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

For immediate release April 30, 2010

# Capital Power reports first quarter 2010 results

**EDMONTON, Alberta** – Capital Power Corporation ("Capital Power", or the "Company") (TSX: CPX) today released its financial results for the three month period ended March 31, 2010. Normalized net income, after adjusting for one-time items and fair value adjustments, was $12 million or $0.55 per share in the first quarter of 2010.

"The Company's performance in the first quarter of 2010 was ahead of management's expectations," said Brian Vaasjo, President and Chief Executive Officer of Capital Power Corporation. "Alberta spot power prices continued to remain low in the first quarter; however, the Company's strategy to sell forward a substantial portion of its Alberta power portfolio for the first quarter proved to be prudent as the captured price was approximately 63% higher than Alberta spot power prices."

"Our recent announcements on long-term contract wins for our Quality Wind and Port Dover & Nanticoke projects, with BC Hydro and the Ontario Power Authority respectively, continue our successful execution of Capital Power's growth strategy," continued Vaasjo. "We will be investing nearly $800 million into wind projects, exceeding our 2010 target of committing at least $500 million to capital opportunities. Once construction of the wind projects is completed in late 2012 and early 2013, they will provide an additional 247 megawatts of generation capacity."

| **Operational and Financial Highlights**(1) (unaudited) *(millions of dollars except per share and operational amounts)* | **Three months ended March 31, 2010** | **Three months ended December 31, 2009** | **Three months ended September 30, 2009**(3) |
|---|---|---|---|
| Electricity generation (GWh) | 3,529 | 3,481 | 3,534 |
| Generation plant availability (%) | 96% | 92% | 95% |
| Revenues | $499 | $497 | $511 |
| Gross margin(2) | $216 | $216 | $218 |
| Operating margin(2) | $167 | $154 | $169 |
| Normalized net income(2) | $12 | $4 | $9 |
| Normalized earnings per share(2) | $0.55 | $0.18 | $0.42 |
| Net income | $13 | $7 | $14 |
| Earnings per share | $0.60 | $0.33 | $0.64 |
| Dividends declared per share | $0.315 | $0.315 | $0.315 |
| Funds from operations(2) | $112 | $71 | $93 |
| Funds from operations excluding non-controlling interests in CPILP(2) | $87 | $49 | $70 |
| Capital expenditures | $78 | $127 | $108 |

(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 three months ended March 31, 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 April 30, 2010.
(3) Revenues for the three months ended September 30, 2009 have been restated for a reclassification which resulted in a reduction of revenue and energy purchases by $14 million each. The restatement had no impact on gross margin, operating margin or net income.

## Corporate Updates

### Sale of interest in Battle River PSA

On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of $64 million resulting in a pre-tax gain of $28 million and $2 million of associated income taxes.

This sale was pursuant to the agreement entered into in June 2006 whereby the Company agreed to sell its Battle River Power Purchase Arrangement (PPA) and related interest in the Battle River PSA to ENMAX Corporation over a four-year period ending in January 2010. An initial interest of 55% was sold for cash proceeds of $343 million in June 2006, followed by the sale of 10% interests on each of January 1, 2007, January 15, 2008 and January 15, 2009 for cash proceeds of $59 million, $53 million and $47 million, respectively.

The after-tax gain was $26 million for the sale of the 15% interest in January 2010 compared with $26 million for the sale of the 10% interest in January 2009. The proportionately lower gain in 2010 reflected the increase in the asset's carrying amount in July 2009 when it was acquired in conjunction with the Company's initial public offering, reorganization and acquisition of the power generation business from EPCOR. The Company's purchase price for the acquisition from EPCOR was allocated to the assets acquired and liabilities assumed based on their estimated fair values. Accordingly, approximately $11 million was added to the carrying amount for the 15% interest in the Battle River PSA at the time of the acquisition from EPCOR, representing the Company's 27.8% interest in the asset's fair value increment. As a result, the sale had no impact on the Company's net income after the deduction of the non-controlling interests.

### Quality Wind project

On March 11, 2010, the Company's Quality Wind project was selected by BC Hydro for the award of an Energy Purchase Agreement, which has since been signed by the two parties. The project is for the development of a 142-MW wind farm near Tumbler Ridge, BC and is expected to cost approximately $455 million. Construction of the project is subject to regulatory approvals, including completion of the provincial environmental assessment which is currently in progress, and approval of the Energy Purchase Agreement by the BC Utilities Commission. The Company anticipates commercial operation of this project to commence no later than the spring of 2013 when clean renewable energy generated by Quality Wind will be sold under a 25-year Energy Purchase Agreement with BC Hydro.

The Energy Purchase Agreement supports the Company's strategy to maintain a balance between long-term contracted and merchant generation. The project also complements the Company's portfolio of assets which is predominantly coal and natural gas power sourced.

### Port Dover & Nanticoke Wind project

On April 8, 2010, the Ontario Power Authority (OPA) selected the Company's Port Dover & Nanticoke Wind development project for the award of a contract to sell power. The 105-MW project is being proposed in an area in southern Ontario where the Company has optioned lands totaling over 8,900 acres. The project has an expected cost of up to $340 million and is anticipated to enter commercial operation in the fourth quarter of 2012.

Under the terms of the OPA's Feed-in-Tariff program, the contracted price for power at commercial operation of the project will be $135 per MWh escalated by inflation between the contract signing date and commercial operation date. Thereafter, 20 per cent of the contract price will escalate annually at inflation throughout the 20-year contract term.

Construction of the project is subject to regulatory approvals, including Ontario's Renewable Energy Approval process which is currently in progress for the project.

**Analyst Conference Call and Webcast**

Capital Power will be hosting a conference call and live webcast with analysts on May 3, 2010 at 1:00 pm (ET) to discuss first quarter results. The conference call dial-in numbers are: (416) 340-8018 or (866) 223-7781 (toll-free). Interested parties may access the webcast on the Company's website at www.capitalpower.com. An archive of the webcast will be available on the website.

A replay of the conference call will be available following the call at: (416) 695-5800 or (800) 408-3053 (toll-free) and entering pass code 3681404. The replay will be available until 11:59 p.m. (ET) on May 10, 2010.

**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 31 facilities in Canada and the U.S. totaling approximately 3,500 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
# March 31, 2010

## Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated April 30, 2010, should be read in conjunction with the unaudited interim consolidated financial statements of Capital Power Corporation (the Company) and its subsidiaries for the three months ended March 31, 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 31. 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 months ended March 31, 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 three months ended March 31, 2010 do not include prior year comparative information. To facilitate the analysis of the Company's unaudited financial statements this MD&A includes unaudited pro forma consolidated financial information for the three months ended March 31, 2009. As the comparative period predates 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.

### Overview

The Company's performance in the first quarter of 2010 was ahead of management's expectations. Plant availability averaged 96% which was 1% lower than in the first quarter of 2009. Alberta spot power prices remained low in the first quarter of 2010 and averaged $41 per megawatt hour (MWh) compared with $63/MWh for the first quarter of 2009. However, the Company had sold forward a substantial portion of its Alberta portfolio and the fixed pricing for the sold forward portion combined with merchant trading activity resulted in a realized power price for the Alberta portfolio of approximately $67/MWh for the quarter. Construction continued on the Company's major construction projects including Keephills 3 and Capital Power Income L.P.'s (CPILP) Oxnard turbine replacement as well as its enhancements of the North Carolina plants.

In March 2010, the Company's Quality Wind development project was selected by BC Hydro to receive an Energy Purchase Agreement, and in April 2010, the Ontario Power Authority (OPA) selected the Company's Port Dover & Nanticoke Wind Project for the award of a contract to sell power. Capital Power expects to invest $795 million in these two projects and once complete, they are expected to provide an additional 247 megawatts (MW) of generation capacity. Capturing these two contracts means that the Company has achieved its growth target of at least $500 million of new capital expenditure commitments in 2010.

The Company's outstanding share capital on March 31, 2010 consisted of 21.75 million common shares, 56.625 million special voting shares and one special limited voting share.

## Significant Events

### Sale of interest in Battle River PSA

On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of $64 million resulting in a pre-tax gain of $28 million and $2 million of associated income taxes.

This sale was pursuant to the agreement entered into in June 2006 whereby the Company agreed to sell its Battle River Power Purchase Arrangement (PPA) and related interest in the Battle River PSA to ENMAX Corporation over a four-year period ending in January 2010. An initial interest of 55% was sold for cash proceeds of $343 million in June 2006, followed by the sale of 10% interests on each of January 1, 2007, January 15, 2008 and January 15, 2009 for cash proceeds of $59 million, $53 million and $47 million, respectively.

The after-tax gain was $26 million for the sale of the 15% interest in January 2010 compared with $26 million for the sale of the 10% interest in January 2009. The proportionately lower gain in 2010 reflected the increase in the asset's carrying amount in July 2009 when it was acquired in conjunction with the Company's IPO, reorganization and acquisition of the power generation business from EPCOR. The Company's purchase price for the acquisition from EPCOR was allocated to the assets acquired and liabilities assumed based on their estimated fair values. Accordingly, approximately $11 million was added to the carrying amount for the 15% interest in the Battle River PSA at the time of the acquisition from EPCOR, representing the Company's 27.8% interest in the asset's fair value increment. As a result, the sale had no impact on the Company's net income after the deduction of the non-controlling interests.

### Quality Wind project

On March 11, 2010, the Company's Quality Wind project was selected by BC Hydro for the award of an Energy Purchase Agreement, which has since been signed by the two parties. The project is for the development of a 142-MW wind farm near Tumbler Ridge, BC and is expected to cost approximately $455 million. Construction of the project is subject to regulatory approvals, including completion of the provincial environmental assessment which is currently in progress, and approval of the Energy Purchase Agreement by the BC Utilities Commission. The Company anticipates commercial operation of this project to commence no later than the spring of 2013 when clean renewable energy generated by Quality Wind will be sold under a 25-year Energy Purchase Agreement with BC Hydro.

The Energy Purchase Agreement supports the Company's strategy to maintain a balance between long-term contracted and merchant generation. The project also complements the Company's portfolio of assets which is predominantly coal and natural gas power sourced.

## Subsequent Events

### Port Dover & Nanticoke Wind project

On April 8, 2010, the OPA selected the Company's Port Dover & Nanticoke Wind development project for the award of a contract to sell power. The 105-MW project is being proposed in an area in southern Ontario where the Company has optioned lands totaling over 8,900 acres. The project has an expected cost of up to $340 million and is anticipated to enter commercial operation in the fourth quarter of 2012.

Under the terms of the OPA's Feed-in-Tariff program, the contracted price for power at commercial operation of the project will be $135 per MWh escalated by inflation between the contract signing date and commercial operation date. Thereafter, 20 per cent of the contract price will escalate annually at inflation throughout the 20-year contract term.

Construction of the project is subject to regulatory approvals, including Ontario's Renewable Energy Approval process which is currently in progress for the project.

## The Business

The Company's power generation operations and assets are owned by Capital Power LP (CPLP), a subsidiary of the Company. At March 31, 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 effective July 2009.

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, pursuant to various management and operation agreements, provides management and administrative services to CPILP and the Company's Canadian limited partnerships;
- 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 three months ended March 31, 2010 or on the Company's consolidated total assets or total liabilities as at March 31, 2010. CPLP's consolidated revenues, income from continuing operations, income before income tax expense and non-controlling interests for the three months ended March 31, 2010, and consolidated total assets and total liabilities as at March 31, 2010 represent 97% or more of the corresponding consolidated items of the Company.

## Summary of Financial and Other Information

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 information**

| (unaudited, GWh) **Electricity generation[(1)]** | Three months ended March 31, 2010 | March 31, 2009 |
|---|---|---|
| Alberta commercial plants | | |
| Genesee 3 | 483 | 485 |
| Joffre | 41 | 106 |
| Clover Bar Energy Centre 1, 2 and 3[(2)] | 43 | 5 |
| Taylor Coulee Chute | - | - |
| Clover Bar Landfill Gas | 10 | 10 |
| Weather Dancer | - | - |
| | 577 | 606 |
| Alberta contracted plants | | |
| Genesee 1 | 813 | 807 |
| Genesee 2 | 825 | 821 |
| | 1,638 | 1,628 |
| Ontario and British Columbia contracted plants | | |
| Kingsbridge 1 | 26 | 32 |
| Miller Creek | 7 | 3 |
| Brown Lake | 13 | 14 |
| | 46 | 49 |
| CPILP plants[(3)] | 1,268 | 1,299 |
| **Total** | **3,529** | **3,582** |

(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.

| (unaudited) | Three months ended | |
|---|---|---|
| **Generation plant availability**[1] | March 31, 2010 | March 31, 2009 |
| Alberta commercial plants | | |
| Genesee 3 | 100% | 100% |
| Joffre | 100% | 98% |
| Clover Bar Energy Centre 1, 2 and 3[4] | 72% | 99% |
| Taylor Coulee Chute | 98% | 100% |
| Clover Bar Landfill Gas | 96% | 96% |
| Weather Dancer | 83% | 57% |
| | 98% | 99% |
| Alberta contracted plants | | |
| Genesee 1 | 99% | 100% |
| Genesee 2 | 99% | 100% |
| | 99% | 100% |
| Ontario and British Columbia contracted plants | | |
| Kingsbridge 1 | 99% | 99% |
| Miller Creek | 37% | 74% |
| Brown Lake | 97% | 97% |
| | 71% | 89% |
| CPILP plants[3] | 95% | 94% |
| **Average**[2] | **96%** | **97%** |

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

(4) 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.

The decrease in electricity generation for the three months ended March 31, 2010 compared with the corresponding period in 2009 primarily relates to the Joffre and CPILP plants, partly offset by higher output from Clover Bar Energy Centre. Joffre is a mid-merit plant which operates when it is economical to do so. As a result of lower Alberta power prices and lower price volatility, Joffre was dispatched less in the first quarter of 2010.

Clover Bar Energy Centre includes Units 1, 2, and 3 for the three months ended March 31, 2010 whereas only Unit 1 had been commissioned before the first quarter of 2009. Unit 3 was taken offline for 18 days in the first quarter of 2010 for a high pressure oil system inspection and was back online on March 9, 2010. Unit 2 was taken offline for 21 days in February and early March for the same inspection procedure and was back online on March 5, 2010. A mechanical failure in the main turbine section of Unit 2, unrelated to the oil system inspection, was subsequently identified and the repair work was initiated in late March. Unit 2 was offline for a total of 43 days in the first quarter of 2010 and is not expected to be back online until July/August 2010.

Miller Creek Units 1 and 2 were offline for scheduled maintenance for a combined total of 77 days during the first quarter of 2010 compared with 33 days for scheduled maintenance in the corresponding period in 2009. The decrease in availability did not impact the generation output at Miller Creek as water flow levels were higher in the first three months of 2010.

Lower output from the CPILP plants was primarily due to reduced dispatch of the Manchief plant. In the first quarter of 2009 Manchief benefited from increased demand as a result of outages at other plants in the area.

**Financial highlights**

| (unaudited, $millions, except earnings per share) | Three months ended March 31, 2010 | Three months ended March 31, 2009(2) |
|---|---|---|
| Revenues | $ 499 | $ 653 |
| Gross margin(1) | 216 | 199 |
| Operating margin(1) | 167 | 145 |
| Net income | 13 | 19 |
| Earnings per share(4) | $0.60 | N/A |
| Fully diluted earnings per share(3)(4) | $0.60 | N/A |
| Normalized earnings per share(1)(4) | $0.55 | N/A |
| Funds from operations(1)(4) | 112 | N/A |
| Capital expenditures(4) | 78 | N/A |
| Long-term debt including current portion(4) | 1,634 | N/A |
| Total assets(4) | 4,952 | 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 three months ended March 31, 2009 are unaudited pro forma consolidated financial information included in the Consolidated Net Income 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 three months ended March 31, 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 March 31, 2010 | Three months ended December 31, 2009 |
|---|---|---|
| Funds from operations(1) | $ 112 | $ 71 |
| Funds from operations excluding non-controlling interests in CPILP(1) | $ 87 | $ 49 |

(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 excluding non-controlling interests in CPILP were approximately $38 million higher for the first quarter of 2010 compared with the fourth quarter of 2009. The increase was primarily due to higher operating income excluding unrealized fair value changes, from the Alberta commercial power portfolio and Alberta contracted plants, and lower indirect administration expenses. Trading activities for the Alberta commercial power portfolio that settled in the first quarter of 2010 when spot power prices were low resulted in a higher realized price for the portfolio. There were no outages at the Alberta contracted plants in the first quarter of 2010 compared with a scheduled outage at Genesee 1 in the fourth quarter of 2009. Accordingly, payments made for availability penalties and maintenance costs reduced funds from operations in the fourth quarter of 2009. Indirect administration expense for the fourth quarter of 2009 included transition costs relating to the Reorganization whereas no transition costs were incurred in the first quarter of 2010.

The Company uses funds from operations as its primary operating cash flow measure. Since the non-controlling interests in CPILP's funds from operations are approximately 69.7%, (69.5% at December 31, 2009) 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. The quarter-over-quarter changes in both measures were not significantly different ($41 million compared with $38 million) as CPILP's funds from operations were relatively stable over the two periods.

## Normalized net income and normalized earnings per share

| (unaudited, $millions except earnings per share) | Three months ended | |
|---|---|---|
| | March 31, 2010 | December 31, 2009 |
| **Earnings per share** | **$ 0.60** | **$ 0.33** |
| **Net income** | **13** | **7** |
| Adjustments | (1) | (3) |
| **Normalized net income[(1)]** | **12** | **4** |
| **Normalized earnings per share[(1)]** | **$ 0.55** | **$ 0.18** |

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

Normalized net income was higher in the first quarter of 2010 compared with the fourth quarter of 2009, primarily due to higher operating income, excluding unrealized fair value changes, from the Alberta commercial plants and Alberta contracted plants, and lower indirect administration expenses 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. Normalized earnings per share reflect normalized net income divided by 21.75 million weighted average common shares outstanding. See Non-GAAP Financial Measures.

## Consolidated Net Income

### Pro forma consolidated financial information

The pro forma consolidated financial information for the three months ended March 31, 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 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 financial position and 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 financial position as of any future date or results of operations for any future period. Actual adjustments will differ 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 three months ended March 31, 2010 and the audited financial statements of the Company for the six months ended December 31, 2009.

| (unaudited, $millions) | Three months ended March 31, 2010 | March 31, 2009[1] |
|---|---|---|
| Revenues | $ 499 | $ 653 |
| Energy purchases and fuel | 283 | 454 |
| | 216 | 199 |
| Operations, maintenance and direct administration | 44 | 49 |
| Indirect administration | 26 | 29 |
| Property taxes | 5 | 5 |
| Depreciation, amortization and asset retirement accretion | 46 | 47 |
| Foreign exchange losses | 1 | - |
| Gain on sale of power syndicate agreement | (28) | (30) |
| Net financing expenses | 18 | 35 |
| | 112 | 135 |
| Income (loss) before income tax expense and non-controlling interests | 104 | 64 |
| Income tax expense (reductions) | - | (8) |
| Income before non-controlling interests | 104 | 72 |
| Non-controlling interests | 91 | 53 |
| **Net income** | **$ 13** | **$ 19** |

(1) Unaudited pro forma consolidated information for the three months ended March 31, 2009 conforms to the presentation adopted for the three months ended March 31, 2010.

**Consolidated Net Income**

| (unaudited, $millions) | |
|---|---|
| **Pro forma consolidated net income for the three months ended March 31, 2009** | **$ 19** |
| Unrealized changes in the fair value of CPILP's derivative instruments | 47 |
| Lower net financing expenses | 17 |
| Higher CPILP operating margin | 10 |
| Unrealized changes in the fair value of CPLP's derivative instruments and natural gas inventory held for trading | (22) |
| Higher income taxes | (8) |
| Lower Alberta contracted plants operating margin | (5) |
| Lower other portfolio activities operating margin | (4) |
| Lower Alberta commercial plants operating margin | (3) |
| | 32 |
| Higher non-controlling interests: | |
| - CPLP | (1) |
| - CPILP | (36) |
| - Preferred share dividends paid by subsidiary company | (1) |
| | (38) |
| Decrease in net income | (6) |
| **Net income for the three months ended March 31, 2010** | **$ 13** |

Net income decreased $6 million for the three months ended March 31, 2010 compared with the three months ended March 31, 2009 due to the net impact of the following:

- The year-over-year change in unrealized fair value adjustments for CPILP's foreign exchange and natural gas contracts that were not designated as hedges for accounting purposes was due to a net loss of $3 million in the first quarter of 2010 compared with a net loss of $50 million in the first quarter of 2009. The fair value of the natural gas contracts declined in both periods due to decreases in the future prices for natural gas with a larger decrease in the first quarter of 2009 as certain of CPILP's natural gas contracts were designated as hedges for accounting purposes effective July 1, 2009. The loss for the first quarter of 2010 was partly offset by an increase in the fair value of CPILP's foreign exchange contracts due to strengthening future prices for the Canadian dollar relative to the U.S. dollar, whereas the fair value of the foreign exchange contracts decreased in the first quarter of 2009 due to weakening future prices.

- The decrease in financing expenses for the three months ended March 31, 2010 compared with the corresponding period in 2009 primarily relates to lower interest expense and higher interest capitalized for construction work in progress. The Company capitalizes borrowing costs as part of its cost of construction projects and in the first three months of 2010 the Company had higher construction work in progress compared with the corresponding period in 2009.
- The operating margin for the CPILP plants was higher primarily due to higher prices realized on foreign exchange contracts that settled in the first quarter of 2010, higher dispatch and availability of the Naval Station plant and higher water flows at the BC hydroelectric plants.
- The unfavourable year-over-year variance for unrealized changes in the fair value of CPLP's derivative instruments and natural gas inventory held for trading that were not designated as hedges for accounting purposes was primarily due to an unfavourable variance for power derivative contracts partly offset by favourable variances for natural gas derivative contracts and the Joffre contract-for-differences (CfD). The impact of decreases in Alberta forward power prices on the Alberta portfolio position for electricity derivative contracts in both periods and less power price volatility in the three months ended March 31, 2010 resulted in a smaller gain for these contracts in the first quarter of 2010. The fair value of natural gas inventory and derivative contracts increased in the first quarter of 2010 and decreased in the corresponding period in 2009 due to the impact of decreased forward natural gas prices in both periods on the Company's natural gas portfolio positions. The fair value of the Joffre contract-for-differences (CfD) increased in the three months ended March 31, 2010 and decreased in the corresponding period in 2009. See Unrealized Changes in Fair Value of Derivative Instruments and Natural Gas Inventory held for Trading under Results by Plant Category.
- Income taxes were higher primarily due to higher income before taxes and non-controlling interests partly offset by a net favourable adjustment in the first quarter of 2010 for the impact of changes in income tax laws on future income tax assets and liabilities.
- The operating margin for Alberta contracted plants was lower primarily due to lower net availability incentive revenues as a result of lower average Alberta power prices, and higher coal costs.
- The operating margin for other portfolio activities was lower primarily due to reduced trading activity and lower ancillary revenues.
- The decrease in operating margin for the Alberta commercial plants was primarily due to lower generation from Joffre as a result of lower average Alberta power prices, and decreased generation from the acquired PPAs as a result of the sale of the remaining interest in the Battle River PPA in January 2010.
- Non-controlling interests reflect higher income before taxes from CPLP and CPILP in the three months ended March 31, 2010 compared with the three months ended March 31, 2009.

## Results by Plant Category

| (unaudited, $millions) | Three months ended March 31, 2010 | March 31, 2009[2] |
|---|---|---|
| **Revenues** | | |
| Alberta commercial plants and portfolio optimization | $ 235 | $ 336 |
| Alberta contracted plants | 72 | 74 |
| Ontario and British Columbia contracted plants | 3 | 4 |
| CPILP plants | 139 | 145 |
| Other portfolio activities | 43 | 52 |
| Inter-plant category transaction eliminations | (10) | (13) |
| | 482 | 598 |
| Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading | 12 | 71 |
| Unrealized changes in fair value of CPILP's foreign exchange contracts | 5 | (16) |
| | 17 | 55 |
| | **$ 499** | **$ 653** |
| **Gross margin**[1] | | |
| Alberta commercial plants and portfolio optimization | $ 65 | $ 68 |
| Alberta contracted plants | 59 | 62 |
| Ontario and British Columbia contracted plants | 3 | 4 |
| CPILP plants | 77 | 77 |
| Other portfolio activities | 15 | 17 |
| Inter-plant category transaction eliminations | (9) | (10) |
| | 210 | 218 |
| Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading | 9 | 31 |
| Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts | (3) | (50) |
| | 6 | (19) |
| | **$ 216** | **$ 199** |
| **Operating margin**[1] | | |
| Alberta commercial plants and portfolio optimization | $ 55 | $ 58 |
| Alberta contracted plants | 46 | 51 |
| Ontario and British Columbia contracted plants | 2 | 3 |
| CPILP plants | 53 | 43 |
| Other portfolio activities | 5 | 9 |
| Inter-plant category transaction eliminations | - | - |
| | 161 | 164 |
| Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading | 9 | 31 |
| Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts | (3) | (50) |
| | 6 | (19) |
| | **$ 167** | **$ 145** |

(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 three months ended March 31, 2009 conforms to the presentation for the three months ended March 31, 2010. See Consolidated Net Income.

| Spot price averages for the three months ended | March 31, 2010 | March 31, 2009 |
|---|---|---|
| Alberta power ($/MWh)(1) | $ 40.78 | $ 63.36 |
| Eastern region power ($/MWh)(1) | $ 33.84 | $ 42.98 |
| Western region power (Mid-C) ($/MWh)(1) | $ 42.70 | $ 43.49 |
| Alberta natural gas (AECO) ($/Gj)(2) | $ 4.72 | $ 4.68 |

| | | |
|---|---|---|
| **Capital Power's Alberta portfolio captured power price** ($/MWh)(1)(3) | 67 | 66 |

(1) Megawatt hours (MWh)

(2) Gigajoule (Gj). AECO means a historical virtual trading hub, located in Alberta, which is now known as the Nova Inventory Transfer System operated by TransCanada Pipelines Limited.

(3) Captured power price represents the price realized on the Company's commercial contracted sales and portfolio optimization activities.

**Alberta commercial plants and portfolio optimization**

Alberta commercial plants and portfolio optimization revenues, gross margin and operating margin for the three months ended March 31, 2010 were lower compared with the corresponding period in 2009 primarily due to lower generation at the Joffre plant as a result of a significant decrease in Alberta power prices, and decreased generation sales from the acquired PPAs due to the sale of the remaining interest in the Battle River PPA in January 2010.

The average Alberta power spot price was $41/MWh for the three months ended March 31, 2010 compared with $63/MWh for the three months ended March 31, 2009. Since 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 Company's average realized price for the portfolio for the three months ended March 31, 2010 was approximately $67/MWh, or $26/MWh higher than the average spot price.

The $101 million decrease in revenues from the Alberta commercial plants and portfolio optimization included $65 million for the impact of lower Alberta power prices on the price for the supply of electricity to EPCOR's regulated rate tariff (RRT) customers. Revenues for the acquired PPAs were $24 million lower due to the impact of lower Alberta power prices on generation sales to the Alberta Balancing Pool as well as lower generation sales resulting from the sale of the remaining interest in the Battle River PPA in January 2010. The decrease in revenues also included $11 million for Genesee 3 due to lower Alberta power prices and $5 million for Joffre due to lower output. These decreases were partly offset by higher gains on merchant power derivative sell contracts that settled in the first quarter of 2010, resulting from higher contract prices relative to spot prices and a higher volume of derivative sell contracts.

Clover Bar Energy Centre Units 2 and 3 were offline for 43 and 18 days, respectively, in the first quarter of 2010 as a result of a high pressure oil system inspection of both units and a subsequently identified mechanical failure in the main turbine section of Unit 2. Since the Alberta spot power prices for the first quarter of 2010 were low with little volatility, there were few occasions when it would have been economical to dispatch these peaking units at Clover Bar Energy Centre. Therefore the outages did not have a material impact on the Alberta commercial plants' revenues, gross margin and operating margin. In addition, repair work was covered under warranty by the original contractor and did not have a material impact on operating and maintenance expenses.

The decrease in revenue from the Company's RRT business did not have a significant impact on operating margin 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. Therefore the reduction in RRT supply volumes also had an immaterial impact on operating margin.

**Alberta contracted plants**

Revenues decreased $2 million primarily due to lower net availability incentive revenues as a result of lower rolling average power prices. The price for availability incentive income and penalties is a function of a 30-day rolling average of Alberta power prices which was generally lower in the first three months of 2010 than in the corresponding period in 2009. In addition, the gross margin and operating margin were impacted by increased fuel costs as a result of an increase in the volume of coal mined in the first quarter of 2010.

**Ontario and British Columbia contracted plants**

The lower revenues, gross margin and operating margin for the Ontario and British Columbia contracted plants category reflects lower generation volume at Kingsbridge I as a result of lower wind resources.

**CPILP plants**

CPILP plant revenues experienced a number of small increases and decreases in revenues compared with the corresponding period in 2009. As a result of having a diversified portfolio of plants, revenues excluding fair value changes in foreign exchange contracts was relatively consistent with the first quarter of 2009.

The operating margin for the CPILP plants increased $10 million for the three months ended March 31, 2010 compared with the corresponding period in 2009 due to higher prices on the foreign exchange contracts that settled in the first quarter of 2010 than those that settled in the first quarter of 2009, higher dispatch of Naval Station and higher water flows at the BC hydroelectric plants. In addition, operations and maintenance expenses were lower primarily due to fewer maintenance overhauls in the 2010 period and a weaker U.S. dollar relative to the Canadian dollar.

**Other portfolio activities**

The decrease in revenues, gross margin and operating margin primarily reflects overall lower trading activity and lower ancillary revenue.

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

Revenues for unrealized changes in the fair value of derivative instruments and natural gas inventory held for trading decreased $38 million in the three months ended March 31, 2010 compared with the corresponding period in 2009. Gross margin for the unrealized changes in the fair value of these assets increased $25 million.

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 revenues by $14 million and increased energy purchases by $8 million (a gain of $6 million) in the three months ended March 31, 2010. In the corresponding period in 2009, the fair value changes of these instruments increased revenues and expenses by $70 million and $36 million, respectively (a gain of $34 million). These changes primarily reflect the impact of decreases in the Alberta forward power prices on portfolio positions for these instruments in both periods, and less price volatility in the three months ended March 31, 2010.

CPILP's revenues included a net gain of $5 million for changes in the fair value of foreign exchange contracts in the three months ended March 31, 2010 due to strengthening future prices for the Canadian dollar relative to the U.S. dollar compared with a net loss of $16 million in the corresponding period in 2009 due to weakening future prices for the Canadian dollar.

Decreases in the fair value of CPILP's natural gas contracts increased fuel expense by $8 million in the three months ended March 31, 2010 and $34 million in the corresponding period in 2009. The loss was smaller in the first quarter of 2010 because CPILP designated certain of its natural gas contracts as hedges for accounting purposes effective July 1, 2009. Accordingly, the $35 million decrease in the fair value of the designated contracts in the first quarter of 2010 was recorded in other comprehensive income whereas none of the contracts were designated as hedges for the first quarter of 2009. All of the fair value losses on the natural gas contracts were recorded in fuel expense in the income statement in the first quarter of 2009.

Changes in the fair value of CPLP's Joffre contract-for-differences (CfD) decreased revenues and energy purchases by $2 million and $5 million, respectively (a gain of $3 million) in the three months ended March 31, 2010. In the corresponding period in 2009, the fair value changes of this instrument increased revenues and expenses by $1 million and $4 million, respectively (a loss of $3 million). The gain in the first quarter of 2010 reflected decreased forward natural gas prices partly offset by decreased forward power prices relative to the prices in the CfD. The CfD is a tolling agreement between the Company and the Joffre joint venture for the sale of 50 MW of the plant's capacity to the Company at a contracted floating price calculated monthly. The joint venture owns the Joffre facility and consists of Nova Chemicals Corporation, ATCO Power Canada Ltd. and the

Company. The purpose of the CfD is to minimize the joint venture's exposure to spot electricity prices.

## Consolidated Other Expenses

| (unaudited, $millions) | Three months ended March 31 | |
|---|---|---|
| | 2010 | 2009[1] |
| Indirect administration | 26 | 29 |
| Depreciation, amortization and asset retirement accretion | 46 | 47 |
| Foreign exchange losses | 1 | - |
| Net financing expenses | 18 | 35 |
| Income taxes (reductions) | - | (8) |
| Non-controlling interests | | |
| - CPLP | 76 | 75 |
| - CPILP | 12 | (24) |
| - Preferred share dividends paid by CPI Preferred Equity Ltd.[2] | 3 | 2 |

(1) The presentation of consolidated other expenses for the three months ended March 31, 2009, conforms to the presentation for the three months ended March 31, 2010. See Consolidated Net Income.

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

**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 decrease in indirect administration expense was primarily due to higher business development costs in 2009.

**Net financing expenses**

Financing expenses were $17 million lower for the three months ended March 31, 2010 than for the corresponding period in 2009. The decrease was primarily due to lower interest expense and higher capitalized interest combined with no net increase in debt borrowings to fund ongoing capital requirements. See Liquidity and Capital Resources. 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 first quarter of 2010, construction work in progress, particularly for Keephills 3, was higher compared with the corresponding period in 2009.

**Income taxes (reductions)**

Income taxes for the three months ended March 31, 2010 were higher than for the corresponding period in 2009 primarily due to higher income before taxes and non-controlling interests partly offset by a net favourable adjustment in the first quarter of 2010 for the impact of changes in income tax laws on future income tax assets and liabilities.

**Non-controlling interests**

The non-controlling interests in CPILP reflect approximately 69.7% of the income from CPILP which was higher for the three months ended March 31, 2010 than for the corresponding period in the previous year. The non-controlling interests in CPLP reflect approximately 72.2% of the income from CPLP which was higher in the three months ended March 31, 2010 than the three months ended March 31, 2009. Non-controlling interests also includes 100% of the gain on sale of the Battle River PPA, as discussed under Significant Events.

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

## 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 and (v) 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 | |
|---|---|---|
| | March 31, 2010 | March 31, 2009 |
| Revenues | $ 499 | $ 653 |
| Energy purchases and fuel | 283 | 454 |
| **Gross margin** | **216** | **199** |
| Operations, maintenance, and direct administration | 49 | 54 |
| **Operating margin** | **167** | **145** |
| Deduct (add): | | |
| Indirect administration | 26 | 29 |
| Depreciation, amortization and asset retirement accretion | 46 | 47 |
| Foreign exchange losses | 1 | - |
| Gain on sale of power syndicate agreement | (28) | (30) |
| Net financing expenses | 18 | 35 |
| Income taxes (reduction) | - | (8) |
| Non-controlling interests | 91 | 53 |
| Net income | **$ 13** | $ **19** |

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 three months ended March 31, 2009 conforms to the presentation adopted for the three months ended March 31, 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, $millions) | Three months ended | |
|---|---|---|
| | March 31, 2010 | December 31, 2009 |
| **Funds from operations excluding non-controlling interests in CPILP** | **$ 87** | **$ 49** |
| Funds from operations due to non-controlling interests in CPILP | 25 | 22 |
| Funds from operations | 112 | 71 |
| Change in non-cash operating working capital | 18 | 50 |
| **Cash provided by operating activities** | **$ 130** | **$ 121** |

**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. A reconciliation of normalized net income to net income, and normalized earnings per share to earnings per share is as follows:

| (unaudited, $millions except earnings per share) | Three months ended | |
|---|---|---|
| | March 31, 2010 | December 31, 2009 |
| **Earnings per share** | **$ 0.60** | **$ 0.33** |
| **Net income** | **13** | **7** |
| Adjustments | | |
| Unrealized changes in fair value of CPLP's derivative instruments and natural gas held for trading | - | (5) |
| Unrealized changes in fair value of CPILP's derivative instruments | - | (1) |
| Venture capital investment write-down | - | 1 |
| Income tax adjustments | (1) | 2 |
| | (1) | (3) |
| **Normalized net income** | **12** | **4** |
| **Normalized earnings per share** | **$ 0.55** | **$ 0.18** |

## Balance Sheet

Changes in consolidated assets:

December 31, 2009 and March 31, 2010

| (unaudited, $millions) | Dec 31, 2009 | Increase (decrease) | March 31, 2010 | Explanation of increase (decrease) |
|---|---|---|---|---|
| Cash and cash equivalents | 52 | 13 | 65 | Refer to Liquidity and Capital Resources below. |
| Accounts receivable (including income taxes recoverable) | 304 | (86) | 218 | Lower receivables in March 2010 compared to December 2009 for wholesale and EPCOR RRT sales, and for generation sales to the Alberta Balancing Pool, due to lower power prices. |
| Derivative instruments assets (current) | 146 | 28 | 174 | Increase in fair value of derivative instrument power and natural gas contracts due to decreased forward prices. |
| Other current assets | 104 | (30) | 74 | Decrease reflects the sale of the remaining interest in the Battle River PPA. |
| Property, plant and equipment | 3,242 | 25 | 3,267 | Capital expenditures partly offset by depreciation and amortization expense and the impact of the strengthening Canadian dollar on the translation of property, plant and equipment of U.S. subsidiaries. |
| Power purchase arrangements | 528 | (22) | 506 | Amortization and the impact of the strengthening Canadian dollar on the translation of PPAs of U.S. subsidiaries. |
| Contract and customer rights and other intangible assets | 184 | (4) | 180 | |
| Derivative instruments assets (non-current) | 155 | - | 155 | |
| Future income tax assets (non-current) | 61 | (2) | 59 | |
| Goodwill | 140 | (2) | 138 | |
| Other assets | 120 | (4) | 116 | |

| Changes in consolidated liabilities and shareholders' equity: December 31, 2009 and March 31, 2010 | | | | |
|---|---|---|---|---|
| (unaudited, $millions) | Dec 31, 2009 | Increase (decrease) | March 31, 2010 | Explanation of increase (decrease) |
| Accounts payable and accrued liabilities [1] | 339 | (59) | 280 | Lower payables for energy purchases due to lower Alberta power prices, and lower maintenance overhaul payables. |
| Derivative instruments liabilities (current) | 108 | 24 | 132 | Decrease in fair value of derivative instrument power and natural gas contracts, primarily due to the impact of decreases in forward prices on derivative power and natural gas buy contracts and the reclassification of derivative liability balances for certain natural gas derivative instruments from long-term to short-term. |
| Other current liabilities | 29 | (3) | 26 | |
| Long-term debt (including current portion) | 1,719 | (85) | 1,634 | Net repayment of long-term debt outstanding under CPLP's and CPILP's credit facilities and the impact of a strengthening Canadian dollar relative to the U.S. dollar on the translation of CPILP's U.S. long-term debt. |
| Derivative instruments liabilities (non-current) | 102 | 16 | 118 | Decrease in fair value of derivative instrument natural gas supply contracts primarily due to the impact of decreases in forward prices; partly offset by the reclassification of derivative liability balances for certain derivative instruments from long-term to short-term. |
| Other non-current liabilities | 109 | (2) | 107 | |
| Future income tax liabilities (non-current) | 95 | (10) | 85 | Primarily due to the income tax impact of a decrease in unrealized fair value changes of derivative instruments. |
| Non-controlling interests[1] | 2,046 | 29 | 2,075 | Non-controlling interests' share of CPLP and CPILP net income and CPLP other comprehensive income, and CPILP unit issue, partly offset by non-controlling interests' share in CPILP and CPLP distributions and CPILP other comprehensive loss. |
| Shareholders' equity | 489 | 6 | 495 | Net Income and other comprehensive income, partly offset by common share dividends. |

[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) | Three months ended March 31, 2010 | Explanation |
| Cash from Operating Activities | $ 130 | See Funds from Operations |
| Investing | (12) | 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 | (104) | Net repayments of long-term debt outstanding under CPLP's and CPILP's credit facilities, distributions to non-controlling interests, and dividends paid to common shareholders, partly offset by proceeds from CPILP's distribution reinvestment program. |

On March 31, 2010 CPLP had $1,220 million of credit facilities, of which $1,081 million remained available. Also on March 31, 2010, CPILP had revolving credit facilities of approximately $366 million, of which $295 million remained available and Capital Power Corporation had an undrawn bank line of credit of $5 million.

Long-term debt outstanding at March 31, 2010 and December 31, 2009 consisted of the following:

| (unaudited, $millions) | March 31, 2010 | December 31, 2009 | Maturity date | Nominal interest rate |
|---|---|---|---|---|
| Long-term debt payable to EPCOR | $ 869 | $ 872 | Ranging from 2010 to 2018 | Ranging from 5.80% to 9.00% |
| Joffre Cogeneration and Brown Lake project non-recourse financing | 47 | 47 | 2020 and 2016 | Fixed 8.59% and 8.70% and floating(1) |
| CPLP revolving extendible credit facilities | 40 | 100 | 2012 | floating(1) |
| CPILP long-term debt | 692 | 715 | Ranging from 2010 to 2036 | Fixed ranging from 5.87% to 11.25% and floating(1) |
| | $ 1,648 | $ 1,734 | | |

(1) Floating interest rates are a function of the prevailing bankers' acceptance rates.

In the first quarter of 2010, CPLP and CPILP made a net repayment of $60 million and $9 million, respectively on amounts drawn under their revolving credit facilities. CPILP's outstanding long-term debt in the table above also reflects a decrease of $14 million in the first quarter of 2010 for foreign exchange on the translation of its U.S. dollar denominated debt.

The long-term debt payable to EPCOR was issued in connection with the Reorganization pursuant to a credit agreement entered into by CPLP and EPCOR on July 9, 2009. CPLP has adequate credit facilities to repay $200 million of 6.95% debt and $45 million of 9% debt, both of which are due to EPCOR in June 2010.

CPLP's credit facilities include a Syndicated Facility of up to $700 million with an initial term of three years and an extendible revolving club credit facility (Club Facility) of up to $500 million with an initial 364 day period following which any drawn portion of the facility will convert into a non-revolving facility for a one year term-out period. Borrowings and repayments under the Club Facility will be made by CPLP with each lender on an individual lender basis up to that lender's commitment, and not on a pro-rata basis.

At March 31, 2010, CPILP's committed bank credit facilities included two revolving facilities of $100 million each with terms expiring in September and October 2011, and a revolving facility of $125 million expiring in June 2011. Each of the three facilities include a U.S. co-borrower to facilitate funding of capital expenditures at the partnership's U.S. plants. CPILP also has two demand facilities, one for $20 million and the other for US$20 million.

The bank credit facilities are expected to be used primarily for the purposes of providing funds for capital expenditures, letters of credit and general corporate purposes. Letters of credit are issued to meet conditions of certain debt and service agreements, to meet the credit requirements of energy market participants and to satisfy legislated reclamation requirements. On March 31, 2010, CPILP had $69 million of long-term debt borrowings and less than $1 million of letters of credit outstanding under its credit facilities, and CPLP had $40 million of debt and $99 million of letters of credit outstanding under its 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 impacts CPLP's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

**Capital Expenditures**

| (unaudited, $ millions) | Three months ended March 31, 2010 |
|---|---|
| Keephills 3 | $ 59 |
| CPILP's Oxnard turbine replacement project | 7 |
| CPILP's North Carolina plants enhancement project | 3 |
| Other | 9 |
| Total capital expenditures | $ 78 |

Construction of Keephills 3 remains on schedule. Hydro tests on the feed water and re-heater systems and the boiler were successfully completed in April 2010, marking the achievement of a major milestone for the project. The number of staff for construction peaked in the first quarter of 2010 and is expected to decrease in the upcoming months as the project evolves from construction to commissioning. The commissioning team is increasing staff levels as commissioning activities increase on the boiler, turbine and electrical systems. CPILP expects to complete the Oxnard turbine replacement project in the second quarter of 2010 and have the plant back online in May 2010. CPILP completed the enhancements to the second unit at Southport plant in North Carolina in April 2010 and will complete the material handling improvements at Southport in the second quarter of 2010. The Company's other capital expenditures for the three months ended March 31, 2010 were primarily for the improvement of existing facilities.

**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 nine months ended December 31, 2010, excluding CPILP's cash requirements are expected to include approximately $304 million for capital expenditures, approximately $245 million for debt repayments to EPCOR, approximately $54 million for CPLP distributions to EPCOR, and approximately $21 million for Capital Power's quarterly dividends subject to approval by the Board of Directors. The estimate for CPLP distributions includes $18 million distributed on April 30, 2010 and the estimate for Capital Power's quarterly dividends includes $7 million paid on April 30, 2010 at $0.315 per share. The major capital expenditures are expected to include approximately $187 million for the Keephills 3 construction project, approximately $63 million for wind power development projects including Quality Wind and Port Dover and Nanticoke, $27 million for maintenance capital, and $17 million for emission offsets.

If 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, distributions from CPILP and the use of existing credit facilities. The Company expects to fund the Quality Wind and Port Dover & Nanticoke Wind projects under this overall financing plan.

In April 2010, the Company filed two short form base shelf prospectuses which 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, market conditions permitting. Pursuant to one of the final 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. Under this equity prospectus, EPCOR may also sell the common shares of the Company which it beneficially owns through its ownership of exchangeable limited partnership units of CPLP. Pursuant to the other final 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 nine months ended December 31, 2010 are expected to include approximately $13 million for the completion of the Roxboro and Southport enhancement project, approximately $8 million for the repowering project at Oxnard, approximately $71 million for distributions subject to approval by the CPILP Board of Directors and approximately $10 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 April 23, 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. If major investments of capital are required, CPILP may obtain new capital from external markets by utilizing its $1 billion shelf prospectus which expires 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

There were no material changes to the Company's purchase obligations, commitments or contingencies during the first quarter, including payments for the next five years and thereafter. 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 March 31, 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 three months ended March 31, 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 March 31, 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 $869 million at March 31, 2010. The interest incurred on this debt was $15 million for the three months ended March 31, 2010 of which $10 million was capitalized as property, plant and equipment for construction work in progress and the remainder was included in net financing expense.

The Company's revenues for power sold to EPCOR for resale to its customers were $102 million for the three months ended March 31, 2010. The Company's purchases of distribution and transmission services from EPCOR were $6 million and the Company contributed $7 million to EPCOR for the construction of aerial and underground transmission lines. 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 March 31, 2010 resulting from transactions with EPCOR in the first quarter of 2010 were as follows:

| (unaudited, $ millions) | March 31, 2010 |
|---|---|
| **Balance sheet** | |
| Accounts receivable | $ 40 |
| Other assets | 7 |
| Property, plant and equipment | 10 |
| Accounts payable and accrued interest on debt | 16 |

## 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 outlook is substantially the same as it was described in the December 31, 2009 MD&A, except for the following updates.

Two outages remain scheduled at Genesee in 2010; one at Genesee 2 in May and the other at Genesee 3 in October. In addition, the Alberta Electric System Operator (AESO) has indicated that a transmission upgrade project will occur in the month of May which should result in de-rates of all three units at Genesee for approximately 17 days to below their normal operating levels. The timing coincides with the previously scheduled outage at Genesee 2 and the incremental impact of the de-rates on the Company's operating margin and funds from operations in the second quarter is expected to be less than $2 million. These de-rates would not impact the Company's plant availability performance factor because they would be directed by the AESO.

The second unit at Clover Bar Energy Centre was taken offline in March due to mechanical issues which are being addressed under warranty from the supplier, and the unit may not be back online until July/August 2010. 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 previously expected benefit to operating income and cash flow from operations, of having all three units available could be affected by this outage and to mitigate this exposure, the Company will depend on the other two units and financial contracts to manage the portfolio while Unit 2 is offline. However, this outage may adversely impact the Company's ability to achieve its 94% total plant availability target for 2010.

The Company's Alberta commercial portfolio position for the forecast generation from the base-load plants for the balance of 2010 remains substantially sold forward at an average price in the low-$60/MWh range. For 2011, approximately 80% of the portfolio has been sold forward at an average contracted price of approximately $60/MWh.

Previous estimates of the earnings from CPILP for the remainder of 2010 may be adversely impacted by delays in the finalization of new PPAs for its facilities in North Carolina. The magnitude of the impact depends on the timing and final terms of the new PPAs, which are not determinable at this time.

Capital expenditures, excluding CPILP's capital expenditures, are expected to be approximately $304 million for the balance of 2010. This estimate represents an addition of $63 million for wind power development projects to the previous forecast.

## Business Risks

**Derivatives and Energy Trading Risk**

Capital Power uses derivative instruments, including futures, forwards, options and swaps, to manage its commodity and financial market risks inherent in its electricity generation operations. These activities, although intended to mitigate price volatility, expose Capital Power to other risks. When Capital Power sells power forward, it gives up the opportunity to sell power at higher prices in the future, which not only may result in lost opportunity costs but also may require Capital Power to post significant amounts of cash collateral or other credit support to its counterparties. In addition, Capital Power purchases and sells commodity-based contracts in the natural gas and electricity markets for trading purposes. In the future, Capital Power could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract.

Capital Power is exposed to market risks through its power marketing business, which involves the sale of energy, capacity and related products and the purchase and sale of fuel, transmission services and emission allowances. These market risks include, among other risks, volatility arising from location and timing differences that may be associated with buying and transporting fuel, converting fuel into energy and delivering the energy to a buyer.

In order to mitigate these risks, the Company has a Commodity Risk Management Program in place, including new risk policies effective in the first quarter of 2010 which better align the Company's risk management framework with the Company's risk profile following the Reorganization. The Program provides an infrastructure that enables the Company to manage commodity and energy trading risks associated with the energy commodity business. In addition, the Company takes market risk positions within authorized limits approved by Capital Power's executive team and Board of Directors. Key risk measures in relation to applicable limits are reported daily to the executive team and reviewed by the Board of Directors quarterly. 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 over a given period of time or holding period and a given level of confidence. Capital Power's current year VaR uses a statistical confidence interval of 99% over a five day holding period. This measure reflects a 1% probability that, over the defined holding period, 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. Capital Power's Board of Directors has established aggregate Commodity Risk limits which are monitored and reported to the executive team on a daily basis. To supplement the aggregate Commodity Risk estimates, the portfolio is stress-tested regularly to observe the effects of plausible scenarios taking into account historical volatilities and observed price movements.

Aside from the above described Derivatives and Energy Trading Risk, the Company's business and operational risks remain substantially unchanged since December 31, 2009 as provided in the Company's December 31, 2009 MD&A. For further information on business risks, refer to the Company's December 31, 2009 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. In the second quarter of 2010, the Company will review the potential impact of this section's requirements on accounting for the July 2009 Reorganization and make a decision on whether to take the election available under IFRS 1.

- 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 actual entity's 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 implementation of this standard is expected to result in increased depreciation expense for Capital Power. The Company expects to quantify this impact by the end of the second quarter of 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. Since the Company's decommissioning work is generally performed by the employees of the Company, the estimated decommissioning costs would be significantly less under IFRS than the Company's current estimates under Canadian GAAP. Accordingly, if the provisions of IAS 37 remain unchanged, there should be a decrease in the asset retirement obligation upon conversion to IFRS. However, the International Accounting Standards Board issued an exposure draft which proposes to replace IAS 37 with a new standard that would require decommissioning liabilities to be measured using third party cost estimates. The Company is quantifying the provision under both scenarios. A revised standard is expected in the third quarter of 2010.

- 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 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 in the second half of 2010.

- IAS 17 – Leases was assessed primarily in the context of the Company's power purchase arrangements (PPA's). The Company has completed its assessment of its PPA's and will finalize its positions and quantify any impact in the third quarter of 2010. Certain commercial arrangements not currently considered leases may be considered leases under IFRS. In addition, the classification of existing arrangements as either capital or operating leases may change under IFRS.

- IAS 31 – Interests in Joint Ventures sets out the requirements for the accounting of Joint Ventures. This standard will be replaced in the second quarter of 2010. The Company has been monitoring the development of the standard, as the exposure draft proposed equity accounting for certain arrangements currently accounted for by the Company under proportionate consolidation. The Company has completed a review and documented the terms of all these arrangements and will assess the arrangements against the standard when it is issued.

- 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.

  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.

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, by the end of the third quarter of 2010.

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.

*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 not occur until 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 third quarter of 2010 to prepare information for the investor analysts.

The IFRS team will work with the Company's treasury department during the second quarter of 2010 in identifying any issues relating to the extension of the credit facilities.

*Training*

The Company recognizes that training at all levels of the Company is essential to a successful conversion and integration. Accounting staff have attended three training sessions with more planned to occur throughout the conversion process, including a session currently scheduled in June 2010. A training session for the Audit Committee occurred in March 2010 and the Audit Committee will receive regular updates throughout 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. 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 has various financial instruments that are classified for financial reporting purposes as available for sale, held for trading, held to maturity, or loans and receivables. Financial liabilities are classified as either held for trading or other liabilities. Initially, all financial assets and financial liabilities are recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

The Company classifies its cash, cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading, and measures them at fair value. Accounts receivable and long-term loans are classified as loans and receivables and accounts payable and accrued liabilities are classified as other liabilities. Accounts receivable and accounts payable and accrued liabilities are measured at amortized cost and their fair values are not materially different from their carrying values due to their short-term nature.

The classification, carrying amounts and fair values of other financial instruments held at March 31, 2010 are as follows:

| | Carrying amount | | Fair value |
|---|---|---|---|
| (unaudited, $ millions) | Loans and receivables | Other financial liabilities | |
| Other assets | $ 73 | $ - | $ 72 |
| Long-term debt (including current portion) | $ - | $ 1,634 | $ 1,677 |

**Risk management and hedging activities**

The Company is exposed to changes in energy commodity prices, foreign currency exchange rates and interest rates. The Company uses various risk management techniques, including derivative instruments such as forward contracts, fixed-for-floating swaps, and option contracts, to reduce this exposure. These derivative instruments are recorded at fair value on the balance sheet unless the Company elects the fair value exemption for non-financial derivatives that are entered into and continue to be held for the purpose of receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements. The 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 | Total |
|---|---|---|---|---|
| Total derivative instruments net assets (liabilities) as at March 31, 2010 | $ (30) | $ 79 | $ 30 | $ 79 |

**Energy derivatives designated as accounting hedges**

At March 31, 2010, the net fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of $30 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. The net derivative liability is primarily due to a decrease in the forward Alberta natural gas prices relative to the derivative contract prices. Unrealized gains and losses for fair value changes on derivatives that qualify for hedge accounting are recorded in other comprehensive income and reclassified to net income as energy revenues, energy purchases, or fuel as appropriate when realized.

**Energy derivatives not designated as accounting hedges**

At March 31, 2010 the net fair value of energy derivative instruments not designated as hedges for accounting was a net asset of $79 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. This net derivative asset was primarily due to unrealized gains arising from the impact of decreased forward Alberta power prices on the Alberta power portfolio.

At March 31, 2010, the fair value of the Company's forward foreign currency contracts was a net derivative instrument asset of $30 million. The net asset was due to the impact of a strengthening Canadian dollar relative to the U.S. dollar on forward foreign exchange sales contracts used to hedge U.S. dollar denominated revenues. The weighted average fixed exchange rate for contracts outstanding at March 31, 2010 was $1.11 for every U.S. dollar. Unrealized and realized gains and losses on foreign exchange derivatives that are not designated as hedges for accounting purposes are recorded in energy revenues or foreign exchange gains and losses.

All non-financial derivative instruments are measured at fair value unless they are designated as contracts used for the purpose of receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements as defined by accounting standards, or are designated and qualify for hedge accounting. Some of the Company's physical power and natural gas purchase and sales contracts that are used to meet power generation and retail customer requirements were not designated as contracts used in accordance with the Company's expected purchase requirements and therefore are recorded at fair value in the balance sheet.

**Risk management and hedge accounting**

The Company uses various financial and non-financial derivatives primarily for risk management purposes. Unrealized changes in the fair value of financial and non-financial derivatives that either do not qualify for hedge accounting or the Company elects not to apply hedge accounting, and non-financial derivatives that do not qualify for the expected purchase, sale or usage requirements of the contract, are recorded in energy revenues, energy purchases or cost of fuel, as appropriate. The corresponding unrealized changes in the fair value of the associated economically hedged exposures are not recognized in income. Accordingly, derivative instruments that are recorded at fair value can produce volatility in net income as a result of fluctuating forward commodity prices, exchange rates and interest rates which are not offset by the unrealized fair value changes of the exposure being hedged on an economic basis. As a result, accounting gains or losses relating to changes in fair values of derivative instruments do not necessarily represent the underlying economics of the hedging transaction.

**Other comprehensive income**

Changes in the fair value of the effective hedge portion of the financial derivative contracts used to manage the energy portfolio and designated as accounting hedges, are recorded in other comprehensive income. The ineffective portion of the contracts is recorded in net income.

For the period ended March 31, 2010, losses on derivative instruments designated as cash flow hedges, net of income taxes, of $17 million were recorded in other comprehensive income for the effective portion of cash flow hedges, and a realized loss, net of income taxes, of $6 million was reclassified to energy purchases and revenues as appropriate. There was no ineffective portion of cash flow hedges for which unrealized gains or losses were required to be recognized in income. Of the $11 million in net unrealized fair value gains related to derivative instruments designated as cash flow hedges included in accumulated other comprehensive income at March 31, 2010, net losses of $4 million, net of taxes of $1 million are expected to settle and be reclassified to net income over the next twelve months.

## Internal Control over Financial Reporting

There were no changes in the Company's internal controls over financial reporting that occurred during the three months ended March 31, 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) expected timing of commercial operation, expected future generation capacity, project costs and funding of the Quality Wind and Port Dover & Nanticoke Wind projects; (ii) expected contracted price for power under the OPA Feed-in-Tariff relating to the Port Dover & Nanticoke Wind project; (iii) expectations for the Company's and CPILP's sources of capital and use and availability of committed bank credit facilities; (iv) the Company's and CPILP's cash requirements for 2010, including expectations relating to capital expenditures, distributions and dividends; (v) expectations regarding future financial strength and access to and terms of future financings; (vi) expectation about the ability of the Alberta plant portfolio to participate in rising power market opportunities during the time Clover Bar Energy Centre Unit 2 is offline and the impact of Unit 2 being offline on plant availability, operating income and cash flows from operations; (vii) expected timing of when Clover Bar Energy Centre Unit 2 will be brought back online; (viii) expected annual spending for maintenance capital and other capital for the Company as well as expected project completion dates; (ix) expected timing and impact of the two maintenance outages scheduled and the de-rates as a result of the AESO transmission outage in 2010 at the Genesee site on generation output, availability incentive income, operating margin, and funds from operations; (x) expectations regarding CPILP's North Carolina plants enhancement projects and Oxnard turbine replacement project and their completion dates; (xi) expectations about future income and future CPLP and CPILP distributions; (xii) expected impact of transition to IFRS and expected project review completion dates; (xiii) expectations regarding the Company's strategy, including expectations that the long-term contract for the Quality Wind project supports Capital Power's strategy to maintain a balance between contracted and merchant generation; and (xiv) expectations regarding the impact of delays in the finalization of new PPAs for the North Carolina facilities on CPILP's earnings.

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, including those subject to acquired PPAs; (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) the currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; (xviii) ability to obtain necessary regulatory approvals for development projects; (xix) the Company's assessment of capital markets 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; and (xxi) costs of construction and development.

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; 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) the expectations about the timing and impact of the two scheduled maintenance outages at the Genesee site on generation output, availability incentive income, operating margin and funds from operations, have been revised to include the de-rates expected as a result of the transmission outage declared by the AESO; (ii) expectations regarding the ability to manage the exposure to changing electricity prices and participate in rising power market opportunities and expectations regarding plant availability have been revised to include the impact of the outage at Clover Bar Energy Centre Unit 2; and (iii) expectations regarding capital expenditures in 2010 have been revised to reflect expected expenditures for new wind power development projects.

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

### Financial highlights

| (unaudited, $ millions except earnings per share) | Three months ended | | |
|---|---|---|---|
| | March 31, 2010 | Dec 31, 2009 | Sept 30, 2009 |
| Revenues[3] | 499 | 497 | 511 |
| Gross margin[1] | 216 | 216 | 218 |
| Operating margin[1] | 167 | 154 | 169 |
| Net income | 13 | 7 | 14 |
| Earnings per share | $ 0.60 | $ 0.33 | $ 0.64 |
| Fully diluted earnings per share[2] | $ 0.60 | $ 0.30 | $ 0.59 |
| Funds from operations[1] | 112 | 71 | 93 |
| Normalized earnings per share[1] | $ 0.55 | $ 0.18 | $ 0.42 |
| Capital expenditures | 78 | 127 | 108 |
| Long-term debt including current portion | 1,634 | 1,719 | 1,771 |
| Total assets | 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 of revenue and energy purchases by $14 million each. The restatement had no impact on gross margin, operating margin or net income and the presentations for the periods in the table above are consistent.

**Generation volume information**

| (unaudited, GWh) | Three months ended | | |
|---|---|---|---|
| **Electricity generation**[1] | March 31, 2010 | Dec 31, 2009 | Sept 30, 2009 |
| Alberta commercial plants | | | |
| Genesee 3 | 483 | 484 | 470 |
| Joffre | 41 | 73 | 89 |
| Clover Bar Energy Centre 1, 2 and 3[2] | 43 | 9 | 16 |
| Taylor Coulee Chute | - | 2 | 12 |
| Clover Bar Landfill Gas | 10 | 10 | 9 |
| Weather Dancer | - | - | - |
| | 577 | 578 | 596 |
| Alberta contracted plants | | | |
| Genesee 1 | 813 | 618 | 837 |
| Genesee 2 | 825 | 817 | 801 |
| | 1,638 | 1,435 | 1,638 |
| Ontario and British Columbia contracted plants | | | |
| Kingsbridge 1 | 26 | 32 | 14 |
| Miller Creek | 7 | 14 | 47 |
| Brown Lake | 13 | 15 | 11 |
| | 46 | 61 | 72 |
| CPILP plants | 1,268 | 1,407 | 1,228 |
| **Total** | **3,529** | **3,481** | **3,534** |

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

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

| (unaudited) | Three months ended | | |
|---|---|---|---|
| **Generation plant availability**[1] | March 31, 2010 | Dec 31, 2009 | Sept 30, 2009 |
| Alberta commercial plants | | | |
| Genesee 3 | 100% | 99% | 97% |
| Joffre | 100% | 94% | 96% |
| Clover Bar Energy Centre 1, 2 and 3[2] | 72% | 98% | 96% |
| Taylor Coulee Chute | 98% | 66% | 100% |
| Clover Bar Landfill Gas | 96% | 94% | 90% |
| Weather Dancer | 83% | 0% | 55% |
| | 98% | 97% | 96% |
| Alberta contracted plants | | | |
| Genesee 1 | 99% | 74% | 100% |
| Genesee 2 | 99% | 97% | 95% |
| | 99% | 85% | 97% |
| Ontario and British Columbia contracted plants | | | |
| Kingsbridge 1 | 99% | 100% | 99% |
| Miller Creek | 37% | 97% | 88% |
| Brown Lake | 97% | 99% | 97% |
| | 71% | 99% | 94% |
| CPILP plants[3] | 95% | 92% | 93% |
| **Average**[3] | **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 Unit 2 and Unit 3 as of their commercial operation dates, 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.

**Factors impacting quarterly financial results**

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. In addition, net income is affected by changes in the fair value of the Company's derivative power and natural gas contracts, natural gas held for trading and foreign exchange contracts.

**Results by Plant Category**

| (unaudited, $ millions) | Three months ended March 31, 2010 | Dec 31, 2009 | Sept 30, 2009[2] |
|---|---|---|---|
| **Revenues** | | | |
| Alberta commercial plants and portfolio optimization | $ 235 | $ 248 | $ 238 |
| Alberta contracted plants | 72 | 61 | 70 |
| Ontario/British Columbia contracted plants | 3 | 4 | 4 |
| CPILP plants | 139 | 130 | 123 |
| Other portfolio activities | 43 | 40 | 23 |
| Inter-plant category transaction eliminations | (10) | (9) | (10) |
| | 482 | 474 | 448 |
| Unrealized fair value changes in derivative instruments and natural gas inventory held for trading | | | |
| - CPLP | 12 | 15 | 30 |
| - CPILP | 5 | 8 | 33 |
| | 17 | 23 | 63 |
| | **$ 499** | **$ 497** | **$ 511** |
| **Gross margin[1]** | | | |
| Alberta commercial plants and portfolio optimization | $ 65 | $ 53 | $ 50 |
| Alberta contracted plants | 59 | 48 | 58 |
| Ontario/British Columbia contracted plants | 3 | 4 | 4 |
| CPILP plants | 77 | 74 | 77 |
| Other portfolio activities | 15 | 12 | 8 |
| Inter-plant category transaction eliminations | (9) | (9) | (8) |
| | 210 | 182 | 189 |
| Unrealized fair value changes in derivative instruments and natural gas inventory held for trading | | | |
| - CPLP | 9 | 26 | 16 |
| - CPILP | (3) | 8 | 13 |
| | 6 | 34 | 29 |
| | **$ 216** | **$ 216** | **$ 218** |
| **Operating margin[1]** | | | |
| Alberta commercial plants and portfolio optimization | $ 55 | $ 39 | $ 41 |
| Alberta contracted plants | 46 | 27 | 47 |
| Ontario/British Columbia contracted plants | 2 | 3 | 3 |
| CPILP plants | 53 | 47 | 48 |
| Other portfolio activities | 5 | 4 | 2 |
| Inter-plant category transaction eliminations | - | - | (1) |
| | 161 | 120 | 140 |
| Unrealized fair value changes in derivative instruments and natural gas inventory held for trading | | | |
| - CPLP | 9 | 26 | 16 |
| - CPILP | (3) | 8 | 13 |
| | 6 | 34 | 29 |
| | **$ 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 first quarter operating margin**

The Company's plant availability increased to 96% in the first quarter of 2010 from 92% in the fourth quarter of 2009, primarily due to an eighteen-day scheduled maintenance outage at Genesee 1 in the fourth quarter.

Revenues for the Alberta commercial plants and portfolio optimization reflect the impact of decreased Alberta power prices on the pricing for the supply of electricity to EPCOR's RRT customers and on generation sales to the Alberta Balancing Pool. In addition, generation sales from the acquired PPAs were lower as a result of the sale of the remaining interest in the Battle River PPA in January 2010. These decreases were partly offset by gains on the settlement of merchant derivative sell contracts in the period as a result of decreased forward Alberta power prices.

The increase in merchant trading of derivative sell contracts in the period had a favourable impact on gross margin and operating margin for the Alberta commercial plant category. The realized price for the portfolio in the first quarter of 2010 was $67/MWh which was $26/MWh higher than the average Alberta power price for the period. Similar to the fourth quarter of 2009, a substantial portion of the portfolio was sold forward at fixed prices in the first quarter of 2010. This also contributed to a realized price for the portfolio in excess of the average spot price for the quarter.

The Alberta contracted plants operated in line with management's expectations. Compared to the previous quarter, the quarter-over-quarter increase in revenues and gross margin of $11 million and operating margin of $19 million were due to the scheduled maintenance outage at Genesee 1 in the fourth quarter as discussed under Factors Impacting the 2009 Fourth Quarter Operating Margin.

The increase in CPILP revenues and gross margin was primarily due to gains on settlement of foreign exchange contracts. The operating margin was favourably impacted by fewer maintenance overhauls in the first quarter of 2010.

The changes in the fair value of CPLP's derivative power and natural gas contracts increased revenues in the first quarter of 2010 primarily due to the impact of decreased forward prices on derivative sell contracts. This increase in revenues was partly offset by unrealized fair value losses included in energy purchases resulting from the impact of decreased forward prices on derivative power and natural gas buy contracts. The increase in gross margin and operating margin for fair value adjustments also include decreases in the fair value of natural gas derivative buy contracts expiring in the near term due to decreased forward natural gas prices for the corresponding term.

The increase in CPILP's revenue for fair value changes in the first quarter of 2010 reflects changes in the fair value of its foreign exchange contracts resulting from decreases in the forward prices for U.S. dollars relative to Canadian dollars. The gross margin and operating margin decreased as a result of fair value losses on CPILP's natural gas supply contracts due to decreased forward natural gas prices.

**Factors impacting the 2009 fourth quarter operating margin**

The Company's plant availability decreased to 92% in the fourth quarter of 2009 from 95% in the third quarter of 2009, primarily due to an eighteen-day scheduled maintenance outage at Genesee 1 in the fourth quarter.

Revenues for the Alberta commercial plants and portfolio optimization reflect an increase in sales volumes for wholesale customers and for the supply to EPCOR's RRT customers due to increased demand in the winter season. In addition, the decrease in Alberta power prices in the quarter resulted in gains on the settlement of merchant derivative sell contracts in the period.

The increase in wholesale sales volumes had a favourable impact on gross margin and operating margin for the Alberta commercial plant category. The realized price for the portfolio for the fourth quarter of 2009 was $57/MWh which was $11/MWh higher than the average Alberta power price for the period as a substantial portion of the portfolio was sold forward at fixed contract prices. Operating costs for the fourth quarter of 2009 included increases in acquired PPA capacity payments in accordance with the plant operators' cost schedules and escalation factors and included a retroactive adjustment of $3 million. Environmental charges under the terms of the acquired PPAs also increased in the fourth quarter due to increases in $CO_2$ emissions at the Sundance plant and an increased cost per tonne for these charges.

The impact of the planned outage at Genesee 1 on the fourth quarter results for the Alberta contracted plants was in line with management's expectations. Under the terms of the PPA, penalty payments were incurred during the outage, and compensation from the Alberta Balancing Pool for variable costs was reduced due to the decrease in generation resulting from the outage. These factors reduced revenue by approximately $6 million. Operating margin was also reduced by approximately $10 million of maintenance costs for the outage. Increased operational costs for environmental studies further reduced the operating margin for the Alberta contracted plants in the fourth quarter of 2009.

Revenues for the CPILP plants for the fourth quarter of 2009 reflected higher pricing under the terms of the power sales contracts for the Ontario plants during the winter months and higher generation at the Curtis Palmer plant due to water flows which are higher in winter than summer. These favourable factors were partly offset by lower revenue from the California facilities due to lower pricing in the winter months under the terms of the PPAs and lower generation from the North Carolina facilities which in periods of low natural gas prices are not as economical to run as competitive natural gas-fired power generation plants. The impact of lower pricing at the California plants was partly offset by higher generation volumes from these plants. The gross margin and operating margin were unfavourably impacted by increased fuel expense for the higher generation from the California plants.

Revenues, gross margin and operating margin for other portfolio activities in the fourth quarter of 2009 reflected an increase in natural gas sales volumes due to increased demand from end-use customers in the winter months.

The changes in the fair value of CPLP's derivative contracts increased revenues in the fourth quarter of 2009 primarily due to the impact of decreased forward prices on derivative sell contracts. The increase in gross margin and operating margin for fair value adjustments also include increases in the fair value of natural gas derivative buy contracts expiring in the near term due to decreased forward natural gas prices for the corresponding term.

The increase in CPILP's revenue, gross margin and operating margin for fair value changes in the fourth quarter of 2009 reflects an increase in the fair value of its foreign exchange contracts resulting from strengthening future prices for the Canadian dollar relative to the U.S. dollar.

**Factors impacting the 2009 third quarter operating margin**

There were no major plant outages in the third quarter of 2009 and the average availability for all plants was 95%. Alberta power prices averaged $49/MWh and the Company's average realized price for the Alberta commercial plants and portfolio optimization was $54/MWh as the portfolio was substantially sold forward at fixed contract prices. Results for the Alberta, Ontario and British Columbia contracted plants were in line with expectations. Revenues for the CPILP plants reflected normal seasonal variances including lower pricing for the Ontario plants and lower water volumes at the hydro facilities, partly offset by summer performance bonuses for the California plants.

The fair value of CPLP's derivative instruments and natural gas inventory held for trading increased $16 million in the third quarter primarily due to the impact of decreased forward electricity prices on the portfolio of electricity derivative instruments.

The fair value of CPILP's foreign exchange contracts increased $33 million in the third quarter 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 $20 million due decreased forward prices for natural gas. On July 31, 2009, CPILP designated certain of its natural gas supply contracts as hedges for accounting purposes. Therefore, the $20 million fair value loss primarily relates to the period from July 1, 2009 to July 31, 2009.

**Factors impacting consolidated expenses**

| (unaudited, $millions) | Three months ended | | |
|---|---|---|---|
| | March 31, 2010 | Dec 31, 2009 | Sept 30, 2009 |
| Indirect administration | 26 | 37 | 27 |
| Depreciation, amortization and asset retirement accretion | 46 | 48 | 44 |
| Foreign exchange losses | 1 | 1 | 3 |
| Net financing expenses | 18 | 17 | 17 |
| Income taxes (reductions) | - | 12 | (2) |
| Non-controlling interests | | | |
| - CPLP | 76 | 24 | 44 |
| - CPILP | 12 | 6 | 20 |
| - Preferred share dividends paid by CPI Preferred Equity Ltd. | 3 | 2 | 2 |

The quarter-over-quarter changes in consolidated expenses were primarily due to the following:

- Indirect administration expenses were lower in the first quarter of 2010 primarily due to lower business development costs. Indirect administration expenses in the fourth quarter of 2009, included an impairment loss of $4 million on a venture capital investment, an increase in information technology costs of $2 million, higher transition costs relating to the Reorganization and higher employee stock option costs.
- Depreciation expense in the first quarter of 2010 reflected lower amortization of the fair value increments for capital assets recognized in the purchase price allocation for the Reorganization. Depreciation expense for the fourth quarter of 2009 included losses incurred on the disposal of assets and depreciation for Clover Bar Energy Centre Units 2 and 3 commencing September 1, 2009 and December 16, 2009, respectively.
- Foreign exchange expense reflects the impact of a weakening U.S. dollar relative to the Canadian dollar on the translation of the Company's U.S. monetary assets and liabilities that are not included in CPILP's self sustaining operations. The translation gains and losses relating to CPILP's U.S. operations are included in other comprehensive income rather than the income statement as the functional currency for those operations is U.S. dollars.
- Income taxes for the first quarter of 2010 included a net recovery adjustment for the impact of changes in income tax laws on future income tax assets and liabilities. An income tax recovery for the recognition of a net future income tax asset for a $10 million out-of-period adjustment associated with CPILP's interest in Primary Energy Recycling Holdings LLC was recognized in the third quarter of 2009. In the fourth quarter of 2009, this income tax recovery was reclassified and included in the acquisition of assets from EPCOR since it related to periods prior to July 1, 2009.
- The increase in non-controlling interests in the first quarter of 2010 reflected higher income for the period including the gain on the sale of the remaining interest in the Battle River PPA.

## 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 | | | |
| --- | --- | --- | --- | --- |
| | March 31, 2010 | Dec 31, 2009 | Sept 30, 2009 | June 30, 2009 |
| Share price | | | | |
| High | $23.00 | $21.78 | $22.39 | $23.00 |
| Low | $20.97 | $18.95 | $19.50 | $22.00 |
| Close | $22.50 | $21.37 | $19.75 | $22.35 |
| Volume traded (millions) | 7.6 | 6.5 | 12.1 | 5.8 |

As at April 30, 2010, the Company had 21.75 million common shares outstanding, 56.625 million special voting shares outstanding and one special limited voting share outstanding. The weighted average number of shares outstanding for the three months ended March 31, 2010 was 78.375 million. All of the outstanding special voting shares and the outstanding special limited voting share are held indirectly by EPCOR.

As at April 30, 2010, CPLP had 21.75 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 April 30, 2010, CPILP had 54.7 million limited partnership units outstanding and 16.5 million of such units, representing 30.2% of the outstanding limited partnership units, were held by CPI Investments Inc. EPCOR held 51 Class A Shares of CPI Investments Inc. representing 51% of the votes and CPLP held 49 Class B Shares of CPI Investments Inc. representing 49% of the votes. CPLP had an effective 100% economic interest in CPI Investments Inc.

## Additional Information

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

# CAPITAL POWER CORPORATION

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

| | Three months ended March 31, 2010 |
|---|---|
| Revenues | $ 499 |
| Energy purchases and fuel | 283 |
| | 216 |
| Operations, maintenance and direct administration | 44 |
| Indirect administration | 26 |
| Property taxes | 5 |
| Depreciation, amortization and asset retirement accretion | 46 |
| Foreign exchange losses | 1 |
| Gain on sale of power syndicate agreement (note 4) | (28) |
| Net financing expenses | 18 |
| | 112 |
| Income before income tax expense and non-controlling interests | 104 |
| Income tax expense (note 6) | - |
| Income before non-controlling interests | 104 |
| Non-controlling interests (note 5) | 91 |
| Net income | $ 13 |
| Earnings per share | |
| Basic | $ 0.60 |
| Diluted | 0.60 |
| Weighted average number of common shares outstanding | |
| Basic | 21,750,000 |
| Diluted | 78,375,000 |

See accompanying notes to consolidated financial statements.

# CAPITAL POWER CORPORATION

Consolidated Balance Sheets
(Unaudited, in millions of dollars)

| | March 31, 2010 | December 31, 2009 |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents | $ 65 | $ 52 |
| Accounts receivable | 212 | 275 |
| Income taxes recoverable | 6 | 29 |
| Inventories | 56 | 58 |
| Prepaid expenses | 6 | 8 |
| Derivative instruments assets (note 7) | 174 | 146 |
| Future income tax assets (note 6) | 12 | 2 |
| Assets held for sale (note 4) | - | 36 |
| | 531 | 606 |
| Property, plant and equipment | 3,267 | 3,242 |
| Power purchase arrangements | 506 | 528 |
| Contract and customer rights and other intangible assets | 180 | 184 |
| Derivative instruments assets (note 7) | 155 | 155 |
| Future income tax assets (note 6) | 59 | 61 |
| Goodwill | 138 | 140 |
| Other assets | 116 | 120 |
| | $ 4,952 | $ 5,036 |
| Liabilities and Shareholders' Equity | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | $ 280 | $ 339 |
| Other current liabilities | 7 | 8 |
| Derivative instruments liabilities (note 7) | 132 | 108 |
| Future income tax liabilities (note 6) | 19 | 21 |
| Current portion of long-term debt | 247 | 247 |
| | 685 | 723 |
| Long-term debt | 1,387 | 1,472 |
| Derivative instruments liabilities (note 7) | 118 | 102 |
| Other non-current liabilities | 107 | 109 |
| Future income tax liabilities (note 6) | 85 | 95 |
| | 2,382 | 2,501 |
| Non-controlling interests (note 5) | 2,075 | 2,046 |
| Shareholders' equity: | | |
| Share capital | 477 | 477 |
| Contributed surplus | 2 | 2 |
| Retained earnings | 13 | 7 |
| Accumulated other comprehensive income | 3 | 3 |
| Retained earnings and accumulated other comprehensive income | 16 | 10 |
| | 495 | 489 |
| Commitments (note 9) | | |
| Subsequent events (note 12) | | |
| | $ 4,952 | $ 5,036 |

See accompanying notes to consolidated financial statements.

# CAPITAL POWER CORPORATION

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

| | Three months ended March 31, 2010 |
|---|---|
| Share capital: | |
| Balance, beginning of period | $ 477 |
| Balance, end of period | 477 |
| Contributed surplus: | |
| Balance, beginning of period | 2 |
| Balance, end of period | 2 |
| Retained earnings: | |
| Balance, beginning of period | 7 |
| Net income | 13 |
| Common share dividends | (7) |
| Balance, end of period | 13 |
| Accumulated other comprehensive income: | |
| Balance, beginning of period | 3 |
| Other comprehensive income | - |
| Balance, end of period | 3 |
| Total shareholders' equity, end of period | $ 495 |

See accompanying notes to consolidated financial statements.

# CAPITAL POWER CORPORATION

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

| | Three months ended March 31, 2010 |
|---|---|
| Net income | $ 13 |
| Other comprehensive income (loss), net of income taxes: | |
| Changes in gains and losses on derivative instruments designated as cash flow hedges[1] | (17) |
| Reclassification of losses on derivative instruments designated as cash flow hedges to net income[2] | 6 |
| Unrealized loss in self-sustaining foreign operations[3] | (20) |
| Non-controlling interests[4] (note 5) | 31 |
| | - |
| Comprehensive income | $ 13 |

[1] For the three months ended March 31, 2010, net of income tax recoveries of $8.

[2] For the three months ended March 31, 2010, net of reclassification of income tax recovery of $1.

[3] For the three months ended March 31, 2010, net of income tax expense of $4.

[4] For the three months ended March 31, 2010, net of income tax expense of nil.

See accompanying notes to consolidated financial statements.

# CAPITAL POWER CORPORATION

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

| | Three months ended March 31, 2010 |
|---|---|
| **Operating activities:** | |
| Net income | $ 13 |
| Adjustments to reconcile net income to cash flows from operating activities: | |
| Depreciation, amortization and asset retirement accretion | 46 |
| Gain on sale of power syndicate agreement (note 4) | (28) |
| Non-controlling interests in CPILP and CPLP (note 5) | 88 |
| Fair value changes on derivative instruments | (7) |
| Unrealized foreign exchange losses | 2 |
| Future income taxes | (1) |
| Other | (1) |
| | 112 |
| Change in non-cash operating working capital | 18 |
| | 130 |
| **Investing activities:** | |
| Property, plant and equipment and other assets | (78) |
| Proceeds on sale of power syndicate agreement (note 4) | 64 |
| Other | 2 |
| | (12) |
| **Financing activities:** | |
| Repayment of long-term debt | (69) |
| Distributions to non-controlling interests | (28) |
| Common share dividends paid | (7) |
| | (104) |
| Foreign exchange losses on cash held in a foreign currency | (1) |
| Increase in cash and cash equivalents | 13 |
| Cash and cash equivalents, beginning of period | 52 |
| Cash and cash equivalents, end of period | $ 65 |
| **Supplementary cash flow information:** | |
| Interest paid net of interest received | $ 23 |
| Income taxes recovered net of income taxes paid | (8) |

See accompanying notes to consolidated financial statements.

**1. Basis of presentation:**

These unaudited interim consolidated financial statements 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 formed on May 29, 2009, and did not have any results from operations or significant cash flows in the period from May 29 to June 30, 2009. Accordingly, there is no comparative statement of income, statement of changes in shareholders' equity, statement of comprehensive income and statement of cash flows for the period ended March 31, 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 three months ended March 31, 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 three months ended March 31, 2010 is nil.

(Unaudited, tabular amounts in millions of dollars)

## 5. Non-controlling interests:

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

| | Three months ended March 31, 2010 |
|---|---|
| Non-controlling interests in CPILP | $ 12 |
| Non-controlling interests in CPLP | 76 |
| Preferred share dividends paid by subsidiary company | 3 |
| | $ 91 |

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

| | March 31, 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 | (34) | (34) |
| Distributions to non-controlling interests | (17) | (33) |
| Issue of CPILP units to non-controlling interests | 7 | 3 |
| Non-controlling interests in CPILP, end of period | 313 | 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 | 76 | 68 |
| Other comprehensive income attributable to non-controlling interests | 3 | 17 |
| Distributions to non-controlling interests | (18) | (36) |
| Non-controlling interests in CPLP, end of period | 1,542 | 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 |
| | $ 2,075 | $ 2,046 |

(Unaudited, tabular amounts in millions of dollars)

**6. Income taxes:**

| | Three months ended March 31, 2010 |
|---|---|
| Future income taxes | $ (14) |
| Current income taxes | 14 |
| | $ - |

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

| | Three months ended March 31, 2010 |
|---|---|
| Income before income taxes and non-controlling interests | $ 104 |
| Statutory income tax rates | 28.0% |
| Income taxes at statutory rate | 29 |
| Increase (decrease) resulting from: | |
| Taxable income attributable to non-controlling interests | (22) |
| Change in valuation allowance | 1 |
| Non-taxable amounts | (1) |
| Adjustment for enacted changes in income tax laws and rates and other tax rate differences | (7) |
| | $ - |

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:

| | March 31, 2010 | December 31, 2009 |
|---|---|---|
| Property, plant and equipment – differences in net book value and tax bases | $ (98) | $ (102) |
| Losses carried forward | 86 | 79 |
| Power purchase arrangements | (24) | (27) |
| Asset retirement obligations | 13 | 13 |
| Cumulative eligible capital | 12 | 12 |
| Deferred income from partnerships | (10) | (19) |
| Derivative Instruments | (1) | (5) |
| Other | (11) | (4) |
| Net future income tax liabilities | $ (33) | $ (53) |
| **Presented on the balance sheet as follows:** | | |
| Current assets | $ 12 | $ 2 |
| Non-current assets | 59 | 61 |
| Current liabilities | (19) | (21) |
| Non-current liabilities | (85) | (95) |
| | $ (33) | $ (53) |

(Unaudited, tabular amounts in millions of dollars)

## 7. 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.

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

| | March 31, 2010 | | | |
|---|---|---|---|---|
| | Energy | | Foreign exchange | |
| | Cash flow hedges | Non-hedges | Non-hedges | Total |
| Derivative instruments assets: | | | | |
| Current | $ 22 | $ 145 | $ 7 | $ 174 |
| Non-current | 38 | 89 | 28 | 155 |
| Derivative instruments liabilities: | | | | |
| Current | (30) | (100) | (2) | (132) |
| Non-current | (60) | (55) | (3) | (118) |
| Net fair value | $ (30) | $ 79 | $ 30 | $ 79 |
| Net notional buys (sells): | | | | |
| Megawatt hours of electricity (millions) | (4) | (4) | | |
| Gigajoules of natural gas (millions) | 44 | 6 | | |
| Foreign currency (U.S. dollars) | | | $ (365) | |
| Range of contract terms in years | 0.1 to 6.8 | 0.1 to 4.7 | 0.1 to 5.7 | |

| | December 31, 2009 | | | |
|---|---|---|---|---|
| | Energy | | Foreign exchange | |
| | Cash flow 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) | |
| Range of contract terms in years | 0.1 to 7.0 | 0.1 to 4.8 | 0.1 to 6.0 | |

**7. Derivative instruments and hedge accounting, continued:**

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

| | Three months ended March 31, 2010 | |
|---|---|---|
| | Unrealized gains (losses) | Realized gains (losses) |
| Energy cash flow hedges | $ (17) | $ (7) |
| Energy non-hedges | - | 11 |
| Foreign exchange non-hedges | 5 | 3 |

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 months ended March 31, 2010, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was nil. Net losses of $4 million, net of income taxes of $1 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.

**8. 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.

**8. Risk management, continued:**

**Market risk, continued**

*Commodity price risk, continued*

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 March 31, 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 7.

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 March 31, 2010, there is a 99% probability that unfavorable daily market variations would not reduce the twelve month portfolio by more than $3 million.

(Unaudited, tabular amounts in millions of dollars)

**8. Risk management, continued:**

**Liquidity risk**

As at March 31, 2010, the Company had undrawn and committed bank credit facilities, including operating lines of credit and demand facilities, of $1,381 million (December 31, 2009 - $1,294 million), of which $660 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. The Company's subsidiary, CPILP, has a Canadian shelf prospectus, which expires in August 2010, under which it may raise up to $1 billion in partnership units or debt securities, of which a maximum of $600 million can be medium-term notes. As at March 31, 2010, CPILP has not drawn on the shelf prospectus (December 31, 2009 - nil). In the three months ended March 31, 2010, CPC has issued a Canadian shelf prospectus, which expires in April 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 March 31, 2010, CPC has not drawn on the shelf prospectus. In the three months ended March 31, 2010, the Company's subsidiary, CPLP, has issued a Canadian shelf prospectus, which expires in April 2012, under which it may raise up to $1 billion in medium-term notes. As at March 31, 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 March 31, 2010:

| | Due within 1 year | Due between 1 and 2 years | 2 and 3 years | 3 and 4 years | 4 and 5 years | Due after more than 5 years | Total contractual cash flows |
|---|---|---|---|---|---|---|---|
| **Non-derivative financial liabilities**: | | | | | | | |
| Long-term debt | $ 247 | $ 304 | $ 69 | $ 20 | $ 207 | $ 799 | $ 1,646 |
| Interest payments on long-term debt | 94 | 84 | 66 | 64 | 57 | 363 | 728 |
| Accounts payable and accrued liabilities [1] | 257 | - | - | - | - | - | 257 |
| Other current liabilities | 7 | - | - | - | - | - | 7 |
| Loan commitments | 6 | - | - | - | - | - | 6 |
| **Derivative financial liabilities:** | | | | | | | |
| Net forward foreign exchange contracts | 1 | 1 | 1 | 1 | 1 | - | 5 |
| Net commodity contracts-for-differences | 80 | 45 | 4 | - | - | - | 129 |
| Total | $ 692 | $ 434 | $ 140 | $ 85 | $ 265 | $ 1,162 | $ 2,778 |

[1] Excluding accrued interest on long-term debt of $23 million.

(Unaudited, tabular amounts in millions of dollars)

**9. Commitments:**

During the three months ended March 31, 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 megawatt (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.

**10. Guarantees:**

The Company has issued letters of credit for $99 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 March 31, 2010, EPCOR continues to have outstanding parental guarantees on behalf of Capital Power totaling $1,169 million (December 31, 2009 - $1,295 million) related to subsidiaries of Capital Power.

**11. 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 March 31, 2010 | | | |
|---|---|---|---|---|
| | Canada | U.S. | Inter-area eliminations | Total |
| Revenues - external | $ 417 | $ 82 | $ - | $ 499 |
| Inter-area revenues | 4 | 4 | (8) | - |
| Total revenues | $ 421 | $ 86 | $ (8) | $ 499 |
| Property, plant and equipment | $ 2,772 | $ 495 | $ - | $ 3,267 |
| Goodwill | $ 104 | $ 34 | $ - | $ 138 |

**12. Subsequent events:**

On April 8, 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 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.

**13. 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.