ 14	$ 12
Earnings per share			
Basic	$ 0.32	$ 0.64	$ 0.55
Diluted	0.31	0.59	0.55
Weighted average number of common shares outstanding (note 6)			
Basic	21,767,200	21,750,000	21,756,237
Diluted	78,392,200	78,375,000	21,756,237

See accompanying notes to interim consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Balance Sheets
(Unaudited, in millions of dollars)

	September 30, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 62	$ 52
Accounts receivable	223	275
Income taxes recoverable	4	29
Inventories	58	58
Prepaid expenses	12	8
Derivative instruments assets (note 9)	170	146
Future income tax assets (note 8)	2	2
Assets held for sale (note 4)	-	36
	531	606
Property, plant and equipment	3,397	3,242
Power purchase arrangements	484	528
Contract and customer rights and other intangible assets	189	184
Derivative instruments assets (note 9)	97	155
Future income tax assets (note 8)	60	61
Goodwill	141	140
Other assets	106	120
	$ 5,005	$ 5,036
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 267	$ 339
Other current liabilities	6	8
Derivative instruments liabilities (note 9)	139	108
Future income tax liabilities (note 8)	17	21
Current portion of long-term debt	34	247
	463	723
Long-term debt (note 5)	1,739	1,472
Derivative instruments liabilities (note 9)	114	102
Other non-current liabilities	115	109
Future income tax liabilities (note 8)	75	95
	2,506	2,501
Non-controlling interests (note 7)	2,020	2,046
Shareholders' equity:		
Share capital	477	477
Contributed surplus	3	2
Retained earnings (deficit)	(2)	7
Accumulated other comprehensive income	1	3
Retained earnings (deficit) and accumulated other comprehensive income	(1)	10
	479	489
Commitments (note 11)		
Subsequent events (note 11)		
	$ 5,005	$ 5,036

See accompanying notes to interim consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Statements of Shareholders' Equity
(Unaudited, in millions of dollars)

	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010
Share capital:			
Balance, beginning of period	$ 477	$ -	$ 477
Common shares issued	-	477	-
Balance, end of period	477	477	477
Contributed surplus:			
Balance, beginning of period	3	-	2
Stock-based compensation	-	-	1
Balance, end of period	3	-	3
Retained earnings (deficit):			
Balance, beginning of period	(2)	-	7
Net income	7	14	12
Common share dividends	(7)	-	(21)
Balance, end of period	(2)	14	(2)
Accumulated other comprehensive income:			
Balance, beginning of period	1	-	3
Other comprehensive income (loss)	-	3	(2)
Balance, end of period	1	3	1
Total shareholders' equity, end of period	$ 479	$ 494	$ 479

See accompanying notes to interim consolidated financial statements.

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010
Net income	$ 7	$ 14	$ 12
Other comprehensive income (loss), net of income taxes:			
Changes in gains and losses on derivative instruments designated as cash flow hedges[1]	(11)	8	(29)
Reclassification of losses on derivative instruments designated as cash flow hedges to net income[2]	16	21	5
Reclassification of ineffective portion of cash flow hedges to net income[4]	2	-	3
Unrealized loss in self-sustaining foreign operations[3]	(22)	(33)	(14)
Non-controlling interests[4] (note 7)	15	7	33
	-	3	(2)
Comprehensive income	$ 7	$ 17	$ 10

1 For the three and nine months ended September 30, 2010, net of income tax recoveries of $10 and $18, respectively. For the three months ended September 30, 2009, net of income tax expense of $1.

2 For the three and nine months ended September 30, 2010, net of reclassification of income tax recoveries of $2 and $1, respectively. For the three months ended September 30, 2009, net of reclassification of income tax recovery of $2.

3 For the three and nine months ended September 30, 2010, net of income tax expenses of $3 and $2, respectively. For the three months ended September 30, 2009 net of income tax expense of nil.

4 For the three and nine months ended September 30, 2010, net of income tax expense of nil. For the three months ended September 30, 2009, net of income tax expense of nil.

See accompanying notes to interim consolidated financial statements.

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2010	2009	Nine months ended September 30, 2010
Operating activities:			
Net income	$ 7	$ 14	$ 12
Adjustments to reconcile net income to cash flows from operating activities:			
Depreciation, amortization and asset retirement accretion	48	44	146
Gain on sale of power syndicate agreement (note 4)	-	-	(28)
Non-controlling interests in CPILP and CPLP (note 7)	37	64	91
Fair value changes on derivative instruments	(13)	(28)	37
Unrealized foreign exchange losses	2	3	2
Future income taxes	16	(3)	7
Other	9	(1)	4
	106	93	271
Change in non-cash operating working capital	20	(40)	16
	126	53	287
Investing activities:			
Property, plant and equipment and other assets	(74)	(108)	(285)
Business acquisition, net of acquired cash	-	(1,293)	-
Change in non-cash working capital	(18)	-	(18)
Proceeds on sale of power syndicate agreement (note 4)	-	-	64
Other	(4)	-	2
	(96)	(1,401)	(237)
Financing activities:			
Repayment of long-term debt	(21)	(41)	(267)
Proceeds from issue of long-term debt	-	1,001	335
Distributions to non-controlling interests (note 7)	(28)	-	(84)
Common share dividends paid	(7)	-	(21)
Issue of common shares	-	500	-
Share issue costs	-	(32)	-
Debt issue costs	-	(13)	(3)
Other	-	-	1
	(56)	1,415	(39)
Foreign exchange losses on cash held in a foreign currency	(1)	(3)	(1)
Increase (decrease) in cash and cash equivalents	(27)	64	10
Cash and cash equivalents, beginning of period	89	-	52
Cash and cash equivalents, end of period	$ 62	$ 64	$ 62
Supplementary cash flow information:			
Interest (paid) net of interest received	$ (28)	$ (18)	$ (78)
Net income taxes recovered	3	1	10

See accompanying notes to interim consolidated financial statements.

1. Basis of presentation:

These unaudited interim consolidated financial statements of Capital Power Corporation (the Company or Capital Power) have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) for interim financial statements and do not include all of the disclosures normally found in the Company's annual consolidated financial statements. These unaudited interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements for the six months ended December 31, 2009.

These financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent consolidated financial statements for the six months ended December 31, 2009.

The Company was incorporated on May 1, 2009, and did not have any results from operations or significant cash flows in the period from May 1 to June 30, 2009. Accordingly, the comparative statement of income, statement of shareholders' equity, statement of comprehensive income and statement of cash flows are presented only for the three months ended September 30, 2009.

2. Nature of operations:

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.

3. Measurement uncertainty:

In accordance with Canadian GAAP, the Company uses estimates in preparing its consolidated financial statements. Interim consolidated financial statements necessarily employ a greater use of estimates than the annual consolidated financial statements. In the opinion of management of the Company, these interim consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's accounting policies.

4. Sale of power syndicate agreement:

The Company's interest in the Battle River Power Syndicate Agreement (Battle River PSA) was disposed of on January 15, 2010 for proceeds of $64 million. The Company recognized a gain on disposal of $28 million less income taxes of $2 million in the first quarter of 2010. The Battle River PSA was previously acquired by the Company, effective July 1, 2009, as a part of the acquisition of assets from EPCOR Utilities Inc. At the acquisition date, the Company recognized fair value adjustments to the Battle River PSA asset for the Company's 27.75% share of the Battle River PSA gain on disposal. As a result, the impact on net income after non-controlling interests of the sale of the Battle River PSA in the nine months ended September 30, 2010 is nil.

5. Long-Term Debt:

Unsecured three-year credit facilities of $700 million are available to the Company's subsidiary, Capital Power LP (CPLP). At September 30, 2010, the Company had $416 million in bankers' acceptances outstanding under this facility (December 31, 2009 - $100 million).

(Unaudited, tabular amounts in millions of dollars)

6. Earnings per share:

	Three months ended September 30,					
	2010			2009		
	Common shares		Income	Common shares		Income
Amounts used in calculation of basic earnings per share	21,767,200	$	7	21,750,000	$	14
Effect of dilutive share purchase options [1]	-		-	-		-
Effect of exchangeable limited partnership units [2]	56,625,000		17	56,625,000		32
Amounts used in calculation of diluted earnings per share	78,392,200	$	24	78,375,000	$	46

1 For the three months ended September 30, 2010 and September 30, 2009, the share purchase options did not have a dilutive effect on earnings per share as the average market price of the Company's common shares was below the exercise price.

2 The exchangeable limited partnership units issued to EPCOR may be exchanged for common shares of Capital Power on a one-for-one basis. For the three months ended September 30, 2010 and September 30, 2009, the exchange of such units for common shares of the Company had a dilutive impact as the exchange would remove the non-controlling interest in net income related to CPLP of $30 million and $44 million, respectively. Additionally, the income tax provision of the Company would need to be adjusted to reflect the non-controlling interest's share of CPLP income taxes of approximately $13 million and $12 million for the three months ended September 30, 2010 and September 30, 2009, respectively.

	Nine months ended September 30, 2010		
	Common shares		Income
Amounts used in calculation of basic earnings per share	21,756,237	$	12
Effect of Dilutive share purchase options [1]	-		-
Effect of exchangeable limited partnership units [1]	-		-
Amounts used in calculation of diluted earnings per share	21,756,237	$	12

1 For the nine months ended September 30, 2010, the share purchase options and exchangeable limited partnership units issued to EPCOR were not included in the calculation of diluted earnings per share as they were anti-dilutive.

(Unaudited, tabular amounts in millions of dollars)

7. Non-controlling interests:

Results of operations which relate to non-controlling interests are as follows:

	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010
Non-controlling interests in Capital Power Income L.P. (CPILP)	$ 7	$ 20	$ 12
Non-controlling interests in CPLP	30	44	79
Preferred share dividends paid by subsidiary company	3	2	10
	$ 40	$ 66	$ 101

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

	September 30, 2010	December 31, 2009
Non-controlling interests in CPILP, beginning of period	$ 345	$ -
Non-controlling interests in CPILP in net assets acquired	-	383
Net income attributable to non-controlling interests	12	26
Other comprehensive loss attributable to non-controlling interests	(38)	(34)
Distributions to non-controlling interests	(50)	(33)
Issue of CPILP units to non-controlling interests	20	3
Non-controlling interests in CPILP, end of period	289	345
Non-controlling interests in CPLP, beginning of period	1,481	-
Non-controlling interests in CPLP in net assets acquired	-	130
Partnership units issued to non-controlling interests	-	1,302
Net income attributable to non-controlling interests	79	68
Other comprehensive income attributable to non-controlling interests	5	17
Distributions to non-controlling interests	(54)	(36)
Non-controlling interests in CPLP, end of period	1,511	1,481
Preferred shares issued by subsidiary companies, beginning of period	220	-
Preferred shares outstanding in acquired subsidiaries	-	122
Issue of preferred shares	-	98
Preferred shares issued by subsidiary companies, end of period	220	220
	$ 2,020	$ 2,046

(Unaudited, tabular amounts in millions of dollars)

8. Income taxes:

	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010
Future income tax expense (recovery)	$ 19	$ (2)	$ (2)
Current income tax expense (recovery)	(2)	-	12
	$ 17	$ (2)	$ 10

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

	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010
Income (loss) before income taxes and non-controlling interests	$ 64	$ 78	$ 123
Statutory income tax rates	28.0%	29.0%	28.0%
Income taxes at statutory rate	18	23	34
Increase (decrease) resulting from:			
Amounts previously not recognized on investment in subsidiaries	12	-	12
Taxable income attributable to non-controlling interests	(9)	(12)	(27)
Prior period tax adjustments	4	(10)	4
Non-taxable amounts	(4)	2	(7)
Change in valuation allowance	(4)	(4)	(1)
Adjustment for enacted changes in income tax laws and rates and other tax rate differences	(1)	(1)	(4)
Other	1	-	(1)
	$ 17	$ (2)	$ 10

(Unaudited, tabular amounts in millions of dollars)

8. Income taxes, continued:

The tax effects of temporary differences that give rise to significant components of the future income tax assets and future income tax liabilities are presented below:

	September 30, 2010	December 31, 2009
Property, plant and equipment – differences in net book value and tax bases	$ (112)	$ (102)
Losses carried forward	95	79
Power purchase arrangements	(22)	(27)
Asset retirement obligations	14	13
Cumulative eligible capital	12	12
Deferred income from partnerships	(9)	(19)
Derivative Instruments	17	(5)
Other	(25)	(4)
Net future income tax liabilities	$ (30)	$ (53)
Presented on the balance sheet as follows:		
Current assets	$ 2	$ 2
Non-current assets	60	61
Current liabilities	(17)	(21)
Non-current liabilities	(75)	(95)
	$ (30)	$ (53)

(Unaudited, tabular amounts in millions of dollars)

9. Derivative instruments and hedge accounting:

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

Derivative instruments assets and liabilities consist of the following:

	September 30, 2010				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 32	$ 131	$ 7	$ -	$ 170
Non-current	24	51	22	-	97
Derivative instruments liabilities:					
Current	(26)	(100)	(2)	(11)	(139)
Non-current	(80)	(29)	(5)	-	(114)
Net fair value	$ (50)	$ 53	$ 22	$ (11)	$ 14
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(3)			
Gigajoules of natural gas (millions)	40	6			
Foreign currency (U.S. dollars)			$ (315)		
Interest rate swaps				$ 200	
Range of contract terms in years	0.1 to 6.3	0.1 to 4.3	0.1 to 5.7	0.4	

(Unaudited, tabular amounts in millions of dollars)

9. Derivative instruments and hedge accounting, continued:

	December 31, 2009				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 15	$ 126	$ 5	$ -	$ 146
Non-current	32	97	26	-	155
Derivative instruments liabilities:					
Current	(23)	(83)	(2)	-	(108)
Non-current	(37)	(61)	(4)	-	(102)
Net fair value	$ (13)	$ 79	$ 25	$ -	$ 91
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(4)			
Gigajoules of natural gas (millions)	45	9			
Foreign currency (U.S. dollars)			$ (379)		
Interest rate swaps				$ -	
Range of contract terms in years	0.1 to 7.0	0.1 to 4.8	0.1 to 6.0		

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

	Three months ended September 30,			
	2010		2009	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (4)	$ (18)	$ 31	$ (22)
Energy non-hedges	9	(3)	(4)	-
Foreign exchange non-hedges	11	-	32	-
Interest rate non-hedges	(7)	-	-	-

	Nine months ended September 30, 2010	
	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (40)	$ (6)
Energy non-hedges	(25)	18
Foreign exchange non-hedges	(2)	4
Interest rate non-hedges	(11)	-

9. Derivative instruments and hedge accounting, continued:

Realized gains and losses relate only to financial derivative instruments. Gains and losses on non-financial derivative instruments settlements are recorded in energy revenues or energy purchases and fuel, as appropriate.

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity and natural gas prices. For the three and nine months ended September 30, 2010, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement, before non-controlling interests, were $2 million and $3 million, respectively. Net gains of $21 million, net of income taxes of $2 million, related to derivative instruments designated as cash-flow hedges, are expected to settle and be reclassified to net income over the next twelve months. The Company's cash flow hedges extend up to 2016.

10. Risk management:

Market risk

Commodity price risk

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

- The Company reduces its exposure to the volatility of commodity prices related to electricity sales by entering into offsetting contracts such as contracts-for-differences and firm price physical contracts for periods of varying duration.
- The Company enters into fixed-price energy sales contracts and power purchase arrangements which limit the exposure to electricity prices. The Company has entered into long-term tolling arrangements whereby variable changes linked to the price of natural gas and coal are assumed by the counterparty.
- When it is economically feasible, the Company purchases natural gas under long-term fixed-price supply contracts to reduce the exposure to fluctuating natural gas prices on its natural gas-fired generation plants and physical obligations arising from retail customers.
- The Company enters into back-to-back electricity and natural gas physical and financial contracts in order to lock in a margin.

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

The fair value of the Company's energy related derivatives at September 30, 2010 that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 9.

10. Risk management, continued:

Market risk, continued

Commodity price risk, continued

The Company employs specific volumetric limits and a Value-at-Risk (VaR) methodology to manage risk exposures to commodity prices on a consolidated basis. VaR measures the estimated potential loss in a portfolio of positions associated with the movement of a commodity price for a specified time or holding period and a given confidence level. Effective January 11, 2010, the Company has adopted a new risk management framework. Under this framework, Capital Power's current period VaR uses a statistical confidence interval of 99% over a five day holding period. This measure reflects a 1% probability that, over the five day period commencing with the point in time that the VaR is measured, the fair value of the overall commodity portfolio could decrease by an amount in excess of the VaR amount. The VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities and risk diversification by recognizing offsetting positions and correlations between products and markets. This technique makes use of historical data and makes an assessment of the market risk arising from possible future changes in commodity prices over the holding period.

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

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

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

The estimation of VaR takes into account positions from all wholly-owned subsidiaries and subsidiaries in which the Company has controlling interest, and reflects the Company's aggregate commodity positions from its trading and asset portfolios. Capital Power's Board of Directors has established methodology for the ongoing determination of Commodity Risk limits, under their risk management policy. Commodity risk is monitored and reported to the executive team on a daily basis. The portfolios are stress tested regularly to observe the effects of plausible scenarios taking into account historical maximum volatilities and maximum observed price movements. Based on the commodity portfolio as at September 30, 2010, there is a 99% probability that unfavorable daily market variations would not reduce the twelve month portfolio by more than $8 million.

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, floating rate short-term and long-term loans and obligations and interest rate derivatives. The Company is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. At September 30, 2010, the proportion of fixed rate debt was approximately 72% of total long-term debt outstanding (December 31, 2009 – 90%). The Company may also use derivative instruments to manage interest rate risk. At September 30, 2010, the Company held interest rate derivatives as disclosed in note 9.

(Unaudited, tabular amounts in millions of dollars)

10. Risk management, continued:

Market risk, continued

Interest rate risk, continued

Assuming that the amount and mix of fixed and floating rate loans, net debt, and interest rate derivatives remains unchanged from that held at September 30, 2010, a 100 basis point decrease or increase to interest rates would decrease or increase full year net income by $3 million and $2 million respectively and would have no direct impact on other comprehensive income.

The effect on net income does not consider the effect of an overall change in economic activity that would accompany such an increase or decrease in interest rates. There would be no impact on net income for debt and long-term loan arrangements issued and held by the Company at fixed interest rates.

Liquidity risk

As at September 30, 2010, the Company had undrawn and committed bank credit facilities, and operating lines of credit and demand facilities, totaling $1,003 million (December 31, 2009 - $1,294 million), of which $712 million (December 31, 2009 - $600 million) is committed for at least two years.

In addition to the facilities noted above, the Company has shelf prospectuses under which it may raise funds in the form of debt or capital. In the third quarter of 2010, the Company's subsidiary, CPILP, issued a Canadian shelf prospectus, which expires in August 2012, under which it may raise up to $600 million in partnership units, debt securities or subscription receipts. As at September 30, 2010, CPILP has not drawn on the shelf prospectus. In the first quarter of 2010, CPC issued a Canadian shelf prospectus, which expires in May 2012, under which it may raise up to $1 billion collectively in common shares of the Company and subscription receipts exchangeable for common shares and/or other securities of the Company. As at September 30, 2010, CPC has not drawn on the shelf prospectus. In the first quarter of 2010, the Company's subsidiary, CPLP, issued a Canadian shelf prospectus, which expires in May 2012, under which it may raise up to $1 billion in medium-term notes. As at September 30, 2010 CPLP has not drawn on the shelf prospectus.

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and where applicable, net of financial assets that generate cash inflows to meet cash outflows on financial liabilities as at September 30, 2010:

	Due within 1 year	Due between 1 and 2 years	Due between 2 and 3 years	Due between 3 and 4 years	Due between 4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Long-term debt	$ 35	$ 303	$ 436	$ 209	$ 15	$ 791	$ 1,789
Interest payments on long-term debt	101	91	76	63	50	338	719
Accounts payable and accrued liabilities [1]	249	-	-	-	-	-	249
Other current liabilities	6	-	-	-	-	-	6
Loan commitments	6	-	-	-	-	-	6
Derivative financial liabilities:							
Net forward foreign exchange contracts	2	1	1	2	1	1	8
Net commodity contracts-for-differences	82	19	1	-	-	-	102
Total	$ 481	$ 414	$ 514	$ 274	$ 66	$ 1,130	$ 2,879

[1] Excluding accrued interest on long-term debt of $18 million.

11. Commitments:

During the third quarter of 2010, the Company's subsidiary, CPLP, entered into an agreement to acquire the Island Generation Facility (Island Generation), a 275 MW gas-fired combined cycle power plant at Campbell River, British Columbia, from a third party. The transaction closed on October 19, 2010. Subject to market conditions, the Company expects to finance the estimated purchase price of $205 million, plus closing costs, with a combination of debt and equity. The estimated purchase price consists of the $207 million base purchase price, less estimated normal working capital adjustments of approximately $2 million. The Company is in the process of finalizing the purchase price allocation. Island Generation is fully contracted from April 1, 2010 to April 2022 under a tolling arrangement with a third party. The third party to the tolling arrangement will be responsible for the fuel supply to the facility.

During the second quarter of 2010, the Company's Port Dover & Nanticoke Wind Project (PDNW) was selected for the award of a contract to sell power to a third party. The 105 megawatt (MW) PDNW project would be located in southern Ontario, and developed by a subsidiary of the Company at an expected cost of $340 million. Energy generated by PDNW would be sold under a 20-year contract with the third party. Construction of PDNW will commence upon receipt of all required regulatory approvals and commercial operation is expected to commence in the fourth quarter of 2012.

During the first quarter of 2010, the Company's Quality Wind Project (Quality Wind) was selected, by a third party, for the award of an Energy Purchase Agreement (EPA). The 142 MW wind power project would be located in northeastern British Columbia, and developed by a subsidiary of the Company at an expected cost of $455 million. Energy generated by Quality Wind would be sold under a 25-year EPA with the third party. Construction of Quality Wind will commence upon receipt of all required regulatory approvals and commercial operation is expected to commence no later than the spring of 2013.

12. Guarantees:

The Company has issued letters of credit for $95 million (December 31, 2009 - $119 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

Prior to the July 2009 acquisition of subsidiaries and assets from EPCOR Utilities Inc. (EPCOR), EPCOR issued parental guarantees on behalf of former EPCOR subsidiaries to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements. At September 30, 2010, EPCOR continues to have outstanding parental guarantees on behalf of Capital Power totaling $1 million (December 31, 2009 - $1,295 million) related to subsidiaries of Capital Power.

(Unaudited, tabular amounts in millions of dollars)

13. Segment disclosures:

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, Illinois, New Jersey, New York, North Carolina and Washington.

Geographic information

	Three months ended September 30, 2010				Three months ended September 30, 2009			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 423	$ 85	$ -	$ 508	$ 424	$ 87	$ -	$ 511
Inter-area revenues	(4)	1	3	-	5	1	(6)	-
Total revenues	$ 419	$ 86	$ 3	$ 508	$ 429	$ 88	$ (6)	$ 511

	Nine months ended September 30, 2010			
	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$1,083	$ 237	$ -	$1,320
Inter-area revenues	3	6	(9)	-
Total revenues	$1,086	$ 243	$ (9)	$1,320

	As at September 30, 2010				As at December 31, 2009			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Property, plant and equipment	$ 2,889	$ 508	$ -	$3,397	$2,734	$ 508	$ -	$3,242
Goodwill	$ 104	$ 37	$ -	$ 141	$ 104	$ 36	$ -	$ 140

14. Comparative figures:

The comparative balance sheet figures for accounts payable and accrued liabilities and non-controlling interests have been recast to reflect the accrual of $18 million of distributions to non-controlling interests that were declared in the fourth quarter of 2009 for which the accrual was previously omitted from the December 31, 2009 financial statements. In the opinion of management of the Company, the amount of the recast is not considered to be material.

Certain of the comparative figures for the three months ended September 30, 2009 have been reclassified to conform with the current period’s presentation.