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For release: March 8, 2011

# Capital Power reports fourth quarter and year-end 2010 results

**EDMONTON, Alberta** – Capital Power Corporation ("Capital Power", or the "Company") (TSX: CPX) today released its results for the quarter and year ended December 31, 2010. Normalized net income attributable to common shareholders, after adjusting for one-time items and fair value adjustments, was $6 million, or $0.26 per share, in the fourth quarter of 2010, compared with $4 million, or $0.18 per share, in the comparable 2009 period. Funds from operations, excluding non-controlling interests in CPILP, totaled $62 million in the 2010 period, up 19% from $52 million in 2009.

For the full year ended December 31, 2010, normalized net income attributable to common shareholders was $31 million or $1.40 per share, with funds from operations excluding non-controlling interests in CPILP, of $263 million.

"We're pleased with our results in the fourth quarter of 2010, which slightly exceeded management's expectations," said Brian Vaasjo, President and CEO of Capital Power. "For the year as a whole, our results were solid, representing a good performance in a difficult pricing environment. Generation volume in our facilities excluding CPILP plants increased 3.5%, with average availability at 90%, despite the six-month shut down at Clover Bar Energy Centre's Unit 2."

"In line with our stated objective of reaching 10,000 megawatts (MW) of capacity by the year 2020, 2010 was characterized by a number of new growth initiatives," added Mr. Vaasjo. "This included the acquisition of Island Generation and the initiation of two wind power projects, totaling 522 MW of capacity. We built on this with the announcement last month of the pending acquisition of the Tiverton, Rhode Island and Rumford, Maine gas-fired facilities, and the announcement today of the pending acquisition of the Bridgeport Energy facility in Connecticut, which together represent more than 1,000 MW of combined cycle natural gas fired generation capacity in the New England region. Including these acquisitions, approximately 2,000 MW of new production has been added or placed into development since our initial public offering in mid-2009."

| **Operational and Financial Highlights**(1) | **Three months ended December 31** (unaudited) | | **Twelve months ended December 31** (unaudited) | |
|---|---|---|---|---|
| *(millions of dollars except per share and operational amounts)* | **2010** | **2009** | **2010** | **2009** (3) |
| Electricity generation (GWh) | **3,867** | 3,481 | **14,218** | 13,857 |
| Generation plant availability (excluding CPILP plants) (%) | **91%** | 92% | **90%** | 96% |
| Revenues | **440** | 497 | **1,760** | 2,158 |
| Gross margin(2) | **203** | 216 | **768** | 883 |

| | | | | |
|---|---|---|---|---|
| Operating margin(2) | **122** | 154 | **520** | 655 |
| Normalized net income attributable to common shareholders (2) | **6** | 4 | **31** | N/A |
| Normalized earnings per share(2) | **$0.26** | $0.18 | **$1.40** | N/A |
| Net income (loss) attributable to common shareholders | **(1)** | 7 | **11** | 51 |
| Earnings (loss) per share | **$(0.04)** | $0.33 | **$0.50** | N/A |
| Dividends declared per share | **$0.315** | $0.315 | **$1.26** | N/A |
| Funds from operations(2)(4) | **82** | 75 | **354** | N/A |
| Funds from operations excluding non-controlling interests in CPILP(2)(4) | **62** | 52 | **263** | N/A |
| Capital expenditures | **52** | 122 | **337** | N/A |

(1) The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the audited Consolidated Financial Statements for the year ended December 31, 2010.
(2) Gross margin, Operating margin, Normalized net income attributable to common shareholders, 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 March 8, 2011.
(3) Financial highlights for the year ended December 31, 2009 are unaudited pro forma consolidated financial information included in the Pro forma Consolidated Financial Information section in the Company's Management's Discussion and Analysis dated March 8, 2011. Certain financial highlights are not applicable (N/A) for the year ended December 31, 2009 as the unaudited pro forma financial information does not include a balance sheet, a statement of cash flows or earnings per share.
(4) Amounts for previous quarters have been reclassified to conform to the presentation adopted in the fourth quarter of 2010.

## Corporate Updates

**$221 million secondary offering of Capital Power common shares by EPCOR**

In December 2010, a subsidiary of EPCOR exchanged 9,209,000 of its exchangeable limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9,209,000 common shares of Capital Power to the public pursuant to a secondary offering at $24.00 per common share. Capital Power did not receive any of the approximate $221 million of proceeds from EPCOR's sale of common shares. This transaction reduced EPCOR's ownership interest in CPLP to approximately 60.5% from its initial interest of 72.2% and reduced EPCOR's indirect ownership of the common shares of Capital Power on a fully diluted basis to 60.5% from 72.2%. EPCOR has advised the Company that it intends to eventually sell all or a substantial number of its common shares underlying its exchangeable partnership units of CPLP, subject to market conditions and its requirement for capital in the future.

The common shares were offered in all provinces of Canada by way of a prospectus supplement to a base shelf prospectus of Capital Power. The offering was also extended to qualified institutional buyers in the U.S. pursuant to the exemptions from registration provided by Rule 144A of the Securities Act of 1933, as amended, and internationally where permitted.

**$125 million offering of 4.60% Cumulative Rate Reset Preferred Shares**

On December 16, 2010, Capital Power Corporation issued 5 million Cumulative Rate Reset Preference Shares, Series 1 (Series 1 Shares) at $25 per share for aggregate gross proceeds of $125 million less issue costs of $4 million. The net proceeds were lent to CPLP pursuant to a subordinated debt agreement. CPLP used the funds to repay a portion of the balance outstanding under its credit facilities which was used to fund the acquisition of Island Generation and for general corporate purposes.

The Series 1 Shares will pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last day of March, June, September and December of each year, as and when declared by the Board of Directors of Capital Power, for the initial five-year period ending December 31, 2015. The first quarterly dividend of $0.3308 per share is expected to be paid on March 31, 2011. The dividend rate will be reset on December 31, 2015 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%. The Series 1 Shares are redeemable by Capital Power, at its option, on December 31, 2015 and on December 31 of every fifth year thereafter.

Holders of Series 1 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 2 (Series 2 Shares), subject to certain conditions, on December 31, 2015 and on December 31 of every fifth year thereafter. Holders of Series 2 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.17%, as and when declared by the Board of Directors of Capital Power.

Standard & Poor's, a division of the McGraw Hill Companies, Inc. (S&P) has assigned a rating of P-3 (High) for the Series 1 Shares and DBRS Limited (DBRS) has assigned a rating of Pfd-3 (low) for the Series 1 Shares.

**$300 million debt offering**

On November 16, 2010, CPLP completed a public offering in Canada of unsecured medium term note debentures with a principal amount of $300 million. The notes have a coupon rate of 5.276% and mature on November 16, 2020. The net proceeds of the offering were used to finance a portion of the purchase price for Island Generation, repay amounts owing under the Company’s credit facilities and for general corporate purposes.

The notes have been rated BBB by S&P and BBB by DBRS.

**Acquisition of Island Generation Facility**

CPLP’s acquisition of Island Generation from Kelson Canada Inc. closed on October 19, 2010. Island Generation is a 275 MW gas-fired combined cycle power plant at Campbell River, British Columbia. The Company initially financed the purchase price of $205 million with funds drawn on credit facilities.

Island Generation is fully contracted to April 2022 under an electricity purchase arrangement where BC Hydro is responsible for the fuel supply to the facility. Commissioned in 2002, Island Generation is consistent with Capital Power’s fleet of young assets that deploy efficient technologies. Based on the terms of the energy purchase arrangement, the Island Generation facility is expected to be modestly and immediately accretive to earnings, and more significantly accretive to cash flow.

**Review of strategic alternatives for CPILP**

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

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

The process to review strategic alternatives is expected to continue into the second quarter of 2011. During this period it is business as usual for CPILP and Capital Power Corporation and it is anticipated that CPILP will continue to provide the same amount of monthly distributions to its unitholders, and maintain the same investor proposition that it offers today. Capital Power Corporation, through wholly owned subsidiaries, will continue to manage CPILP assets.

### New wind projects

On March 11, 2010, the Company's Quality Wind project was selected by BC Hydro for the award of an Energy Purchase Agreement, which was signed by the two parties in April 2010. The project is for the development of a 142 MW wind farm near Tumbler Ridge, British Columbia and is expected to cost approximately $455 million. The Environmental Assessment Certificate for the project was received from the Government of British Columbia in July 2010 and construction of the project commenced in the fourth quarter of 2010. The Company anticipates that the plant will commence commercial operation by the end of the fourth quarter of 2012, ahead of the deadline (second quarter of 2013) for power from the plant to be on the grid as required by the Energy Purchase Agreement.

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 through the OPA's FIT program. The 105 MW project will be located 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. The contract to sell power has since been signed and under the terms of the OPA's FIT 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% of the contract price will escalate annually at inflation throughout the 20-year contract term. Construction of the Port Dover & Nanticoke Wind project is subject to regulatory approvals, including Ontario's Renewable Energy Approval process which is currently in progress for the project.

The Company selected Vestas (NASDAQ OMX Copenhagen:VWS) for the supply and maintenance of wind turbines for both projects, as well as for the Kingsbridge II project in Ontario.

### 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 gain of $28 million. 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.

### Corporate Responsibility Report

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

## Subsequent Events

### Acquisition of two New England power plants

In February 2011, CPLP entered into an agreement to acquire two generating facilities from Brick Power Holdings LLC, one facility located in Tiverton, Rhode Island (Tiverton) and one facility located in Rumford, Maine (Rumford). Both plants are natural gas-fired combined cycle power generation facilities serving the New England region in the U.S. Northeast, and have a maximum combined capacity of 549 MW.

The transaction is expected to close in April 2011, subject to regulatory approvals and satisfaction of other customary closing conditions. The purchase price for the acquisition is US$315 million subject to working capital adjustments and other closing adjustments.

The acquisition is expected to exceed the targeted rate of return Capital Power seeks from merchant assets, and be accretive to earnings both immediately and over the life of the facilities. Depending on the permanent financing alternative selected for the acquisition, Capital Power expects the acquisition to add on average $0.02 to $0.07 in earnings per share per year in the first two years. Earnings from the facilities are expected to increase significantly following the expected recovery of power prices in the New England market as the U.S. economy strengthens.

Both plants are merchant facilities and sell their output into the New England Power Pool (NEPOOL). The plants began commercial operations in 2000 and have similar design configurations that utilize a single fuel GE 7FA power island. The Company commissioned and operates similar technology at the Frederickson power facility in Washington State.

Tiverton and Rumford supply electricity to the New England Independent System Operator (ISO-NE). Both plants are exempt wholesale generators and have Federal Energy Regulatory Commission (FERC) authorization to sell capacity, energy, and ancillary services at market-based rates. The plants are operated as mid-merit generation units and sell their outputs on an hourly basis into the NEPOOL. The NEPOOL serves six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont which contain approximately 14 million people and over 6 million households and businesses. The NEPOOL is subject to FERC jurisdiction and has more than 400 participants, over 8,000 miles of transmission lines, and 13 interconnections to the New York and Canadian power systems. It is one of the most advanced and liquid markets in the U.S. and has a peak demand of approximately 28,000 MW.

**Acquisition of a third New England power plant**

The Company has entered into an agreement to acquire Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport Energy), from affiliates of LS Power Equity Advisors, LLC. Bridgeport Energy is a natural gas-fired combined cycle power generation plant located in Bridgeport, Connecticut, with a nominal capacity of 520 MW. It is an efficient, young, mid-merit generation plant that can maximize energy and ancillary services revenue through operational flexibility.

Under the purchase and sale agreement, CPLP is acquiring one hundred per cent of the equity interests in Bridgeport Energy, LLC. The transaction is expected to close in May 2011, subject to regulatory approvals and satisfaction of other customary closing conditions. The purchase price for the acquisition is US$355 million subject to working capital adjustments and other closing adjustments.

The Company expects to permanently finance both New England acquisitions using a combination of debt and equity. The Company has entered into an agreement to sell 8,100,000 common shares of Capital Power on a bought deal basis at a price of $24.90 per share to a syndicate of underwriters, co-led by TD Securities Inc. and CIBC World Markets Inc., for gross proceeds of $201,690,000. In addition, Capital Power has granted the syndicate an over-allotment option, exercisable for a period of 30 days following closing, to purchase up to an additional 1,215,000 shares which, if exercised, would increase the gross offering size to $231,943,500. The offering is scheduled to close on or about March 17, 2011, and is subject to TSX approval and other customary conditions.

As part of the NEPOOL, Bridgeport Energy dispatches into the premium Southwest Connecticut Zone of the ISO-NE market, and has historically received payments for energy, capacity and ancillary services. Bridgeport Energy is a modern, efficient plant that has among the lowest heat rates in ISO-NE. The site has adequate space to develop a peaking facility when market conditions warrant.

Bridgeport Energy entered commercial operation in July 1999. It is equipped with two Siemens V84.3A gas turbines, which are the same design as those used at CPILP's facility in Colorado, and produces additional output from two Heat Recovery Steam Generators and one single-reheat condensing steam turbine. Electrical interconnection into the United Illuminating system is made via the Singer 345kV substation, and natural gas is supplied through a lateral to the Iroquois Gas pipeline system. The facility was designed to minimize environmental impacts and utilizes advanced emission control technologies, including selective catalytic reduction nitrogen oxide controls.

## Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on March 9, 2011 at 1:00 pm (ET) to discuss fourth quarter and year-end results. The conference call dial-in numbers are:

(403) 532-8075 (Calgary)
(604) 681-0262 (Vancouver)
(647) 837-0597 (Toronto)
(877) 353-9586 (toll-free from Canada and USA)

Participant access code for the call: 21543#

A replay of the conference call will be available following the call at: (877) 353-9587 (toll-free) and entering pass code 536068. The replay will be available until midnight on April 6, 2011.

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

## Non-GAAP Financial Measures

The Company uses (i) gross margin, (ii) operating margin, (iii) funds from operations, (iv) funds from operations excluding non-controlling interests in CPILP (v) normalized net income attributable to common shareholders, and (vi) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to Canadian GAAP and do not have standardized meanings prescribed by Canadian GAAP, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, cash flow from operating activities, earnings per share 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. Reconciliations of gross margin and operating margin to net income, funds from operations and funds from operations excluding non-controlling interests in CPILP to cash provided by operating activities, normalized net income attributable to common shareholders to net income (loss) attributable to common shareholders, and normalized earnings per share to earnings per share are contained in the Company's annual Management's Discussion and Analysis dated March 8, 2011 for the year ended December 31, 2010.

## Forward-looking Information

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

Forward-looking information in this press release includes, among other things, information relating to: (i) expectations regarding the review of strategic alternatives for CPILP, its potential outcome, and the intention of Capital Power to support the review of strategic alternatives but not participate as a prospective buyer if a sale were to occur; (ii) expectations regarding the timing of the CPILP strategic review process and that during the review process CPILP will continue its business as usual, provide the same amount of monthly distributions to its unitholders and maintain the same proposition it offers today; (iii) Capital Power's intention to continue managing CPILP assets; (iv) expected contracted price for power under the OPA's FIT program for Port Dover & Nanticoke Wind project; (v) expectations regarding the impact of Island Generation on earnings and cash flow; (vi) expectations regarding amount and timing of future distributions; (vii) expected timing of commercial operations and expected project costs of the Quality Wind and Port Dover & Nanticoke Wind projects; (viii) expectations that the Tiverton and Rumford acquisition will exceed the targeted rate of return Capital Power seeks from merchant assets and expectations regarding accretion to earnings and impact on earnings per share; (ix) expectations regarding the purchase price, timing of closing and financing of the Tiverton, Rumford and Bridgeport acquisitions; (x) expectations regarding the ability to attain the goal of 10,000 MW of assets by 2020; (xi) expectations regarding the impact on earnings from the Tiverton and Rumford plants as a result of the expectation that power prices will recover in the New

England market; and (xii) expectations that Bridgeport can maximize energy and ancillary services revenue through operational flexibility.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements include, but are not limited to: (i) the operation of the Company's facilities; (ii) power plant availability and dispatch, including Sundance which is subject to an acquired PPA; (iii) the Company's financial position and credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) weather; (vii) availability and cost of labour and management resources; (viii) performance of contractors and suppliers; (ix) availability and cost of financing; (x) foreign exchange rates; (xi) management's analysis of applicable tax legislation; (xii) currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; (xviii) ability to obtain necessary regulatory approvals for development projects; (xix) the Company's assessment of capital markets and ability to complete future share and debt offerings; (xx) locations of projects and the areas of which they will be developed, including the availability and use of certain optioned lands; (xxi) costs of construction and development; and (xxii) current risk management strategies including hedges will be in place.

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

**About Capital Power Corporation**

Capital Power is a growth-oriented North American independent power producer, building on more than a century of innovation and reliable performance. The Company's vision is to be recognized as one of North America's most respected, reliable and competitive power generators. Headquartered in Edmonton, Alberta, Capital Power has interests in 32 facilities in Canada and the U.S. totaling nearly 3,800 megawatts of generation capacity. Capital Power and its subsidiaries develop, acquire and optimize power generation from a wide range of energy sources.

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# CAPITAL POWER CORPORATION

# Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated March 8, 2011, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the year and six months ended December 31, 2010, and December 31, 2009, respectively, the annual information form (AIF) of Capital Power Corporation dated March 8, 2011 and the cautionary statement regarding forward-looking information which begins on page 62. 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 year ended December 31, 2010 and six months ended December 31, 2009 is based on the audited 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 audited financial statements for the year ended December 31, 2010 include prior year comparative information for the six months ended December 31, 2009. To facilitate the analysis of the Company's audited financial statements this MD&A includes unaudited pro forma consolidated financial information for the year ended December 31, 2009. As six months of the twelve-month comparative period predate the closing of the IPO, this comparative financial information is provided for reference purposes only and is not intended to be a comprehensive comparison of financial results.

The Company's outstanding share capital on December 31, 2010 consisted of 30.981 million common shares, 5 million Cumulative Rate Reset Preference Shares, Series 1, 47.416 million special voting shares and one special limited voting share.

## The Business

The Company's power generation operations and assets are owned by Capital Power LP (CPLP), a subsidiary of the Company. At December 31, 2010, the Company indirectly held approximately 21.75 million general partnership units and 9.209 million common limited partnership units of CPLP which represented approximately 27.75% and 11.75%, respectively, of CPLP, and EPCOR held 47.416 million exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power Corporation on a one-for-one basis) representing approximately 60.5% of CPLP. The general partner of CPLP is wholly-owned by Capital Power and EPCOR's representation on the Board of Directors does not represent a controlling vote. Accordingly, Capital Power controls CPLP and the operations of CPLP have been consolidated for financial statement purposes.

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

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

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

These items did not have a material impact on the Company's consolidated revenues, income from continuing operations, or income before income tax expense for the year ended December 31, 2010 and six months ended December 31, 2009 or on the Company's consolidated total assets or total liabilities as at December 31, 2010 and December 31, 2009. CPLP's consolidated revenues, income from continuing operations, income before income tax expense and non-controlling interests for the year and six months ended December 31, 2010 and December 31, 2009, respectively, and consolidated total assets and total liabilities as at December 31, 2010 and December 31, 2009 represent 97% or more of the corresponding consolidated items of the Company.

## Corporate Strategy

Capital Power's corporate strategy seeks to balance a strong financial position with targeted growth. The Company is committed to maintaining a stable dividend, an investment-grade credit rating supported by contracted cash flows, and a prudent expansion strategy.

The key components of Capital Power's corporate strategy are as follows:

**Continued focus on operational excellence and environmental and safety leadership**

Capital Power's operational strategy is to safely manage, operate and maintain its power generation facilities in a manner that maximizes efficiency, productivity and reliability, and minimizes costs while reducing environmental impact. Capital Power is committed to maintaining its facilities' record of strong operational performance by continuing to plan and monitor maintenance requirements in order to ensure high levels of fleet availability. In addition, Capital Power is working with federal and provincial governments to develop technologies that will enhance the feasibility of near-zero emission coal-fired power generation. The Company also remains committed to a culture of zero injury and occupational illness.

**Strong and sustainable growth**

The Company's target for growth is to have 10,000 MW of owned or operated generation capacity by 2020. The Company has a pipeline of projects under construction or development. Building on the success of Genesee 3 and Clover Bar Energy Centre, the Company is building the Keephills 3 facility, representing 495 megawatts (MW) of new generation capacity, of which Capital Power has a 248 MW ownership interest. Keephills 3 is expected to commence commercial operations by the end of the second quarter of 2011. The Company is also developing two new wind projects, Quality Wind in British Columbia and Port Dover & Nanticoke in Ontario, representing 142 MW and 105 MW, respectively. On October 19, 2010, the Company acquired Island Generation, a 275 MW gas-fired combined cycle power plant at Campbell River, British Columbia. These two wind development projects and the Island Generation acquisition are discussed under Significant Events. In the first quarter of 2011, the Company entered into two agreements to acquire three natural gas-fired combined cycle power generating facilities in the New England states with a maximum combined capacity of 1,069 MW, as discussed under Subsequent Events. The Company has a number of other projects in various stages of development and it continues to evaluate acquisition prospects, primarily in the U.S., to strengthen its regional footprint and existing portfolio. As market conditions create new opportunities, the Company expects to capitalize on its experience to seek to acquire high quality assets. For 2011, the Company's target is to commit at least $1.5 billion of new development or acquisitions. However, to help ensure that the Company's financial condition is not compromised by its growth strategy it has set internal rates of return targets for acquisition and development project opportunities. Because of the Company's focus on growth, the Company has chosen to make construction a core competency.

In 2010, CPILP initiated a process to review its strategic alternatives, supported by Capital Power Corporation as described under Significant Events. During this process, it is business as usual and Capital Power Corporation continues to provide ongoing operational and management services to CPILP.

**Networked hub strategy**

The Company's networked hub strategy is to manage power generation assets at the hub level rather than by individual facility in order to be a cost-effective provider of electricity in the Company's markets. The foundation of this strategy is to establish generation hubs by acquiring larger-scale, fossil-fuel based power plants supplemented by renewable facilities, in the Company's markets. In order to reduce purchasing, warehousing, inventory and other costs, the Company seeks to standardize these plants by fuel type and technology. The Company then seeks to enter into non-unit-specific contracts to provide it with flexibility in deploying its generation assets. The availability of physical generation from multiple sources in a market area provides the Company with the flexibility to better meet customer requirements and optimize its portfolio of assets in the networked hub in response to factors such as heat rate and commodity prices. Heat rate is the amount of combustible fuel (e.g. natural gas or coal) required to produce a unit of electricity. The Company believes that its approach of managing assets at the hub level improves efficiency and reduces risk through portfolio diversification.

**Technology preference**

In its selection of future power generation technologies Capital Power plans to capture economies of scale, accommodate emerging market supply and demand trends and further develop distinctive competencies. The Company expects to focus primarily on larger-scale, fossil fuel-fired technologies, supplemented by renewable facilities that are economically attractive and supportive of the Company's long-term contracting position. Fossil fuel-fired facilities will remain a core component of the Company's portfolio and Capital Power remains committed to being a leader in the development of technologies that establish or maintain economic or environmental advantages over other power generators.

**Regional footprint**

Capital Power intends to confine its regional footprint to Canada and the U.S. and seeks to enhance its regional diversification by focusing on a select group of target markets across Canada and the U.S. Capital Power uses a disciplined approach to selecting target regions with a preference for markets with favourable long-term fundamentals and spark spreads, including regulatory frameworks conducive to competitive power generation, sufficient scale to support the establishment of a networked hub of power facilities, and liquid trading markets. Spark spread means the theoretical difference between the price of electricity as the output and its energy cost of production.

Capital Power intends to maintain its existing strong position in Alberta and focus on developing additional hubs in the following three regions: Mid-Atlantic U.S., including the PJM (Pennsylvania, New Jersey and Maryland) Interconnection and the Virginia-Carolinas; the Northeast U.S., including the New York Independent System Operator and the New England Power Pool (NEPOOL); and the Southwest U.S., including the California Independent System Operator and Desert Southwest (Arizona, New Mexico and Nevada). In addition, other North American markets, especially where Capital Power has existing operations, are considered on a case-by-case basis if opportunities arise for the development of contracted facilities. For example, in 2010, Capital Power entered into new long-term contracts for renewable projects in the Ontario and British Columbia markets.

**Financial discipline**

Capital Power is committed to a policy of financial discipline founded upon operational success, long-term contracting and targeted growth while maintaining an investment-grade credit rating. Capital Power believes that by maintaining a strong financial position with an appropriate dividend yield on its common shares, it will remain well positioned to access the capital markets to finance acquisitions or strategic development opportunities. To help achieve these objectives, Capital Power expects to continue to sell forward a significant portion of its generation output and capacity under long-term contracts and maintain a target for contracted plants to provide approximately 50% of the Company's total operating margin.

The Company measures its performance in relation to the corporate strategy through financial and non-financial targets that are approved by the Board of Directors. The measurement categories include corporate measures and core measures. The corporate measures are company-wide and include funds from operations, safety and people. The core measures are specific to certain groups of the Company and include plant operating margin, committed capital, construction budget and schedule, and plant site safety.

## Financial Highlights

| (unaudited, $millions, except earnings per share) | Year ended December 31 2010 | 2009[2] |
|---|---|---|
| Revenues | $ 1,760 | $ 2,158 |
| Gross margin[1] | 768 | 883 |
| Operating margin[1] | 520 | 655 |
| Net income | 137 | 273 |
| Net income attributable to common shareholders | 11 | 51 |
| Earnings per share[3] | $ 0.50 | N/A |
| Fully diluted earnings per share[3][4] | $ 0.50 | N/A |
| Normalized earnings per share[1][3] | $ 1.40 | N/A |
| Funds from operations[1][3] | 354 | N/A |
| Capital expenditures[3] | 337 | N/A |
| Long-term debt including current portion[3] | 1,869 | N/A |
| Total assets[3] | 5,217 | 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 year ended December 31, 2009 are unaudited pro forma consolidated financial information included in the Pro forma Consolidated Financial Information section.

(3) Certain financial highlights are not applicable (N/A) for the year ended December 31, 2009 as the unaudited pro forma financial information does not include a balance sheet, a statement of cash flows or earnings per share.

(4) 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.

## Funds from Operations

| (unaudited, $millions) | Year ended | Three months ended | | | Six months ended | Three months ended | |
|---|---|---|---|---|---|---|---|
| | Dec 31, 2010 | Dec 31, 2010 | Sept 30, 2010 | June 30, 2010 | Mar 31, 2010 | Dec 31, 2009 | Dec 31, 2009 | Sept 30, 2009 |
| Funds from operations excluding non-controlling interests in CPILP[1][2] | $ 263 | $ 62 | $ 90 | $ 36 | $ 75 | $ 124 | $ 52 | $ 72 |
| Funds from operations[1][2] | **354** | **82** | **112** | **58** | **102** | **171** | **75** | **96** |

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

(2) Amounts for previous quarters have been reclassified to conform to the presentation adopted in the fourth quarter of 2010.

Funds from operations are cash provided by operating activities excluding changes in working capital. Funds from operations excluding non-controlling interests in CPILP for the year ended December 31, 2010 were slightly ahead of management's expectations primarily due to higher operating margins, excluding unrealized fair value changes, from the Alberta commercial plants and portfolio optimization in the first quarter.

In the fourth quarter, funds from operations excluding the non-controlling interest in CPILP were reduced by $8 million of maintenance costs for the scheduled outage at Genesee 3, as well as the reduction in revenues due to the plant's outage. This was partly offset by cash flows from Island Generation which was acquired on October 19, 2010, as discussed under Significant Events. In the third quarter of 2010, funds from operations included the recognition of an estimated business interruption insurance recovery of $8 million relating to the Clover Bar Energy Centre Unit 2 outage in March 2010 through to September 2010. In the second quarter of 2010, availability penalties and maintenance costs for a scheduled outage at Genesee 2 reduced funds from operations. In the first quarter of 2010, funds from operations reflected higher than anticipated operating margin, excluding fair value changes, from the Alberta commercial plants and portfolio optimization as low spot power prices resulted in higher realized prices on the trading transactions that settled in the quarter.

Funds from operations include CPILP's funds from operations, which were relatively stable over the six quarters with seasonal fluctuations at the individual facilities. Pricing under the power sales contracts for the Ontario plants is higher in the winter months while demand for power from the California facilities is higher in summer months.

Since the non-controlling interests in CPILP's funds from operations were approximately 70.4% (at December 31, 2010) the Company uses funds from operations excluding non-controlling interests in CPILP to provide a more meaningful measure of the Company's operating cash flows.

## Normalized Net Income Attributable to Common Shareholders and Normalized Earnings per Share

| (unaudited, $millions except earnings (loss) per share and shares outstanding) | Year ended | Three months ended | | | | Six months ended | Three months ended | |
|---|---|---|---|---|---|---|---|---|
| | Dec 31, 2010 | Dec 31, 2010 | Sept 30, 2010 | June 30, 2010 | Mar 31, 2010 | Dec 31, 2009 | Dec 31, 2009 | Sept 30, 2009 |
| Earnings (loss) per share | **$ 0.50** | **$ (0.04)** | **$ 0.32** | **$ (0.37)** | **$ 0.60** | **$ 0.97** | **$ 0.33** | **$ 0.64** |
| Net income (loss) attributable to common shareholders | 11 | (1) | 7 | (8) | 13 | 21 | 7 | 14 |
| Adjustments | 20 | 7 | 5 | 9 | (1) | (8) | (3) | (5) |
| Normalized net income attributable to common shareholders[1] | 31 | 6 | 12 | 1 | 12 | 13 | 4 | 9 |
| Weighted average number of common shares outstanding (millions) | 22.19 | 23.47 | 21.77 | 21.75 | 21.75 | 21.75 | 21.75 | 21.75 |
| Normalized earnings per share[1] | **$ 1.40** | **$ 0.26** | **$ 0.55** | **$ 0.05** | **$ 0.55** | **$ 0.60** | **$ 0.18** | **$ 0.42** |

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

Normalized net income attributable to common shareholders for the year ended December 31, 2010 was slightly ahead of management's expectations primarily due to higher operating margins, excluding unrealized fair value changes, from the Alberta commercial plants and portfolio optimization in the first quarter. Normalized net income for each quarter of 2010 was impacted by the factors described above under Funds from Operations.

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

## Pro forma Consolidated Financial Information

The pro forma consolidated financial information for the year ended December 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 date 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 differed from the pro forma adjustments.

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

| (unaudited, $millions) | Year ended December 31 2010 | 2009[1] |
|---|---|---|
| Revenues | $ 1,760 | $ 2,158 |
| Energy purchases and fuel | 992 | 1,275 |
| | 768 | 883 |
| Operations, maintenance and direct administration | 230 | 209 |
| Indirect administration | 133 | 133 |
| Property taxes | 18 | 19 |
| Depreciation, amortization and asset retirement obligations accretion | 197 | 183 |
| Foreign exchange losses | 1 | 6 |
| Gains on acquisitions and disposals | (30) | (30) |
| Net financing expenses | 74 | 77 |
| | 623 | 597 |
| Income before income tax expense and non-controlling interests | 145 | 286 |
| Income tax expense | 8 | 13 |
| **Net income** | **$ 137** | **$ 273** |
| Net income attributable to: | | |
| Non-controlling interests | | |
| - CPLP | $ 88 | $ 183 |
| - CPILP | 24 | 32 |
| - Preferred share dividends paid by CPI Preferred Equity Ltd.[2] | 14 | 7 |
| | 126 | 222 |
| Common shareholders | **$ 11** | **$ 51** |

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

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

## Consolidated Net Income

| (unaudited, $millions) | |
|---|---|
| **Consolidated net income for the year ended December 31, 2009[1]** | **$ 273** |
| Higher Alberta commercial plants and portfolio optimization operating margin | 15 |
| Higher Ontario and British Columbia contracted plants operating margin | 5 |
| Lower foreign exchange losses | 5 |
| Lower income taxes | 5 |
| Lower Alberta contracted plants operating margin | (9) |
| Unrealized changes in the fair value of CPILP's derivative instruments | (11) |
| Higher depreciation, amortization and asset retirement obligations accretion | (14) |
| Lower other portfolio activities operating margin | (18) |
| Unrealized changes in the fair value of CPLP's energy derivative instruments and natural gas inventory held for trading | (109) |
| Other | (5) |
| Decrease in net income | (136) |
| **Consolidated net income for the year ended December 31, 2010** | **$ 137** |

(1) Net income for the year ended December 31, 2009 is based on pro forma consolidated information.

Net income decreased $136 million for the year ended December 31, 2010, compared with 2009 due to the net impact of the following:

- Alberta commercial plants and portfolio optimization operating margin was higher primarily due to higher margins realized on merchant trading and higher contributions from the Clover Bar Energy Centre. Availability of Clover Bar Energy Centre increased following the addition of Units 2 and 3 on their commercial operation dates of September 1, 2009 and December 16, 2009, respectively.
- Ontario and British Columbia contracted plants operating margin was higher primarily due to contributions from Island Generation following the Company's acquisition of the facility on October 19, 2010.
- Foreign exchange losses were lower as a result of the impact of a smaller weakening of the U.S. dollar relative to the Canadian dollar on the translation of U.S. monetary assets and liabilities in 2010 compared with 2009.
- Income taxes were lower primarily due to lower income before income tax expense, partly offset by the recognition of an $11 million future income tax liability in the third quarter of 2010 relating to the review of strategic alternatives with respect to the Company's investment in CPILP discussed under Significant Events.
- The operating margin for the Alberta contracted plants was lower primarily due to higher availability penalties and maintenance costs for the 21-day scheduled maintenance outage at Genesee 2 in the second quarter of 2010 compared with the 18-day scheduled maintenance outage at Genesee 1 in the fourth quarter of 2009. The higher availability penalties in 2010 also reflected the impact of higher Alberta power prices at the time of the outage.
- The unrealized changes in the fair value of CPILP's derivative instruments that were not designated as hedges for accounting purposes reflected smaller gains on foreign exchange contracts in 2010 compared with 2009. The unrealized gains in both years were due to strengthening future prices for the Canadian dollar relative to the U.S. dollar. The fair value of CPILP's natural gas supply contracts decreased in both years due to decreases in the future prices for natural gas. The unrealized fair value loss recognized in the income statement was smaller in 2010 as CPILP designated certain contracts as hedges for accounting purposes effective July 31, 2009 and the fair value losses relating to those contracts after that date were recorded in other comprehensive income.
- Depreciation expense was higher following the acquisition of Island Generation in the third quarter of 2010. Depreciation on Clover Bar Energy Centre was higher as all three units were operational in the year ended December 31, 2010 whereas only one unit was operational throughout the corresponding period in 2009 and the two other units commenced operations in September and December 2009.
- The operating margin for other portfolio activities decreased primarily due to lower natural gas speculative trading profit and fewer electricity import and export market trading opportunities as a result of lower price spreads and less volatility in prices in 2010 compared with 2009.
- The fair value of CPLP's derivative instruments and natural gas storage held for trading that were not designated as hedges for accounting purposes, decreased $26 million in 2010 primarily due to the reversal of prior years' gains associated with contracts that settled in 2010, partly offset by the impact of increases in Alberta forward power prices on portfolio positions. In 2009, the fair value of these instruments increased $83 million, reflecting the impact of decreases in Alberta forward power prices on portfolio positions.

## 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 certain assumptions and subject to certain risks as of the date of this MD&A and as disclosed in that section. These forward-looking statements are for the purpose of providing information about management's current expectations and plans relating to the future and may not be appropriate for other purposes.

The Company's operating results for the year ended December 31, 2010 were ahead of management's expectations primarily due to higher operating margins, excluding unrealized fair value changes, from the Alberta commercial plants and portfolio optimization. These higher operating margins were partly offset by unanticipated accounting losses associated with the recognition of the Island Generation acquisition as discussed under Significant Events, and with a future income tax provision related to the Company's investment in CPILP. Excluding these accounting losses and unrealized fair value changes, the Company's full year results were ahead of the Company's expectations that were provided in the Outlook Section of the December 31, 2009 MD&A.

The operating margin for Island Generation was $6 million compared with the Company's forecast of $4 million. The difference relates to $2 million of integration and acquisition costs which were included in indirect administration rather than the plant's operating margin as forecasted. Accordingly, Island Generation's operating results were in line with management's expectations.

The Company's plant availability (excluding CPILP plants) for 2010 was 90% compared to a target of 94%. The under performance was primarily due to Clover Bar Energy Centre Unit 2 which was offline from March 8, 2010 to September 22, 2010 due to mechanical issues. The issues were addressed under warranty from the supplier and an estimated insurance recovery for business interruption of $8 million was recorded in the third quarter of 2010, of which $4 million was collected in January 2011. The Company continues to expect to settle the claim and recover the remaining $4 million before the end of the first half of 2011.

The Company has a plant availability target of 94% for 2011. In January 2011, Unit 3 of the Clover Bar Energy Centre experienced an unplanned outage due to blade damage in its high pressure compressor. Capital Power has taken the unit out of service and returned it to the manufacturer for disassembly, analysis and repair. The unit is under warranty, but until the root cause of the damage is determined it is not possible to determine whether the repair costs are covered under warranty. Capital Power has provided the Alberta Electric System Operator (AESO) with an estimated return to service date of June 30, 2011. Capital Power's repair costs, if not covered under warranty, would be subject to a $1 million deductible. Capital Power's business interruption insurance coverage will begin after a 45-day waiting period, and has a $3 million deductible. If the unit is offline for six months of 2011, and Capital Power's other operations perform as expected, the Company will not meet its 2011 plant availability target as the results for this measure would decrease to approximately 91%. Capital Power continues to have 143 MW of peaking capacity available from Clover Bar Energy Centre Units 1 and 2 and the timing of an outage at Unit 2 for an engine upgrade is being planned to coincide with the timing of Unit 3's return to service. This outage of Unit 2 is tentatively scheduled for the summer of 2011.

Normalized earnings per share in 2011, without considering the impacts of International Financial Reporting Standards (IFRS), were originally forecasted to be comparable to the Company's original forecast for 2010 normalized earnings per share of $1.20 per share, at a forecast Alberta power price of approximately $50/MWh in 2011; while funds from operations in 2011 were expected to be modestly higher than 2010 levels. Items impacting the year over year comparison are as follows:

- The Company's original forecast was for average Alberta power prices in 2011 to be moderately lower than they were in 2010, which would lead to lower realized prices on the Company's position that is economically unhedged, lower profitability from peaking facilities, and lower availability incentive revenues from Genesee 1 and 2;
- The Keephills 3 plant is expected to come on-line in the second quarter of 2011 and is expected to generate positive incremental cash flow but be dilutive to earnings per share at the forecast power price levels noted above; and
- At the start of 2010, the forecast generation for 2010 from the base-load plants in the Alberta commercial portfolio was substantially sold forward at an average price of mid-$60/megawatt hour (MWh) compared to the following portfolio positions for 2011, 2012 and 2013 at the start of 2011:

| **Alberta Power Price Sensitivity** | 2011 | 2012 | 2013 |
|---|---|---|---|
| % Sold forward | 73% | 34% | 17% |
| Contracted price | Low-$60/MWh | Mid-$60/MWh | Mid-$60/MWh |

At the beginning of 2011, the Company expected 2010 and 2011 Alberta power prices to be at the bottom of the power price cycle followed by a recovery in 2012.

These potential reductions to normalized earnings per share are expected to be mostly offset by improved earnings from:

- A full year of operations from the Island Generation facility acquired in October 2010 as discussed under Significant Events. Island Generation is expected to contribute $24 million to $28 million in operating margin in 2011; and
- One scheduled maintenance outage at Genesee 1 in the spring of 2011 compared to two scheduled outages in 2010, one at Genesee 2 and one at Genesee 3. The outage at Genesee 1 is expected to last 21 days and cost approximately $13 million in maintenance expenses.

The Company's normalized earnings per share in 2011 could also benefit from increased Alberta power prices stemming from TransAlta Utilities Inc's (TransAlta) recent announcement surrounding Sundance 1 and 2. Both base load coal-fired power plants went offline in mid December 2010 and due to the magnitude of damage on both assets, TransAlta intends to terminate the Power Purchase Arrangements (PPAs) for these units, thereby removing 560 MW from the Alberta power grid. From the end of the third quarter of 2010 to the middle of February 2011, average 2011 forward prices for Alberta power, inclusive of January and February 2011 actual spot prices, rose $20/MWh to $65/MWh. However, it is likely that the counterparty to the PPA and/or the Alberta Balancing Pool will dispute TransAlta's determination. Accordingly, the outcome of this event is uncertain. Based on the Company's Alberta portfolio position in January and February, 2011 when power prices spiked up, the Company expects its earnings and funds from operations in the first quarter of 2011 to be well below the financial performance of the first quarter of 2010 as well as the Company's planned performance for the first quarter of 2011. If prices for the balance of 2011 settle at the forward rates of early March 2011, the Company expects full year earnings and funds from operations to exceed previous guidance and internal plans.

Other 2011 Company performance targets which have not yet been updated for the impacts of IFRS, are as follows:

| **Performance Measures** | **2011 Targets** |
|---|---|
| Allocated Capital | |
| Committed capital for acquisitions/developments that are in-line with targeted rates of return | $1.5 billion or higher |
| Operational | |
| Plant availability average | 94% or greater |
| Plant maintenance capital expenditures and Genesee mine extension | Approximately $40 million |
| Construction / Development | |
| Capital Power's final costs in the construction of Keephills 3 plant | $955 million or less with commercial operation date in the second quarter of 2011 |
| Quality Wind and Port Dover & Nanticoke wind projects | Continue on time and on budget with commercial operation dates in 2012 |
| Investment Performance | |
| Total shareholder return | Deliver total shareholder return that exceeds the median of the Company's peer group |

The 2011 targets and normalized earnings per share forecasts are based on numerous assumptions including power and natural gas price forecasts, as described in the Forward-looking Information Section. However, they do not include assumptions regarding changes to the current ownership or business of CPILP resulting from the strategic alternatives review, potential impacts from future acquisitions or development activities (including the acquisitions described under Subsequent Events), or potential impacts from unplanned plant outages including outages at facilities of other market participants and the related impacts on market power prices.

CPILP's process to review strategic alternatives is anticipated to take place over the next several months. During this period it is anticipated that CPILP will continue to provide the same amount of monthly distributions to its unitholders and maintain the same strategy supported by its high quality portfolio of contracted power assets, and Capital Power Corporation will continue to manage CPILP's assets.

CPILP's assets and contracts are expected to provide long-term stable cash flows. While CPILP is now subject to Canadian SIFT taxes, it does not expect to make any material cash income tax payments until 2015 or 2016 in both Canada and the U.S., primarily due to tax losses and undepreciated capital cost pools available to the partnership to deduct against future taxable income.

CPILP expects its cash provided by operating activities before working capital changes in 2011 will be higher than in 2010 based on expectations for higher dispatch of the North Carolina plants, renewal of the PPAs for the North Carolina facilities and higher contracted prices on foreign exchange contracts that will settle in 2011 versus 2010.

CPILP expects that current distributions of $1.76 per unit per year can be maintained until the end of 2014, based on its current strategy which may change depending on the outcome of the review of its strategic alternatives. The ability of CPILP to sustain its current level of cash flows to 2014 and beyond is subject to a number of risks and uncertainties including:

- the ability to secure new contracts, and the terms of such contracts, to replace existing contracts as they expire, particularly at the Ontario facilities with their uncertain outlook for waste heat availability and electricity demand;
- the terms of new PPAs for the North Carolina facilities;
- the ability to find and successfully execute cash accretive investments;
- the ability to secure wood waste on a cost effective basis, particularly in Ontario; and
- the repayment terms of new financing agreements to be arranged as the current agreements expire.

The PPAs for the North Carolina facilities expired on December 31, 2009. CPILP initiated an arbitration process with the North Carolina Utilities Commission (NCUC) seeking long-term PPAs with pricing terms consistent with Progress' actual avoided costs. The NCUC issued a decision in January 2011 setting out guidelines for the new PPAs. While the NCUC ruling supported the majority of the partnership's positions, it did not completely align with the partnership's economic projections. Accretion for the North Carolina plant enhancement project is expected to be significantly lower than the $0.10 per partnership unit previously anticipated by CPILP.

In the fourth quarter of 2010, CPILP completed the final phase of the North Carolina plant enhancement project which was designed to reduce environmental emissions and improve economic performance by increasing the use of tire-derived fuel and wood waste in the fuel mix. The partnership had anticipated a reduction in the capacity of Southport and Roxboro to approximately 88 MW and 46 MW, respectively. However, recent testing indicated that the plants may only be able to achieve capacities of 84 MW - 87 MW at Southport and 42 MW - 44 MW at Roxboro based on the targeted fuel mix. CPILP management is assessing whether a shortfall in capacity can be practically resolved.

The Company's estimated capital expenditures in 2011 in the following table exclude potential acquisitions or new development projects, and the acquisitions announced in the first quarter of 2011 (see Subsequent Events).

| (unaudited, $millions) | | | Year ended December 31, | |
|---|---|---|---|---|
| **Capital Expenditures** | | | 2011 Estimated[1] | 2010 Actual |
| CPLP | Sustaining | Plant maintenance | 25 | 15 |
| | | Genesee mine | 12 | 11 |
| | | Information technology | 13 | 5 |
| | | Other | 20 | 25 |
| | | | 70 | 56 |
| CPLP | Growth | Keephills 3 | 63 | 217 |
| | | Quality Wind | 148 | 23 |
| | | Port Dover & Nanticoke | 98 | 21 |
| | | | 309 | 261 |
| CPLP Total | | | 379 | 317 |
| CPILP | Sustaining | Plant maintenance | 25 | 8 |
| | Growth | | 5 | 12 |
| CPILP Total | | | 30 | 20 |
| | | | 409 | 337 |

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

Construction of Keephills 3 remains on schedule for commercial operation by the end of the second quarter of 2011. The Quality Wind and Port Dover & Nanticoke projects as discussed under Significant Events are expected to be in operation by the end of 2012 with total project costs estimated at $795 million. The 2011 estimated capital expenditures for information technology are primarily for a new energy trading and risk management system. Included in the other capital expenditure estimate in the above table are leasehold improvements for the Company's Edmonton and Calgary offices as their leases expire in 2011. The estimated 2011 capital expenditures are higher for Keephills 3 and lower for Quality Wind than previously disclosed, resulting in a net increase of $9 million for the total for growth projects. The increase is primarily due to expenditures on Keephills 3 that were deferred from 2010 to 2011 as discussed under Liquidity and Capital Resources. However, no change in the estimated total cost of each project is anticipated. CPILP's capital expenditures in 2011 are anticipated to include $5 million for final system testing and access road construction at its Southport facility.

The Company will continue to seek to develop its business through acquisitions or construction projects with a target of $1.5 billion of capital to be committed in 2011.

Capital Power's proposed 270 MW Kingsbridge II project is located in an Ontario region that is subject to transmission constraints. In 2010, the Ontario Power Authority (OPA) deemed that upgrades to the Bruce-Milton transmission line would add 1,200 MW of capacity for renewable projects in the region. Rights to up to 500 MW of that capacity were allocated to the Samsung Group. Developers proposing projects under the OPA's Feed-in-Tariff (FIT) program will become eligible for interconnection based on an Economic Connection Test (ECT). In December 2010, the OPA released its ranking of launch window projects (projects for which applications were received in the period from October 1, 2009 to November 30, 2009) awaiting the ECT. In February 2011, the OPA released an update to the ranking to include post-launch projects (projects for which applications were received between December 1, 2009 and June 4, 2010). The ranking, based on the developers' proposed timing for commercial operation of their project, confirmed that 2,590 MW of renewable FIT projects (of which 2,453 MW relate to wind projects) were submitted in the Bruce-Huron region. Kingsbridge II ranked 27th out of 55 projects. Inclusive of Kingsbridge II, the top 27 projects would require 1,304 MW of transmission capacity.

The OPA's ECT process will include an assessment as to whether a project will require additional network upgrade facilities or not. Projects determined to require additional network upgrades that would result in costs to rate payers will not be offered a FIT contract. Kingsbridge II would not require network upgrades, which could potentially improve its ranking and lead to the project being offered a FIT contract upon conclusion of the OPA's ECT, which is expected to be completed in the second quarter of 2011. Capital Power also expects that the OPA will not award FIT contracts for the Bruce-Huron area until the Bruce-Milton transmission line receives all necessary approvals in non-appealable form. Although the line is currently under construction, a portion of the route still requires approval from the Niagara Escarpment Commission.

In 2010, BC Hydro announced a competitive call for larger-scale biomass projects, with a target of acquiring up to 1,000 GWh per year of electricity production. Ten proponents bid projects into the call, representing more than 400 MW of capacity and over 3,300 GWh per year of energy at fixed pricing. Capital Power submitted a bid for its 50 MW – 70 MW Houston biomass project. In January 2011, BC Hydro announced a list of preferred proponents to proceed to the next stage of the call. The Houston biomass project was not chosen to proceed to the next phase of the request for proposals at this time.

In 2010, Capital Power formed a joint venture with Greengate Power Corporation (Greengate) to develop the Halkirk I Wind project which is a proposed 150 MW wind farm in central Alberta. Progress on the project is pending Greengate completing its financing, and if it proceeds each firm will own 50% of the project. Greengate will lead the development and Capital Power will manage the construction and operation. Subject to final approval of the project, construction could be completed in 2012.

## Significant Events

**$221 million secondary offering of Capital Power common shares by EPCOR**

In December 2010, a subsidiary of EPCOR exchanged 9,209,000 of its exchangeable limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9,209,000 common shares of Capital Power to the public pursuant to a secondary offering at $24.00 per common share. Capital Power did not receive any of the approximate $221 million of proceeds from EPCOR's sale of common shares. This transaction reduced EPCOR's ownership interest in CPLP to approximately 60.5% from its initial interest of 72.2% and reduced EPCOR's indirect ownership of the common shares of Capital Power on a fully diluted basis to 60.5% from 72.2%. In accordance with the terms of the CPLP partnership agreement, net income from CPLP for the year ended December 31, 2010 was attributed between the partners (subsidiaries of EPCOR and Capital Power) on the same basis as distributions were paid or payable to the partners for the year, which was 69.31% to the EPCOR subsidiary and 30.69% to the Capital Power subsidiary. EPCOR has advised the Company that it intends to eventually sell all or a substantial number of its common shares underlying its exchangeable partnership units of CPLP, subject to market conditions and its requirement for capital in the future.

The common shares were offered in all provinces of Canada by way of a prospectus supplement to a base shelf prospectus of Capital Power. The offering was also extended to qualified institutional buyers in the U.S. pursuant to the exemptions from registration provided by Rule 144A of the Securities Act of 1933, as amended, and internationally where permitted.

**$125 million offering of 4.60% Cumulative Rate Reset Preferred Shares**

On December 16, 2010, Capital Power Corporation issued 5 million Cumulative Rate Reset Preference Shares, Series 1 (Series 1 Shares) at $25 per share for aggregate gross proceeds of $125 million less issue costs of $4 million. The net proceeds were lent to CPLP pursuant to a subordinated debt agreement. CPLP used the funds to repay a portion of the balance outstanding under its credit facilities which was used to fund the acquisition of Island Generation and for general corporate purposes.

The Series 1 Shares will pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last day of March, June, September and December of each year, as and when declared by the Board of Directors of Capital Power, for the initial five-year period ending December 31, 2015. The first quarterly dividend of $0.3308 per share is expected to be paid on March 31, 2011. The dividend rate will be reset on December 31, 2015 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%. The Series 1 Shares are redeemable by Capital Power, at its option, on December 31, 2015 and on December 31 of every fifth year thereafter.

Holders of Series 1 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 2 (Series 2 Shares), subject to certain conditions, on December 31, 2015 and on December 31 of every fifth year thereafter. Holders of Series 2 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.17%, as and when declared by the Board of Directors of Capital Power.

Standard & Poor's, a division of the McGraw Hill Companies, Inc. (S&P) has assigned a rating of P-3 (High) for the Series 1 Shares and DBRS Limited (DBRS) has assigned a rating of Pfd-3 (low) for the Series 1 Shares.

**$300 million debt offering**

On November 16, 2010, CPLP completed a public offering in Canada of unsecured medium term note debentures with a principal amount of $300 million. The notes have a coupon rate of 5.276% and mature on November 16, 2020. The net proceeds of the offering were used to finance a portion of the purchase price for Island Generation, repay amounts owing under the Company's credit facilities and for general corporate purposes.

The notes have been rated BBB by S&P and BBB by DBRS.

**Acquisition of Island Generation facility**

CPLP's acquisition of Island Generation from Kelson Canada Inc. closed on October 19, 2010. Island Generation is a 275 MW gas-fired combined cycle power plant at Campbell River, British Columbia. The Company initially financed the purchase price of $205 million with funds drawn on credit facilities.

Island Generation is fully contracted to April 2022 under an electricity purchase arrangement where BC Hydro is responsible for the fuel supply to the facility. Commissioned in 2002, Island Generation is consistent with Capital Power's fleet of young assets that deploy efficient technologies. Based on the terms of the energy purchase arrangement, the Island Generation facility is expected to be modestly and immediately accretive to earnings, and more significantly accretive to cash flow.

The fair value of the net assets acquired was $207 million or $2 million higher than the purchase price. This excess or bargain purchase gain was recorded in gains on acquisitions and disposals on the income statement in accordance with Section 1582 - Business Combinations of the Canadian Institute of Chartered Accountants (CICA) Handbook. See Business Combinations under Critical Accounting Estimates and Policies. The non-controlling interest's share of the bargain purchase gain was $8 million resulting in a $6 million net loss attributable to the common shareholders.

Capital Power, as a partner of CPLP, is taxable on its share of income from CPLP. Accordingly, a future income tax liability related to Capital Power's interest in the acquisition was included in the net assets acquired. Since CPLP is not taxable, the non-controlling interest's share of the bargain purchase gain was determined before taking into consideration this future income tax liability, and amounted to $8 million. The remaining $6 million loss was attributable to the common shareholders. This outcome is a function of the application of the accounting requirements for business combinations and does not align with the respective partners' economic interests in the transaction. If CPLP was taxable, rather than CPC being taxable on its income from CPLP, the accounting would have resulted in a goodwill asset on the balance sheet and no bargain purchase gains and losses included on the income statement, which is more reflective of the economics of the transaction.

**Review of strategic alternatives for CPILP**

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

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

The process to review strategic alternatives is expected to continue into the second quarter of 2011. During this period it is business as usual for CPILP and Capital Power Corporation and it is anticipated that CPILP will continue to provide the same amount of monthly distributions to its unitholders, and maintain the same investor proposition that it offers today. Capital Power Corporation, through wholly owned subsidiaries, will continue to manage CPILP assets.

**New wind projects**

On March 11, 2010, the Company's Quality Wind project was selected by BC Hydro for the award of an Energy Purchase Agreement, which was signed by the two parties in April 2010. The project is for the development of a 142 MW wind farm near Tumbler Ridge, British Columbia and is expected to cost approximately $455 million. The environmental assessment certificate for the project was received from the Government of British Columbia in July 2010 and construction of the project commenced in the fourth quarter of 2010. The Company anticipates that the plant will commence commercial operation by the end of the fourth quarter of 2012, ahead of the deadline (second quarter of 2013) for power from the plant to be on the grid as required by the Energy Purchase Agreement.

On April 8, 2010, the OPA selected the Company's Port Dover & Nanticoke Wind development project for the award of a contract through the OPA's FIT program. The 105 MW project will be located 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. The contract to sell power has since been signed and under the terms of the OPA's FIT 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% of the contract price will escalate annually at inflation throughout the 20-year contract term. Construction of the Port Dover & Nanticoke Wind project is subject to regulatory approvals, including Ontario's Renewable Energy Approval process which is currently in progress for the project.

The Company selected Vestas (NASDAQ OMX Copenhagen:VWS) for the supply and maintenance of wind turbines for both projects, as well as for the Kingsbridge II project in Ontario.

**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 gain of $28 million. This sale was pursuant to the agreement entered into in June 2006 whereby the Company agreed to sell its Battle River Power 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 gain for the sale of the 15% interest in January 2010 was $28 million compared with $30 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 attributable to common shareholders before giving consideration to the reduction in non-controlling interests discussed under Significant Events - $221 Million Secondary Offering of Capital Power Common Shares by EPCOR. The reduction in non-controlling interests had an immaterial impact on the net income attributed to the common shareholders for this transaction.

## Subsequent Events

**Acquisition of two New England power plants**

In February 2011, CPLP entered into an agreement to acquire two generating facilities from Brick Power Holdings LLC, one facility located in Tiverton, Rhode Island (Tiverton) and one facility located in Rumford, Maine (Rumford). Both plants are natural gas-fired combined cycle power generation facilities serving the New England region in the U.S. Northeast, and have a maximum combined capacity of 549 MW.

The transaction is expected to close in April 2011, subject to regulatory approvals and satisfaction of other customary closing conditions. The purchase price for the acquisition is US$315 million subject to working capital adjustments and other closing adjustments.

The acquisition is expected to exceed the targeted rate of return Capital Power seeks from merchant assets, and be accretive to earnings both immediately and over the life of the facilities. Depending on the permanent financing alternative selected for the acquisition, Capital Power expects the acquisition to add on average $0.02 to $0.07 in earnings per share per year in the first two years. Earnings from the facilities are expected to increase significantly following the expected recovery of power prices in the New England market as the U.S. economy strengthens.

Both plants are merchant facilities and sell their output into the NEPOOL. The plants began commercial operations in 2000 and have similar design configurations that utilize a single fuel GE 7FA power island. The Company commissioned and operates similar technology at the Frederickson power facility in Washington State.

Tiverton and Rumford supply electricity to the New England Independent System Operator (ISO-NE). Both plants are exempt wholesale generators and have Federal Energy Regulatory Commission (FERC) authorization to sell capacity, energy, and ancillary services at market-based rates. The plants are operated as mid-merit generation units and sell their outputs on an hourly basis into the NEPOOL. The NEPOOL serves six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont which contain approximately 14 million people and over 6 million households and businesses. The NEPOOL is subject to FERC jurisdiction and has more than 400 participants, over 8,000 miles of transmission lines, and 13 interconnections to the New York and Canadian power systems. It is one of the most advanced and liquid markets in the U.S. and has a peak demand of approximately 28,000 MW.

**Acquisition of a third New England power plant**

The Company has entered into an agreement to acquire Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport Energy), from affiliates of LS Power Equity Advisors, LLC. Bridgeport Energy is a natural gas-fired combined cycle power generation plant located in Bridgeport, Connecticut, with a nominal capacity of 520 MW. It is an efficient, young, mid-merit generation plant that can maximize energy and ancillary services revenue through operational flexibility.

Under the purchase and sale agreement, CPLP is acquiring one hundred per cent of the equity interests in Bridgeport Energy, LLC. The transaction is expected to close in May 2011, subject to regulatory approvals and satisfaction of other customary closing conditions. The purchase price for the acquisition is US$355 million subject to working capital adjustments and other closing adjustments.

The Company expects to permanently finance both New England acquisitions using a combination of debt and equity. The Company has entered into an agreement to sell 8,100,000 common shares of Capital Power on a bought deal basis at a price of $24.90 per share to a syndicate of underwriters, co-led by TD Securities Inc. and CIBC World Markets Inc., for gross proceeds of $201,690,000. In addition, Capital Power has granted the syndicate an over-allotment option, exercisable for a period of 30 days following closing, to purchase up to an additional 1,215,000 shares which, if exercised, would increase the gross offering size to $231,943,500. The offering is scheduled to close on or about March 17, 2011, and is subject to TSX approval and other customary conditions.

Following both acquisitions, Capital Power will have added or placed into development approximately 2,000 MW of generating capacity since the Company's July 2009 IPO. The acquisitions demonstrate the Company's commitment to its growth strategy aimed at reaching 10,000 MW of assets by 2020. The acquisitions also provide Capital Power with the foundation for a networked hub of assets in the U.S. Northeast, which is one of the Company's target markets, and contributes to a balanced portfolio of contracted and merchant assets. As relatively young, highly efficient gas-fired plants that use proven technologies, these additions to the fleet fit the Company's technology and operating focus. Upon closing of the acquisitions, Capital Power will provide additional guidance, including projections of earnings before interest, taxes, depreciation and amortization.

As part of the NEPOOL, Bridgeport Energy dispatches into the premium Southwest Connecticut Zone of the ISO-NE market, and has historically received payments for energy, capacity and ancillary services. Bridgeport Energy is a modern, efficient plant that has among the lowest heat rates in ISO-NE. The site has adequate space to develop a peaking facility when market conditions warrant.

Bridgeport Energy entered commercial operation in July 1999. It is equipped with two Siemens V84.3A gas turbines, which are the same design as those used at CPILP's facility in Colorado, and produces additional output from two Heat Recovery Steam Generators and one single-reheat condensing steam turbine. Electrical interconnection into the United Illuminating system is made via the Singer 345kV substation, and natural gas is supplied through a lateral to the Iroquois Gas pipeline system. The facility was designed to minimize environmental impacts and utilizes advanced emission control technologies, including selective catalytic reduction nitrogen oxide controls.

## Corporate Update

### Corporate Responsibility Report

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

## Results by Plant Category

The Company reports results of operations in the following categories: (i) Alberta commercial plants and portfolio optimization, (ii) Alberta contracted plants, (iii) Ontario and British Columbia contracted plants, (iv) CPILP plants, and (v) other portfolio activities.

### Alberta commercial plants and portfolio optimization

Alberta commercial plants and portfolio optimization consist of generation facilities for which the Company has not contracted substantially all of their power and capacity to third parties. This category is a networked hub and includes the Company's directly-owned facilities located in Alberta consisting of Genesee 3, Joffre, Clover Bar Energy Centre, Taylor Coulee Chute, Clover Bar Landfill Gas Plant and Weather Dancer, and the Company's interest in the Sundance Power Purchase Arrangement (acquired PPA). The output of the plants, with the exception of Joffre, is sold by the Company into the open Alberta power market. Portfolio optimization includes (i) trading activities in the Alberta market undertaken primarily to manage the Company's exposure to electricity price movements, (ii) power sales contracts with competitive wholesale commercial and industrial customers, and (iii) power supply management for rate-regulated tariff (RRT) customers of regulated retailers.

The Company seeks to maximize earnings from Alberta commercial plants and portfolio optimization by achieving high production from the facilities when it is economic to do so. It also actively manages the commodity price risk of its portfolio of assets and contracts by trading in a variety of financial and non-financial derivative instruments in the Alberta market with power generators, large energy-consuming entities and other trading counterparties. Credit limits are established and monitored by the Company for these counterparties.

**Alberta contracted plants**

Alberta contracted plants are comprised of the Genesee 1 and 2 generation facilities and their capacity and output are sold under a long-term PPA with the Alberta Balancing Pool which expires in 2020. Under the PPA, the Alberta Balancing Pool has the right to dispatch the output from the generation facilities and it pays capacity payments, consisting of fixed operating and maintenance charges, and pays incentive or receives penalty payments based on targeted availability. The Company seeks to maximize earnings for contracted plants by achieving high availability of the plants and managing costs within the PPA terms.

**Ontario and British Columbia contracted plants**

Ontario and British Columbia contracted plants include the Kingsbridge I and Port Albert wind farms in Ontario, the Brown Lake and Miller Creek hydro facilities in British Columbia and the natural gas–fired combined cycle Island Generation plant in British Columbia. Revenues from these plants are earned under contracts with the OPA and BC Hydro and consist of sales of committed capacity or amounts of energy (firm energy sales) and sales of energy generated in excess of the firm commitment amount (excess energy sales).

**CPILP plants**

CPILP plants consist of a fleet of 20 facilities located in Canada and the U.S. with PPAs and fuel supply contracts that provide for stable cash flows. As at December 31, 2010, the Company indirectly owned 29.6% of the limited partnership units of CPILP and it consolidates CPILP's results in its financial statements. In this MD&A the CPILP facilities are discussed on a combined basis rather than individually unless otherwise stated. Eighteen of CPILP's plants are contracted and although the PPAs for the other two plants expired in December 2009, the plants are operating under the terms of the expired PPAs. The status of the negotiations to establish new PPAs for these two plants is discussed in the Outlook section.

**Other portfolio activities**

Other portfolio activities include natural gas trading in North American markets and electricity trading in the eastern Canada, U.S. Northeast and U.S. Pacific Northwest markets. The Company also holds retail and commercial natural gas customer contracts in Alberta but the Company is seeking opportunities to exit these natural gas contracts or allow them to expire as it no longer participates in the competitive natural gas retail market.

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

The Company's financial results for the Alberta commercial and CPILP plants and other portfolio activities include unrealized changes in the fair value of derivative instruments and natural gas inventory held for trading. The Company believes that these unrealized fair value changes are not representative of the instruments' or inventory's underlying economic value when they are not considered in conjunction with the economically hedged items to which they relate, such as natural gas required for future plant operations, future power sales, and future cash flows denominated in foreign currencies. While the changes in the fair value of the derivatives used to hedge the exposures, but not designated as hedges for accounting purposes, are recognized in net income in each reporting period, the changes in the fair value of the associated economically hedged exposures are not. Accordingly, derivative instruments that are recorded at fair value for accounting purposes can produce volatility in net income as a result of changes in forward commodity prices and foreign exchange rates, which does not necessarily represent the underlying economics of the hedging transactions.

While the Company's net income can vary significantly from period to period due to fair value changes that the Company believes are not necessarily representative of the underlying economic performance of the business, the Company's cash flows are relatively stable. Accordingly, management views funds from operations as a key performance indicator since it highlights the key sources of cash generation and liquidity of the Company. See Non-GAAP Financial Measures.

**Generation volume**

| (unaudited, GWh) | Year ended December 31 | |
|---|---|---|
| **Electricity generation**[(1)] | 2010 | 2009 |
| Alberta commercial plants | | |
| Genesee 3 | 1,662 | 1,903 |
| Joffre | 283 | 325 |
| Clover Bar Energy Centre 1, 2 and 3[(2)] | 361 | 34 |
| Taylor Coulee Chute | 11 | 21 |
| Clover Bar Landfill Gas | 38 | 37 |
| Weather Dancer | - | 1 |
| | 2,355 | 2,321 |
| Alberta contracted plants | | |
| Genesee 1 | 3,288 | 3,064 |
| Genesee 2 | 3,046 | 3,260 |
| | 6,334 | 6,324 |
| Ontario and British Columbia contracted plants | | |
| Kingsbridge 1 | 105 | 103 |
| Miller Creek | 95 | 93 |
| Brown Lake | 43 | 53 |
| Island Generation | 273 | - |
| | 516 | 249 |
| **Total excluding CPILP plants** | **9,205** | **8,894** |
| CPILP plants[(3)] | 5,013 | 4,963 |
| **Total plants** | **14,218** | **13,857** |
| | | |
| **Sundance PPA** | **2,908** | **2,361** |

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

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

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

**Plant availability**

| (unaudited) | Year ended December 31 | |
|---|---|---|
| **Generation plant availability**[1] | 2010 | 2009 |
| Alberta commercial plants | | |
| Genesee 3 | 88% | 98% |
| Joffre | 95% | 92% |
| Clover Bar Energy Centre 1, 2 and 3[2] | 71% | 98% |
| Taylor Coulee Chute | 97% | 100% |
| Clover Bar Landfill Gas | 93% | 91% |
| Weather Dancer | 20% | 48% |
| | 84% | 96% |
| Alberta contracted plants | | |
| Genesee 1 | 100% | 93% |
| Genesee 2 | 92% | 98% |
| | 96% | 95% |
| Ontario and British Columbia contracted plants | | |
| Kingsbridge 1 | 99% | 99% |
| Miller Creek | 60% | 89% |
| Brown Lake | 97% | 97% |
| Island Generation | 99% | - |
| | 90% | 95% |
| **Average excluding CPILP plants**[3] | **90%** | **96%** |
| CPILP plants[4] | 95% | 92% |
| **Average all plants**[3] | **92%** | **94%** |
| | | |
| **Sundance PPA** | **93%** | **83%** |

(1) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

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

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

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

The increase in total plant electricity generation excluding the Sundance PPA, for the year ended December 31, 2010 compared with the corresponding period in 2009 primarily relates to Clover Bar Energy Centre, and the addition of Island Generation on October 19, 2010.

Clover Bar Energy Centre generation was higher as it included all three units for the year ended December 31, 2010 whereas only Unit 1 was operational throughout the corresponding period in 2009. Units 2 and 3 commenced operations on September 1, 2009 and December 16, 2009, respectively. The plant's generation for 2010 occurred primarily in the second and fourth quarters during periods of higher Alberta power prices and higher price volatility. Since Clover Bar Energy Centre is a peaking plant, it is dispatched when it is economical to do so which generally is in periods of high power prices. Unit 2 went offline on March 8, 2010 due to a mechanical failure in the main turbine section. The unit came back online on September 22, 2010.

The decrease in generation from the Genesee units in 2010 compared with 2009 primarily relates to a scheduled maintenance outage at Genesee 3 for 42 days in the fourth quarter and at Genesee 2 for 21 days in the second quarter of 2010 compared with an 18-day scheduled outage at Genesee 1 in the fourth quarter of 2009. In addition, all three Genesee units were impacted by curtailments to facilitate transmission upgrades in the second quarter of 2010.

Miller Creek Units 1 and 2 were offline for 144 days in 2010 for scheduled maintenance, compared with 45 days in 2009. As the outages were scheduled during the winter months when the units were not expected to operate as a result of low water flows, the reduced availability did not impact the plant's output relative to expectations.

Sundance Unit 5 was offline for 89 days in the second half of 2009 for a scheduled maintenance outage. There were no similar outages in 2010.

**Financial results**

| (unaudited, $millions) | Year ended December 31 | |
|---|---|---|
| | 2010 | 2009[2] |
| **Revenues** | | |
| Alberta commercial plants and portfolio optimization | $ 918 | $ 1,053 |
| Alberta contracted plants | 272 | 273 |
| Ontario and British Columbia contracted plants | 23 | 16 |
| CPILP plants | 524 | 533 |
| Other portfolio activities | 111 | 150 |
| Inter-plant category transaction eliminations | (41) | (41) |
| | 1,807 | 1,984 |
| Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading | (55) | 115 |
| Unrealized changes in fair value of CPILP's foreign exchange contracts | 8 | 59 |
| | (47) | 174 |
| | **$ 1,760** | **$ 2,158** |
| **Gross margin**[1] | | |
| Alberta commercial plants and portfolio optimization | $ 255 | $ 223 |
| Alberta contracted plants | 216 | 226 |
| Ontario and British Columbia contracted plants | 23 | 16 |
| CPILP plants | 305 | 311 |
| Other portfolio activities | 36 | 55 |
| Inter-plant category transaction eliminations | (37) | (38) |
| | 798 | 793 |
| Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading | (26) | 83 |
| Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts | (4) | 7 |
| | (30) | 90 |
| | **$ 768** | **$ 883** |
| **Operating margin**[1] | | |
| Alberta commercial plants and portfolio optimization | $ 196 | $ 181 |
| Alberta contracted plants | 156 | 165 |
| Ontario and British Columbia contracted plants | 16 | 11 |
| CPILP plants | 183 | 188 |
| Other portfolio activities | 3 | 21 |
| Inter-plant category transaction eliminations | (4) | (1) |
| | 550 | 565 |
| Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading | (26) | 83 |
| Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts | (4) | 7 |
| | (30) | 90 |
| | **$ 520** | **$ 655** |

(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 year ended December 31, 2009 conforms to the presentation for the year ended December 31, 2010. See Pro forma Consolidated Financial Information.

| Spot price averages | Year ended December 31 2010 | 2009 |
|---|---|---|
| Alberta power ($/MWh) | 50.88 | 47.81 |
| Eastern region power ($/MWh) | 36.23 | 29.52 |
| Western region power (Mid-C) ($/MWh) | 33.84 | 36.32 |
| Alberta natural gas (AECO) ($/Gj)(1) | 3.79 | 3.76 |

| | | |
|---|---|---|
| **Capital Power's Alberta portfolio's realized power price** ($/MWh)(2) | 66 | 60 |

(1) Gigajoule (Gj). AECO means a historical virtual trading hub located in Alberta and known as the Nova Inventory Transfer System operated by TransCanada Pipelines Limited.

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

### Alberta commercial plants and portfolio optimization

The gross margin and operating margin for the Alberta commercial plants and portfolio optimization were higher in 2010 compared with 2009 primarily due to higher margins realized on the merchant trading portfolio as well as contributions from the new Clover Bar Energy Centre units. The average Alberta power spot price was $50.88/MWh for 2010 and $47.81/MWh for 2009. The overall portfolio was positioned with less length in 2010 compared with 2009 and this strategy resulted in comparatively higher realized margins. The Company's average realized price for the Alberta commercial portfolio increased from approximately $60/MWh in 2009 to approximately $66/MWh in 2010 as a more significant portion of the Company's Alberta portfolio was sold forward under merchant and wholesale financial contracts at higher prices.

The commodity portfolio optimization strategies were successful in the first and third quarters of 2010 when Alberta power prices averaged $41/MWh and $36/MWh respectively. However, the commodity portfolio optimization strategies had an unfavourable impact in the second quarter of 2010 when Alberta power prices increased to an average of $81/MWh. In the fourth quarter of 2010, Alberta power prices averaged $46/MWh and the commodity portfolio optimization strategies had a slightly favourable impact on results.

In 2010, the portfolio benefited from having more of the Clover Bar Energy Centre available as Units 2 and 3 commenced operations on September 1, 2009 and December 16, 2009, respectively. Higher Alberta spot prices and higher volatility in those prices in the second and fourth quarters of 2010 provided opportunities to dispatch the Clover Bar Energy Centre and contributed to the increased operating margin in 2010. This was partly offset by reduced generation as a result of the sale of the Company's interest in the Battle River PPA in January 2010.

Clover Bar Energy Centre Unit 2 was offline from March 8, 2010 to September 22, 2010 due to a mechanical failure in the main turbine section. The Company recorded an estimated recovery of $8 million from business interruption insurance and the cost of the repair work on Unit 2 was covered by the original contractor. However, overall operating and maintenance expenses were higher as more Clover Bar Energy Centre units were in commission in 2010 and $8 million of maintenance expenses were incurred on the scheduled Genesee 3 outage in the fourth quarter of 2010. There were no similar outages in 2009.

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

The decrease in revenue from the Company's RRT business in 2010 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.

### Alberta contracted plants

Revenues for the Alberta contracted plants decreased primarily due to higher availability penalties incurred during the 21-day scheduled maintenance outage at Genesee 2 in the second quarter of 2010 compared with the availability penalties incurred during the 18-day scheduled maintenance outage at Genesee 1 in the fourth quarter of 2009. The penalties in 2010 were higher than anticipated due to higher pricing, which for availability incentive income and penalties is a function of a 30-day rolling average of Alberta power prices. This decrease was partly offset by higher revenues for generation in excess of committed capacity and increased recoveries of greenhouse gas (GHG) emission charges. The GHG emission recoveries from the Alberta Balancing Pool were based on the plants' emission intensity levels and offset the Company's cost of compliance with the Alberta Government's *Specified Gas Emitters Regulation* (SGER) for Genesee 1 and 2. The environmental compliance costs paid to Alberta Environment were included in operating costs. The net impact on the operating margin of the GHG charges and recoveries was not material. Higher maintenance costs for the Genesee 2 outage in 2010 compared with the Genesee 1 outage in 2009 contributed to a lower operating margin.

**Ontario and British Columbia contracted plants**

The higher revenues, gross margin and operating margin for the Ontario and British Columbia contracted plants primarily reflects the contribution from the Island Generation facility following its acquisition on October 19, 2010.

**CPILP plants**

Revenues, gross margin and operating margin for the CPILP plants decreased in 2010 compared with 2009 primarily due to lower foreign exchange rates, lower prices on settled foreign exchange contracts, lower waste heat sales at the Ontario facilities due to reduced waste heat availability, and lower revenue from the Kenilworth and Curtis Palmer plants. Revenue from the Kenilworth plant reflected lower fuel recoveries which were driven by lower natural gas supply prices, and revenue from the Curtis Palmer plant reflected lower water flows. These decreases in revenues were partly offset by higher pricing for power sales at the Ontario facilities and higher revenues at Oxnard in 2010 compared with 2009 as a result of the completion of the turbine upgrade which for accounting purposes was considered to be sold to the counterparty to the PPA. The gross margin and operating margin for the Ontario facilities were also reduced by higher prices for natural gas supplied under contract.

**Other portfolio activities**

The decrease in gross margin and operating margin for other portfolio activities was primarily due to net losses from natural gas trading activities in 2010 compared with net gains in 2009. Revenues for natural gas trading were also lower.

Fewer trading opportunities in the import and export electricity markets due to lower price spreads between markets and less volatility in prices in 2010, resulted in lower revenues in 2010 compared with 2009. However, the reduction in trading in the electricity markets did not have a material impact on gross margin and operating margin as these activities were only marginally profitable in 2009.

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

Changes in the fair value of CPLP's derivative electricity and natural gas contracts and natural gas storage held for trading, that were not designated as hedges for accounting purposes, decreased the gross margin by $26 million in 2010. These changes primarily reflected the reversal of prior years' gains associated with contracts that settled in 2010, partly offset by the impact of increases in Alberta forward power prices on portfolio positions. In 2009, the fair value changes of these instruments increased the gross margin by $83 million, reflecting the impact of decreases in Alberta forward power prices on portfolio positions.

CPILP's revenues included net gains of $8 million for changes in the fair value of foreign exchange contracts in 2010 compared with net gains of $59 million in 2009. The changes in fair value were primarily due to changes in the forward prices for U.S. dollars relative to Canadian dollars which decreased $0.039 in 2010 compared with $0.144 in 2009.

CPILP's fuel expense included losses of $12 million in 2010 compared with $52 million in 2009 for changes in the fair value of natural gas supply contracts. These changes in fair value primarily reflected decreases in Alberta future forward prices for natural gas of $1.65/Gj in 2010 and $1.02/Gj in 2009. In addition, CPILP designated certain of its natural gas contracts as hedges for accounting purposes effective July 31, 2009. Accordingly, a $59 million decrease in the fair value of the designated contracts was recorded in other comprehensive income in 2010 compared with a $9 million decrease in 2009.

## Consolidated Other Expenses

### Indirect administration

Indirect administration expenses include the cost of support departments and services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management and health and safety, as well as business development expenses including carbon capture and storage and integrated gasification combined cycle projects. Business development costs were lower in 2010 than in 2009. In addition, there were no costs incurred in 2010 comparable to the transition costs related to the Reorganization that were incurred in the second quarter of 2009. These decreases were offset by the recognition of the fair value of the obligation to EPCOR for the ongoing operations and maintenance costs, including a roof replacement, of the Rossdale plant and related assets in the third quarter of 2010. The fair value was estimated at $7 million based on the present value of the estimated future cash flows over the ten year term of the contract. See Critical Accounting Estimates and Policies.

### Net financing expenses

Financing expenses were $3 million lower for the year ended December 31, 2010 compared with the corresponding period in 2009. Capitalized interest was higher with no increase in borrowings until the latter part of the second quarter of 2010. The Company capitalizes borrowing costs as part of its capital construction projects and the amount capitalized is a function of the cost of the construction in progress. In the year ended December 31, 2010, construction work in progress, particularly for the Keephills 3, Port Dover & Nanticoke and Quality Wind projects, was higher compared with the corresponding period in 2009. Financing expenses also decreased due to the impact of a weaker U.S. dollar relative to the Canadian dollar on the translation of CPILP's U.S. dollar interest expense. These decreases were partly offset by unrealized losses of $6 million recognized in financing expenses in 2010 for the decrease in the fair value of two forward bond sale contracts. These contracts were entered into in the second quarter of 2010 and there were no similar contracts in 2009. See Liquidity and Capital Resources.

### Depreciation, amortization and asset retirement obligations accretion

Depreciation expense was $14 million higher for the year ended December 31, 2010 compared with the corresponding period in 2009. The increase was primarily due to depreciation for Island Generation commencing in the third quarter of 2010 and higher depreciation on Clover Bar Energy Centre. All three units at Clover Bar Energy Centre were operational in 2010 whereas only one unit was operational throughout 2009 and the two other units commenced operations in September and December 2009. In addition, depreciation expense for the second quarter of 2010 included a write-down of information technology assets.

### Foreign exchange losses

The foreign exchange losses for the years ended December 31, 2010 and December 31, 2009 were primarily related to the translation of U.S. monetary assets and liabilities. These losses were smaller in 2010 as the U.S. dollar weakened less in relation to the Canadian dollar in 2010 compared with 2009.

### Income taxes

Income taxes were lower primarily due to lower earnings before income taxes in 2010 compared with 2009. This was partly offset by the recognition in the third quarter of 2010 of an $11 million future income tax liability relating to the review of strategic alternatives regarding the Company's investment in CPILP. Since it was no longer apparent that the taxable temporary differences between the tax basis and accounting basis of the investment in CPILP would not reverse in the foreseeable future, the Company recognized the future income tax liability associated with these differences.

### Non-controlling interests

The non-controlling interests in CPILP reflect approximately 70.4% of CPILP net income which was lower in 2010 than in 2009. The non-controlling interests in CPLP reflected approximately 69.3% of the net income from CPLP which was lower in 2010 than in 2009. Non-controlling interests for the year ended December 31, 2010 also included 100% of the gain on sale of the Battle River PPA in the first quarter. The sale had an immaterial impact on the Company's net income attributable to common shareholders as their 27.8% share (at July 1, 2009) of the fair value of the Battle River PPA was recognized in the purchase price allocation for the Reorganization.

Income from CPLP included approximately 29.6% of the CPILP net income. Therefore the non-controlling interests in CPLP included approximately 20.5% (69.3% of 29.6%) of the CPILP net income.

## Non-GAAP Financial Measures

The Company uses (i) gross margin, (ii) operating margin, (iii) funds from operations, (iv) funds from operations excluding non-controlling interests in CPILP (v) normalized net income attributable to common shareholders, and (vi) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to Canadian GAAP and do not have standardized meanings prescribed by Canadian GAAP, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, cash flow from operating activities, earnings per share 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) | Year ended December 31, | |
|---|---|---|
| | 2010 | 2009 |
| Revenues | $ 1,760 | $ 2,158 |
| Energy purchases and fuel | 992 | 1,275 |
| **Gross margin** | **768** | **883** |
| Operations, maintenance, direct administration and property taxes | 248 | 228 |
| **Operating margin** | **520** | **655** |
| Indirect administration | 133 | 133 |
| Depreciation, amortization and asset retirement obligations accretion | 197 | 183 |
| Foreign exchange losses | 1 | 6 |
| Gains on acquisitions and disposals | (30) | (30) |
| Net financing expenses | 74 | 77 |
| Income taxes | 8 | 13 |
| Net income | **$ 137** | **$ 273** |
| Net income attributable to: | | |
| Non-controlling interests | $ 126 | $ 222 |
| Common shareholders | $ 11 | $ 51 |

Management considers operating margin to be representative of plant performance as it excludes indirect administration expenses which consist of corporate administration and business development expenses. The presentation of the pro forma consolidated information for the year ended December 31, 2009 conforms to the presentation adopted for the year ended December 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, $millions) | Year ended | Three months ended | | | | Six months ended | Three months ended | |
|---|---|---|---|---|---|---|---|---|
| | Dec 31, 2010 | Dec 31, 2010 | Sept 30, 2010 | June 30, 2010 | Mar 31, 2010 | Dec 31, 2009 | Dec 31, 2009 | Sept 30, 2009 |
| **Funds from operations excluding non-controlling interests in CPILP** | **$ 263** | **$ 62** | **$ 90** | **$ 36** | **$ 75** | **$ 124** | **$ 52** | **$ 72** |
| Funds from operations due to non-controlling interests in CPILP | 91 | 20 | 22 | 22 | 27 | 47 | 23 | 24 |
| Funds from operations | 354 | 82 | 112 | 58 | 102 | 171 | 75 | 96 |
| Change in non-cash operating working capital | 16 | (9) | 17 | (23) | 31 | 2 | 43 | (41) |
| **Cash provided by operating activities** | **$ 370** | **$ 73** | **$ 129** | **$ 35** | **$ 133** | **$ 173** | **$ 118** | **$ 55** |

**Normalized net income attributable to common shareholders and normalized earnings per share**

The Company uses normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings per share is based on net income attributable to common shareholders 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 and on unusual contracts. A reconciliation of net income (loss) attributable to common shareholders to normalized net income attributable to common shareholders, and earnings per share to normalized earnings per share is as follows:

| (unaudited, $millions except earnings (loss) per share) | Year ended | Three months ended | | | | Year ended | Three months ended | |
|---|---|---|---|---|---|---|---|---|
| | Dec 31, 2010 | Dec 31, 2010 | Sept 30, 2010 | June 30, 2010 | Mar 31, 2010 | Dec 31, 2009 | Dec 31, 2009 | Sept 30, 2009 |
| **Earnings (loss) per share** | **$0.50** | **$ (0.04)** | **$ 0.32** | **$ (0.37)** | **$ 0.60** | **$0.97** | **$ 0.33** | **0.64** |
| **Net income (loss) attributable to common shareholders** | **11** | **(1)** | **7** | **(8)** | **13** | **21** | **7** | **14** |
| Adjustments | | | | | | | | |
| Unrealized changes in fair value of CPLP's derivative instruments and natural gas held for trading | 8 | 2 | (1) | 7 | - | (8) | (5) | (3) |
| Unrealized changes in fair value of CPILP's derivative instruments | - | (1) | - | 1 | - | (2) | (1) | (1) |
| Venture capital investment write-down | - | - | - | - | - | 1 | 1 | - |
| Obligation to EPCOR for Rossdale plant | 2 | - | 2 | - | - | - | - | - |
| Acquisition loss for Island Generation acquisition | 6 | 6 | - | - | - | - | - | - |
| Change in prior quarters' adjustments, for change in non-controlling percentage interest | 1 | 1 | - | - | - | - | - | - |
| Income tax adjustments | 3 | (1) | 4 | 1 | (1) | 1 | 2 | (1) |
| | 20 | 7 | 5 | 9 | (1) | (8) | (3) | (5) |
| **Normalized net income attributable to common shareholders** | **31** | **6** | **12** | **1** | **12** | **13** | **4** | **9** |
| **Normalized earnings per share** | **$1.40** | **$ 0.26** | **$ 0.55** | **$ 0.05** | **$ 0.55** | **$ 0.60** | **$ 0.18** | **$ 0.42** |

The $6 million loss relating to the Island Generation acquisition is not reflective of performance in the period as it is a result of how income taxes are imposed on income from a partnership and the impact on the accounting for a bargain purchase gain in a business acquisition. If CPLP was taxable, rather than CPC being taxable on its income from CPLP, the accounting for the acquisition would have resulted in a goodwill asset on the balance sheet rather than a net loss attributable to common shareholders on the income statement.

The $1 million change in prior quarters' adjustments in the table above was recognized in the fourth quarter of 2010 and reflects the increase in the common shareholders' interest in the adjustments reported in previous quarters. This change was a result of EPCOR's conversion of partnership units to common shares as described under Significant Events.

## Balance Sheet

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

| (unaudited, $millions) | Dec 31, 2010 | Dec 31, 2009 | Increase due to Island Generation acquisition | Other increase (decrease) | Explanation of other increase (decrease) |
|---|---|---|---|---|---|
| Accounts receivable and income taxes recoverable | 277 | 304 | 2 | (29) | Primarily due to lower income taxes recoverable and lower receivables from EPCOR for RRT energy supply, partly offset by higher receivables from AESO for higher generation from Clover Bar Energy Centre and higher Alberta power prices, and a business interruption insurance receivable at December 31, 2010 relating to Clover Bar Energy Centre Unit 2. |
| Property, plant and equipment | 3,597 | 3,237 | 218 | 142 | Capital expenditures partly offset by depreciation and the impact of the strengthening Canadian dollar on the translation of property, plant and equipment of U.S. subsidiaries. |
| Power purchase arrangements | 464 | 528 | - | (64) | Primarily due to 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 | 203 | 184 | - | 19 | Primarily due to capital expenditures for rights to mine assets for Keephills 3, and expenditures for emission credits. |
| Net derivative instruments assets | 7 | 91 | - | (84) | Primarily due to decreases in the fair value of derivative instrument natural gas, power and forward bond sale contracts. |
| Accounts payable and accrued liabilities (1) | 304 | 339 | 3 | (38) | Primarily due to lower capital project accruals as Keephills 3 is nearing completion, Clover Bar Energy Centre was completed in December 2009 and capital expenditures for CPILP's North Carolina plant enhancement project were lower in the fourth quarter of 2010 compared with the fourth quarter of 2009. Partly offset by higher payables to AESO for energy purchases due to higher Alberta power prices. |
| Long-term debt (including current portion) | 1,869 | 1,719 | - | 150 | Primarily due to CPLP's medium-term notes issued in November 2010 and net drawings on CPLP's and CPILP's credit facilities, partly offset by debt repayments to EPCOR and a decrease in foreign exchange on the translation of CPILP's U.S. debt. |
| Net future income tax liabilities | 46 | 53 | 9 | (16) | Primarily future income tax impact of changes in the fair value of derivative contracts and an increase in losses carried forward for income tax purposes, partly offset by the recognition of future income tax liabilities relating to the review of strategic alternatives for the Company's investment in CPILP and relating to the increased ownership interest in CPLP. See Secondary Offering by EPCOR under Significant Events. |
| Non-controlling interests(1) | 1,754 | 2,046 | - | (292) | EPCOR's exchange of CPLP units for CPC shares and secondary offering of CPC shares, non-controlling interests' share of CPLP and CPILP distributions and other comprehensive loss, partly offset by non-controlling interests' share of CPLP and CPILP net income and CPILP unit issue. |
| Shareholders' equity | 824 | 489 | - | 335 | Exchange of CPLP units for common shares, issue of preferred shares, and net income, partly offset by common share dividends and other comprehensive loss. |

(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) | Year ended December 31, 2010 | Explanation |
|---|---|---|
| Cash from operating activities | $ 370 | See Funds from Operations |
| Investing | (503) | Capital expenditures, primarily for property plant and equipment, and the Island Generation acquisition, partly offset by proceeds on the sale of the final interest in the Battle River PPA in January 2010. |
| Financing | 140 | Issue of $300 million medium term notes and $125 million preferred shares in the fourth quarter and net drawings under CPLP's and CPILP's credit facilities, partly offset by debt repayments to EPCOR, distributions to non-controlling interests, and dividends paid to common shareholders. |

In June 2010, CPLP made the following debt repayments to EPCOR: $200 million of 6.95% debt and $45 million of 9% debt. In the second quarter of 2010, CPLP entered into two $100 million forward bond sale transactions which hedged a portion of the exposure to interest rate risk on the $300 million medium-term notes issued in November 2010 as discussed under Significant Events. These forward contracts were terminated in February 2011.

In the fourth quarter of 2010, Capital Power Corporation completed a $125 million preferred share offering, as described under Significant Events. The proceeds of the preferred share offering were lent to CPLP and CPLP thereby used the funds as well as proceeds from the medium-term notes to repay a portion of the balance outstanding under its credit facilities. The draws on the credit facilities had been used to fund the acquisition of Island Generation, and for general corporate purposes. In 2010, CPLP made a net draw of $117 million under its credit facilities, primarily to finance the debt repayments in June, and to fund capital expenditures.

In 2010, CPILP made a net draw of $8 million under its revolving credit facilities. CPILP's outstanding long-term debt also reflects a decrease of $23 million for the year for foreign exchange on the translation of its U.S. dollar denominated debt.

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

| | Carrying amount at December 31, | | | |
|---|---|---|---|---|
| (unaudited, $millions) | 2010 | 2009 | Maturity date | Nominal interest rate |
| Long-term debt payable to EPCOR | $ 619 | $ 872 | Ranging from 2011 to 2018 | Ranging from 5.80% to 9.00% |
| CPLP medium-term notes | 300 | - | 2020 | 5.28% |
| 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 | 217 | 100 | 2013 | Floating(1) |
| CPILP long-term debt | 699 | 715 | Ranging from 2012 to 2036 | Fixed ranging from 5.87% to 11.25% and floating(1) |
| | $ 1,882 | $ 1,734 | | |

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

On December 31, 2010, CPLP had $1,220 million of credit facilities, of which $500 million may be utilized for issuing letters of credit. On December 31, 2010, CPLP had $217 million of debt and $122 million of letters of credit outstanding under its credit facilities and $881 million remained available. Accordingly, CPLP has adequate credit facilities to cover the principal repayments of $235 million in 2011 which are required under the terms of its long-term debt agreements.

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. Some of the indebtedness of CPLP to EPCOR mirrors certain debt obligations of EPCOR to the public and has repayment and interest rate terms that correspond with EPCOR's mirrored debt. The remainder of the indebtedness of CPLP to EPCOR includes an amount sufficient to meet certain debt obligations of EPCOR related to indebtedness of The City of Edmonton assumed by EPCOR, and will be repaid in accordance with an amortization schedule. On or after December 2, 2012, if EPCOR no longer owns, directly or indirectly, at least 20% of the outstanding limited partnership units of CPLP, then EPCOR may, by written notice to CPLP, require repayment of all or any portion of the outstanding principal amount and accrued interest thereon. If the principal amount specified in such repayment notice is less than $200 million, then it and the accrued interest thereon shall be payable 180 days after delivery of notice, and if it is $200 million or more, then it and the accrued interest thereon shall be payable 365 days after delivery of notice.

CPLP's credit facilities include a Syndicated Facility of up to $700 million and an extendible revolving club credit facility (Club Facility) of up to $500 million. In the second quarter of 2010, these credit facilities were extended to July 2013. 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. CPLP also has revolving demand credit facilities totaling $20 million.

The Syndicated Facility, the Club Facility and the credit agreement with EPCOR require CPLP to meet certain financial covenants, including maintaining a consolidated senior debt to consolidated capitalization ratio of not more than 0.65 to 1.0 as at the end of any fiscal quarter. In addition, in the event that CPLP is assigned a credit rating by S&P that is less than BBB- or by DBRS that is less than BBB(low) (in each case with a stable outlook), then CPLP must also maintain a ratio of consolidated EBITDA (earnings before interest, income tax, depreciation and amortization) to consolidated interest expense (each as defined in the credit agreement with EPCOR) of not less than 2.5 to 1.0 as at the end of each fiscal quarter. The Syndicated Facility, the Club Facility and the credit agreement with EPCOR also prohibit CPLP from making distributions if an event of default has occurred and is continuing, or would reasonably be expected to result from the distribution. These agreements also contain provisions for default, including on a change of control. In the event that a change of control occurs, then if (i) in the case of the Syndicated Facility and the Club Facility, immediately thereafter the long-term senior unsecured and unsubordinated debt rating of CPLP is BBB- or higher from S&P and BBB(low) or higher from DBRS, in each case with a stable outlook, (i.e. investment grade), the lenders will have the option to elect to shorten the term of the facility to the lesser of 364 days and the then current maturity date, and (ii) immediately thereafter the debt rating of CPLP is not investment grade, it shall constitute an event of default unless the change of control is consented to by the lenders within a specified number of days after the occurrence thereof. Change of control means (i) a change in the general partner of CPLP unless such new general partner is an affiliate of Capital Power Corporation or EPCOR, or (ii) if any person, or group of persons acting jointly or in concert, acquires beneficial ownership of securities of Capital Power Corporation or the general partner of CPLP to which are attached 50% or more of the votes that may be cast to elect directors thereof, but excluding for greater certainty any such acquisition of securities by Capital Power Corporation, EPCOR or their affiliates.

On December 31, 2010, CPILP had credit facilities of approximately $365 million, and had $86 million of long-term debt borrowings and $1 million of letters of credit outstanding under these facilities. Accordingly, CPILP has sufficient funds available with $278 million of credit facilities available at December 31, 2010 and no long-term debt repayments due in 2011.

These credit facilities included two revolving facilities of $100 million each and one revolving facility of $125 million. By the end of 2010, CPILP had extended all three of its credit facilities to 2012. These facilities have 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.

Under the terms of its debt agreements, CPILP must maintain a debt to capitalization ratio of not more than 65% at the end of each fiscal quarter. In addition, under the revolving credit facilities, in the event CPILP is assigned a rating of less than BBB+ by S&P and BBB(high) by DBRS, CPILP would be required to maintain a ratio of EBITDA to interest expense of not less than 2.5 to 1, measured quarterly. Although CPILP was not required to meet the EBITDA to interest ratio, the ratio was 4.1 as at December 31, 2010. CPILP was compliant with all of its debt covenants under its debt agreements for the years ended December 31, 2010 and December 31, 2009. If an event of default occurs and continues under CPILP's credit facilities, CPILP may not declare, make or pay distributions, subject to certain limited exceptions.

CPLP's and CPILP's committed 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. In addition, Capital Power Corporation had an undrawn bank line of credit of $5 million at December 31, 2010.

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 within the BBB rating category which is the fourth highest rating of S&P's ten corporate credit ratings, which range from AAA to D. 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. S&P's ratings outlook is stable which reflects their expectation that CPLP will maintain its business risk profile in the long-term.

The BBB rating assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations, which range from AAA to D. 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. The outlook trend for this rating is stable as DBRS believes credit metrics will remain within a range consistent with the current ratings.

Credit ratings are intended to provide investors with an independent assessment of the credit quality of an issue or an issuer of securities and such ratings do not address the suitability of a particular security for a particular investor. The ratings assigned to a security may not reflect the potential impact of all risks on the value of the security. A rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

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) | | Total project capital expenditures | | |
|---|---|---|---|---|
| | Capital expenditures for the year ended Dec 31, 2010 | Incurred to Dec 31, 2010[1] | Total cost estimate[2] | Target or actual completion date |
| CPLP | | | | |
| Keephills 3 | $ 217 | $ 892 | $ 955 | 2nd quarter 2011 |
| Quality Wind and Port Dover & Nanticoke | 44 | 46 | 795 | 4th quarter 2012 |
| Other | 56 | | | |
| Total CPLP | 317 | | | |
| CPILP | | | | |
| North Carolina plants enhancement | 12 | 91 | 96 | 2011 |
| Other | 8 | | | |
| Total CPILP | 20 | | | |
| Total capital expenditures | 337 | | | |

(1) Total project capital expenditures incurred to December 31, 2010 reflect capital expenditures since the inception of the project.

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

Capital expenditures for Keephills 3 in 2010 were approximately $32 million lower than forecasted in the December 31, 2009 MD&A as approximately $27 million of expenditures were deferred to 2011, approximately $1 million of expenditures were determined to be non-capital and approximately $4 million was related to lower capitalized interest. Despite the deferral of certain expenditures to 2011, construction of Keephills 3 remains on target to the total project cost forecast and schedule as revised in October 2009. At that time the Boards of Directors of Capital Power and TransAlta approved additional funding for the project such that the total project cost was revised to $1.9 billion and Capital Power's share was revised to $955 million. The Company expects that the plant will commence commercial operations by the end of the second quarter of 2011.

Capital expenditures in 2010 for the new wind development projects reflect deposits made to the supplier of the wind turbines and commencement of construction on the Quality Wind project. The Company is pursuing the permitting process for the Port Dover & Nanticoke project. The capital expenditures for the fourth quarter of 2010 for these projects were $7 million lower than anticipated in the September 30, 2010 MD&A as certain expenditures were deferred to 2011. However, the projects remain on target for their total project cost forecast and schedule.

CPILP completed the Roxboro and Southport North Carolina plant enhancements in 2010 and plans to invest an additional $5 million in 2011 for final testing and the construction of access roads at the Southport facility. The road construction was rescheduled from 2010 to after the completion of the PPA arbitration process. CPILP's Oxnard turbine replacement project was completed in the fourth quarter of 2010 and for accounting purposes it was considered to have been sold to the facility's PPA counterparty, Southern California Edison Company (SCEC). The PPA is a capital lease for accounting purposes as all the power output from the facility is sold to SCEC under the PPA.

The Company's capital expenditures included in the other category in the table above are primarily for the improvement of existing facilities, a $10 million deposit made to the turbine supplier for Kingsbridge II which is transferable to the Quality Wind and Port Dover & Nanticoke projects and $16 million for environmental offsets.

**Future cash requirements – excluding CPILP**

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's estimated cash requirements for 2011, excluding CPILP's cash requirements and cash requirements for acquisitions, are expected to include approximately $379 million for capital expenditures, approximately $68 million for interest on long-term debt, approximately $60 million for CPLP distributions to EPCOR, subject to approval by the CPLP Board of Directors, approximately $39 million for Capital Power's quarterly common share dividends, subject to approval by the Capital Power Corporation Board of Directors, and approximately $6 million for its quarterly preferred share dividends. The current portion of long-term debt on the balance sheet of $235 million is primarily comprised of $233 million payable to EPCOR.

The Company expects to fund the construction of the Quality Wind and Port Dover & Nanticoke wind projects using existing bank credit facilities. Once construction is complete, the Company expects to put long-term financing in place while maintaining the Company's overall leverage in the range of 40% to 50%.

In April 2010, the Company filed two short form base shelf prospectuses which, market conditions permitting, provide the Company with the ability to obtain new debt and equity capital from external markets at the time of a requirement for a major investment of capital. Pursuant to one of the short form base shelf prospectuses Capital Power may raise up to $1 billion by issuing common shares, or subscription receipts exchangeable for common shares or other securities of the Company. If and when EPCOR exchanges its exchangeable partnership units of CPLP for common shares of the Company, they may sell their common shares under the base shelf prospectus as a secondary offering. As discussed under Significant Events, EPCOR sold 9.2 million common shares of Capital Power as a secondary offering under this base shelf prospectus. Pursuant to the other short form base shelf prospectus, CPLP may raise up to $1 billion by issuing medium-term notes with maturities of not less than one year. As discussed under Significant Events CPLP's $300 million debt offering was issued under this short form base shelf prospectus. 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 2011 are expected to include approximately $30 million for capital expenditures, approximately $39 million for interest on long-term debt, approximately $97 million for distributions subject to approval by the CPILP Board of Directors and approximately $13 million for preferred share dividends of a subsidiary company. 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 2011 remain as planned, it is expected that the sources of capital will be cash on hand, cash provided by operating activities and use of existing credit facilities.

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

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

## Contractual Obligations

| | Payments Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| (unaudited, $ millions) | 2011 | 2012 | 2013 | 2014 | 2015 | Thereafter | Total |
| Acquired PPA obligations(1) | $ 88 | $ 90 | $ 93 | $ 96 | $ 101 | $ 530 | $ 998 |
| Capital projects(2) | 309 | 503 | - | - | - | - | 812 |
| Energy purchase and transportation contracts(3)(4) | 94 | 68 | 58 | 60 | 58 | 69 | 407 |
| Operating and maintenance contracts(5) | - | - | 5 | 5 | 5 | 33 | 48 |
| Operating leases | 2 | 5 | 5 | 5 | 5 | 68 | 90 |
| Environmental credits | 23 | 12 | 11 | 5 | 3 | 1 | 55 |
| Forward foreign exchange contracts and commodity contracts-for-differences | 84 | 6 | 1 | 5 | - | 2 | 98 |
| Long-term debt | 235 | 113 | 237 | 203 | 15 | 1,081 | 1,884 |
| Interest on long-term debt(6) | 107 | 91 | 84 | 78 | 65 | 408 | 833 |
| Asset retirement obligations(7) | - | - | 10 | 10 | 10 | 360 | 390 |
| Loan commitments | 6 | - | - | - | - | - | 6 |
| Other purchase obligations | 2 | - | - | - | - | - | 2 |
| Total | $ 950 | $ 888 | $ 504 | $ 467 | $ 262 | $ 2,552 | $ 5,623 |

(1) Capital Power's obligation to make payments on a monthly basis for fixed and variable costs under the terms of its acquired PPAs will vary depending on generation volume and scheduled plant outages.

(2) Capital Power's obligations for capital projects include Keephills 3, Quality Wind and Port Dover & Nanticoke.

(3) The natural gas purchase contracts have fixed and variable components. The variable components are based on estimates subject to variability in plant production. These contracts have expiry terms ranging from 2011 to 2016 with built-in escalators in the contracts' terms for pricing.

(4) The natural gas transportation contracts are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2011 to 2017.

(5) Operating and maintenance contracts are related to a 10 year service agreement for Quality Wind with expected commencement in November 2012 at a cost of approximately $5 million per year.

(6) Repayments of bankers' acceptances outstanding under CPLP's and CPILP's extendible credit facilities at December 31,

2010, are reflected in the year of the maturity of the respective credit facility.

(7) Capital Power's asset retirement obligations reflect the undiscounted cash flow required to settle obligations for the retirement of its generation plants and Genesee coal mine.

## Off-balance Sheet Arrangements

As at December 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 year ended December 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. In December 2010, a subsidiary of EPCOR exchanged 9,209,000 of its exchangeable limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis. As a result, at December 31, 2010, 47.416 million limited partnership units and accompanying special voting shares and one special limited voting share remained outstanding to EPCOR. See Significant Events.

The Company's long-term debt payable to EPCOR, which was also issued in connection with the Reorganization, was $619 million at December 31, 2010 compared with $872 million at December 31, 2009. The interest incurred on this debt was $51 million for the year ended December 31, 2010 and $30 million for the six months ended December 31, 2009, of which $44 million and $20 million, respectively, was capitalized as property, plant and equipment for construction work in progress over the corresponding periods. The remainder was included in net financing expense.

The Company's revenues for power sold to EPCOR for resale to its customers was $370 million for the year ended December 31, 2010 compared with $205 million for the six months ended December 31, 2009. The Company's revenues for power sold to the City of Edmonton were $29 million for the year ended December 31, 2010 and $14 million for the six months ended December 31, 2009. The Company's purchase of distribution and transmission services from EPCOR was $30 million and $13 million for the year ended December 31, 2010 and six months ended December 31, 2009, respectively. The Company also had various transactions with EPCOR pursuant to the agreements which provide for the continuity of operations and services following the separation of the business of Capital Power from EPCOR. All of the above transactions were in the normal course of operations and were recorded at the exchange values which were based on normal commercial rates.

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

The balances outstanding at December 31, 2010 and December 31, 2009 resulting from transactions with EPCOR were as follows:

| (unaudited, $ millions) | December 31, 2010 | December 31, 2009 |
|---|---|---|
| **Balance sheet** | | |
| Accounts receivable | $ 52 | $ 63 |
| Other assets | 7 | 8 |
| Property, plant and equipment | 44 | 20 |
| Accounts payable and accrued interest on debt | 16 | 13 |
| Long-term debt (including current portion) and other non-current liabilities | 622 | 872 |

## Business Risks

The Company's approach to risk management is to identify, monitor and manage the key controllable risks facing the Company and consider appropriate actions to respond to uncontrollable risks. Risk management includes the controls and procedures for reducing controllable risks to acceptable levels and the identification of the appropriate actions in cases of events occurring outside of management's control. Acceptable levels of risk for the Company are established by the Board of Directors and govern the Company's decisions and policies associated with risk. The Board of Directors reviews the Company's risk profile on a semi-annual basis and material changes to the risk profile on a quarterly basis.

Risk management is carried out at three levels. Firstly, the President and Chief Executive Officer (CEO) has ultimate accountability for managing the Company's risks and approves the framework for enterprise risk management. The President and CEO and the rest of the executive team provide general oversight and policy review and recommendation. They meet regularly to review enterprise risk management performance and to evaluate significant or emerging risks. Secondly, the Director, Risk Management and Internal Audit is responsible for the enterprise risk management framework including developing risk management policies and processes and monitoring the Company's compliance with the policies and processes. He is also responsible for the leadership of the commodity risk management (middle office) function. Thirdly, individual executive risk owners are accountable for carrying out the risk management and mitigation activities associated with the risks in their respective operations. Management views risk management as an ongoing process and continually looks for ways to enhance the Company's risk management processes.

The Company maintains an Ethics Policy which includes an Accounting and Auditing Complaint Procedure to provide for confidential disclosure of any wrong-doing relating to accounting, reporting and auditing matters. The policy prohibits any retaliation against a person making a complaint.

The following are risk factors relating to the Company and its business.

**Operations risk**

Power plant operations are susceptible to outages due to failure of generation equipment, transmission lines, pipelines or other equipment, which could make the affected plant unavailable to provide service. The inability of Capital Power's power plants to generate the expected amount of electricity to be sold under contract or to the applicable market could have a significant adverse impact on the Company's revenues. In addition, counterparties to PPAs have remedies available to them if Capital Power fails to operate facilities in accordance with contract requirements, including the recovery of damages and termination of contractual arrangements. To the extent that plant equipment requires significant capital and other operation and maintenance expenditures to maintain efficiency, requires longer than forecast down-times for maintenance and repair, experiences outages due to equipment failure or suffers disruptions of power generation for other reasons, Capital Power's cost of generating electricity will increase and/or Capital Power's revenues may be negatively affected. As an adopter of new technology, Capital Power can be exposed to design flaws or other issues, the impacts of which may not be covered by warranties or insurance. The failure of Capital Power's facilities to operate at required capacity levels may result in the facilities having their contracted capacity reduced and, in certain cases, Capital Power having to make payments on account of reduced capacity to power purchasers.

The Company's operational risks are partly mitigated by its, and the acquired PPA (Sundance) plant owner's operating and maintenance practices that are intended to minimize the likelihood of prolonged unplanned down time. The terms of the Company's PPAs, including its acquired PPA, provide appropriate incentives to owners to keep the plants well maintained and operational. They also provide force majeure protection for high-impact low probability events including major equipment failures. The Company's maintenance practices are augmented by an inventory of strategic spare parts, which can reduce down time considerably in the event of failure. The Company has also secured appropriate business interruption insurance to reduce the impact of prolonged outages caused by insured events.

In March 2010, Clover Bar Energy Centre Unit 2 went offline due to a mechanical failure in the main turbine section. See Results by Plant Category – Financial Results. In the fourth quarter of 2008, there was an unplanned outage at the Genesee Unit 3 facility due to a turbine rotor blade failure that kept the unit offline for 39 days. Examination and testing indicated that the failure was due to the use of lower grade material. Replacement blades of higher grade material have been installed.

**Electricity price and volume risk**

Capital Power's revenues are impacted by the market price for electricity in the jurisdictions in which Capital Power operates. Capital Power buys and sells some of its electricity in the wholesale markets of Alberta, Ontario, and the U.S. Such transactions are settled at the spot market prices of the respective markets. Market electricity prices are dependent upon a number of factors, including: the projected supply and demand of electricity; the price of raw materials that are used to generate electricity; the cost of complying with applicable regulatory requirements, including environmental; the structure of the particular market; and weather conditions. It is not possible to predict future electricity prices with complete certainty, and electricity price volatility could therefore have a material adverse effect on Capital Power.

Electricity sales associated with the PPA for Genesee 1 and 2 are accounted for as long-term fixed margin contracts, which limits the impact of swings in wholesale spot electricity prices, unless plant availability drops significantly below the PPA target availability for an extended period. Most of the Company's other plants, including Brown Lake, Miller Creek, Island Generation and Kingsbridge I, operate under long-term commercial contracts. Electricity sales and steam sales associated with the Joffre facility located at the Nova Chemicals Company (NOVA) petrochemical complex are subject to market price variability as there are provisions in the contract with NOVA that require the facility to run to provide steam to the host facility, irrespective of market prices. Although the Company's 50% interest in Genesee 3 is not covered by a long-term commercial contract, it is a base-load coal-fired generating plant with a relatively low variable cost and it will generally run when it is available. The profitability of Genesee 3 is impacted by electricity spot prices and the plant's variable costs, as well as planned and unplanned outages. The CPILP facilities generally operate under long-term power sales contracts, thereby reducing their electricity price and volume risks. The Company seeks to re-contract existing generation plants under new or extended contracts and its growth strategy includes maintaining approximately 50% of the Company's operating margin from contracted plants.

When aggregate customer electricity consumption (load shape) changes unexpectedly, Capital Power is exposed to price risk. Load shape refers to the different pattern of consumption between peak hours and off-peak hours. Consumption is higher during peak hours when people and organizations are most active; conversely, consumption is lower during off-peak hours. Capital Power attempts to minimize exposure to extreme price fluctuations, especially during higher priced peak hour periods. In order to do this, Capital Power relies on historical aggregate consumption data (load shape) provided by load settlement agents and local distribution companies to anticipate what aggregate customer electricity consumption will be during peak hours. When consumption varies from historical consumption patterns and from the volume of electricity purchased for any given peak hour period, Capital Power is exposed to prevailing market prices because it must either buy the electricity if it is short or sell the electricity if it is long. Such exposures can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.

In order to manage its exposure to spot price variability within specified risk limits, the Company enters into purchase and sale arrangements, including contracts-for-differences (CfD) and firm price physical contracts, for periods of varying duration. A CfD is an arrangement whereby a payment is made by one party to the contract to the other, based on the difference between a reference price and the market price of an underlying commodity such as electricity or natural gas. However, due to limited market liquidity and the variability of electricity consumption between peak usage hours and off-peak usage hours, it is not possible to hedge all positions every hour. The Company operates under specific policy limits, such as total exposure and stop-loss limits, and generally trades in electricity to reduce the Company's exposure to changes in electricity prices or to match physical or financial obligations.

**Energy supply risk**

Capital Power requires energy from sources such as coal, natural gas, water, wind, wood waste and waste heat to generate electricity. A disruption in the supply of, or a significant increase in the price of, any fuel supplies required by Capital Power could have a material adverse impact on Capital Power's business, financial condition and results of operation. The price of fuel supplies is dependent upon a number of factors, including: (i) the projected supply and demand for such fuel supplies; (ii) the quality of the fuel (particularly in regards to wood waste); and (iii) the cost of transporting such fuel supplies to Capital Power's facilities. Changes in any of these factors could increase Capital Power's cost of generating electricity or decrease Capital Power's revenues due to production cutbacks.

Coal for the Genesee and Keephills 3 plants is supplied under long-term agreements where the price is based on a cost-of-service model with annual updates for inflation, interest rate and capital budget parameters and is therefore not subject to coal market price volatility. A shortage of coal supply resulting from significant disruption of the coal mine equipment and operation could negatively impact generation and revenues from these plants. To mitigate this risk the Company and the joint venture maintain coal stock-pile inventories sufficient for approximately six weeks of operations.

Some of Capital Power's natural gas-fired plant operations are susceptible to the risks associated with the volatility of natural gas prices beyond any fixed price term. Natural gas purchases for several of Capital Power's power plants are made under variable price structures with fuel cost flow-through provisions. However, these power plants have PPAs extending for terms in excess of existing contractual supply arrangements. The failure to contract for additional fuel supply by the end of existing contract terms at acceptable prices may lead to a disruption in operations and an inability to perform under the power and steam purchase agreements.

The Company's hydroelectric facilities are dependent upon the availability of water. Variances in water flows, which may be caused by uncontrollable weather-related factors affecting precipitation, or by dam failure, could result in volatility of hydroelectric plant revenues.

Capital Power's wind power facilities are dependent on the availability and constancy of sufficient wind resources to meet generation capacity. Decreases in wind speed or duration could have a material negative impact on revenues for these facilities.

**Environmental risk**

Many of Capital Power's operations are subject to extensive environmental laws, regulations and guidelines relating to: the generation and transmission of electricity, pollution and protection of the environment, health and safety, air emissions, water usage, wastewater discharges, hazardous material handling and storage, treatment and disposal of waste and other materials, remediation of sites, and land-use responsibility. These regulations can impose liability for costs to investigate or remediate contamination. Further, there can be no assurance that compliance with and/or changes to environmental regulations will not materially adversely impact Capital Power's business, prospects, financial condition, operations or cash flow.

The Company's business is a significant emitter of carbon dioxide ($CO_2$), nitrogen oxide (NOx), sulphur dioxide ($SO_2$), mercury and particulate matter (PM), and is required to comply with all licenses and permits and federal, provincial and state requirements, including programs to reduce or offset GHG emissions. Compliance with new regulatory requirements may require Capital Power to incur significant capital expenditures or additional operating expenses, and failure to comply with such regulations could result in fines, penalties or the curtailment of operations. The Company complies with regulatory requirements while reducing environmental impact.

*Canadian Federal Government - Greenhouse Gas Regulation*

On June 23, 2010, the Canadian Environment Minister announced the Government of Canada's plan for new GHG emission regulation for coal-fired electricity generation units. The proposed plan will apply a new GHG emissions performance standard to new coal-fired electricity generation units and facilitate phasing out conventional coal-fired electricity generation in an orderly manner. The regulations are anticipated to be effective July 1, 2015 and units that have commercial operation dates prior to July 1, 2015 are expected to be exempt from the regulation until they reach the end of their economic useful life, which has been proposed at 45 years from commercial operation date. Because the proposed regulations allow existing coal-fired generation assets to operate for their economic life with no additional charges for GHG emissions anticipated, the regulations will not strand any existing coal investment but will establish a firm deadline by which emissions from existing coal units must be reduced through the application of new technology or the units must be shut down. These regulations are therefore expected to have little if any impact on Capital Power's Genesee units and Keephills 3. However, it is not possible to predict whether the regulations will be adopted as drafted or at all.

*Canadian Federal Government - Air Emission Regulations*

The Canadian government is considering regulations which may place stricter limits on NOx, $SO_2$, mercury and PM emissions from fossil-fired generating stations in Canada. The Canadian Department of Environment, in conjunction with the provincial governments, is working on the development of a regulatory framework under a Comprehensive Air Management System, to minimize local emissions. The regulations are expected to be implemented in 2013. There is insufficient information to assess the financial implication to Capital Power's operations, although as additional regulation is passed it is likely Capital Power will incur increased costs.

*Alberta - Greenhouse Gas Regulation*

The Specified Gas Emitters Regulation (SGER) under the *Climate Change and Emissions Management Act* (Alberta) came into force on August 1, 2007. The SGER is applicable to all facilities in Alberta that produce over 100,000 tonnes of GHG, measured as carbon dioxide equivalents ($CO_2$Es), per year. The Alberta Government recognizes three mechanisms for compliance with this regulation: (1) operational or plant changes to reduce emission intensity; (2) payment into the Alberta Government Climate Change Emission Management Fund (currently set at $15 per tonne) for all emissions in excess of the emission intensity target; and (3) purchase of GHG emissions offsets created from Alberta based projects. The SGER imposes a $CO_2$E intensity reduction of 12% from the average $CO_2$E emissions intensity based on the 2003 to 2005 period.

The approximate cost associated with compliance with the SGER for Genesee Units 1 and 2 for the 2010 compliance period was $5 million ($5 million for 2009). These costs were recoverable from the PPA holder under the terms of the PPA. The cost is estimated to be approximately $6 million per year in the future, which will also be recoverable from the PPA holder. The compliance cost associated with the Sundance Units 5 and 6 PPA is passed on to Capital Power, as the PPA buyer, in proportion to its ownership interest and will be approximately $5 million for the 2010 reporting period ($4 million for 2009) for Capital Power and for EPCOR prior to July 1, 2009. The first GHG targets for Genesee 3 began in 2009 following a three-year grace period and the target reductions are graduated starting at 2% per annum and increase at a rate of 2% per annum. Therefore the 2010 and 2009 targets were 4% and 2% respectively, and equated to approximately 30,000 tonnes and 35,000 tonnes, respectively for Capital Power's (and EPCOR's prior to July 1, 2009) 50% share. The compliance obligation was lower in 2010, compared to 2009, as a result of the scheduled outage at Genesee 3 in October 2010.

The Company is also required to offset Genesee 3's GHG emissions by approximately 53% under Clause 10 of EUB Decision 2001-111, which forms part of Genesee 3's original operating approval. This reduction obligation is in addition to the SGER obligations. In 2010, Capital Power applied to the Alberta Utilities Commission (AUC) seeking relief from the Clause 10 offset requirement. In January 2011, the AUC denied the application, concluding that the SGER was not intended to supersede or replace Clause 10, and that Capital Power must continue to meet both GHG offset requirements. The AUC decision does not impose any new reduction targets or costs for Genesee 3. Offsets have been retired every year since the plant was commissioned, and compliance costs under Clause 10 have not been material. The compliance cost for Genesee 3 under the SGER and Natural Gas Combined Cycle offset for 2010 is expected to be approximately $1 million ($1 million for 2009).

Capital Power (EPCOR prior to July 1, 2009) has been purchasing offsets for seven years and has entered into more than 25 offset purchase agreements. Approximately $16 million worth of offsets were purchased in 2010 ($10 million in 2009). Approximately 540,000 tonnes of offsets were applied against Capital Power's 2009 compliance obligations associated with the Sundance and Battle River PPAs which, compared to purchasing credits through the Climate Change Emission Management Fund, resulted in a savings to Capital Power of approximately $4 million. The amount of offsets applied against the 2010 compliance obligations will be determined by the reporting deadline of March 31, 2011.

The current SGER will expire in 2014 and it is not clear whether the proposed federal GHG emission regulations will replace the SGER.

*Alberta - Air Emission Regulations*

In 2009, Capital Power participated with industry, government and non-government organization stakeholders in the five-year Clean Air Strategic Alliance (CASA) Review of the Alberta Electricity Framework. The CASA project team has proposed emission limits for NOx, $SO_2$, PM and mercury for new coal-fired units or existing units at the end of their economic life. If these recommendations are adopted they will have no impact on Capital Power's existing facilities. The project team and Alberta Environment are also reviewing potential emission standards for existing coal-fired units and for gas-fired units.

The Government of Alberta regulations require coal-fired plant operators, including Capital Power, to monitor mercury emissions and capture at least 70% of the mercury in the coal starting January 1, 2011. During 2009 and 2010, the Company installed and tested an activated carbon injection system and mercury Continuous Emission Monitoring System on Genesee Units 1, 2, and 3 to meet the regulatory requirements.

*Ontario*

The Ontario government aims to harmonize its cap and trade program with the Western Climate Initiative (WCI), which is represented by four provinces (B.C., Ontario, Quebec and Manitoba) and eleven states. The WCI requires a 15% reduction in GHG emission levels by 2020, from those of 2005. The cap and trade system applicable to industrial facilities including electricity generation is expected to start in 2012. However, the Ontario Government has not yet provided the industry specific GHG reduction targets or other program details. There is insufficient information to assess the financial implication to Capital Power's operations.

*B.C.*

*The Greenhouse Gas Reduction Targets Act* and the *Greenhouse Gas Reduction (Cap and Trade) Cap and Trade Act* which were enacted in 2008, provide the statutory basis for establishing a market-based framework to reduce GHG emissions from large emitters. The BC Government aims to harmonize its cap and trade program with the WCI, similar to Ontario. The cap and trade system applicable to industrial facilities, including electricity generation, is expected to start in 2012 and will replace the current fuel tax. However, the BC Government has not yet provided the industry specific GHG reduction targets or other program details. There is insufficient information to assess the financial implication to Capital Power's operations.

*U.S. - Greenhouse Gas Regulation*

The U.S. Environmental Protection Agency (USEPA) and the state of California have implemented mandatory GHG reporting requirements, which are expected to be met by the Company on their respective due dates in 2011.

The USEPA is expected to regulate GHGs under the *Clean Air Act* (CAA) with requirements for best available control technology for new GHG sources and major modifications of existing sources. They also plan to control GHG emissions for existing and new sources through new source performance standards.

The WCI, described above under Ontario, may impact the operation of CPILP's four facilities in California, and its Frederickson facility in Washington.

California's proposed cap and trade program to control GHGs aims to cut the state's GHG emissions to 1990 levels by 2020 with further reductions each year thereafter. The initial phase of the program will apply to electric generation and large industrial units and is expected to be effective in January 2012, but the proposal's GHG emission allocation methodology has not yet been established. On November 2, 2010, a proposition to effectively repeal the program was rejected by California voters. There is insufficient information to assess the financial implication to Capital Power's operations.

*U.S. - Air Emission Regulations*

In July, 2010, USEPA proposed the *Clean Air Transport Rule* (CATR) to replace the Clean Air Interstate Rule. CATR proposes to reduce the amount of NOx and $SO_2$ emissions from electric generating units that are transported in the air to down-wind states. CATR proposes emission reductions sufficient to contribute to reducing NOx and $SO_2$ measures below the ambient air quality standards in those down-wind states. The CATR proposals are also expected to significantly limit emission trading.

CATR only applies to units of generating facilities with a capacity of 25 MW or more, although it may be extended to other facilities when it is re-evaluated in 2014. Cogeneration facilities and units not providing electricity for sale on the electricity grid are also exempt. However, details of the proposed regulations are limited at this time.

In 2010, the USEPA proposed new air toxics standards, including standards for mercury, for industrial boilers and for coal and oil-fired electric generating units. However, the state of North Carolina issued a maximum available control technology permit to CPILP under the CAA, which precludes the application of these proposed new standards to its North Carolina facilities. In addition, based on the fuel mix and newly installed controls at CPILP's North Carolina facilities, the Company does not anticipate the need for further mercury or other hazardous emissions controls at these facilities.

*U.S. - Comprehensive Environmental Response, Compensation and Liability Act*

The *Comprehensive Environmental Response, Compensation and Liability Act* (CERCLA), also referred to as Superfund, requires investigation and remediation of sites where there has been a release or threatened release of hazardous substances. It also authorizes the USEPA to order parties who are potentially responsible for the release, to pay for their actions. Many states have similar laws. CERCLA defines potentially responsible broadly to include past and present owners and operators, as well as generators, of wastes sent to a site. Capital Power is currently not subject to any material liability for any Superfund matters. However, Capital Power generates certain wastes, including hazardous wastes, and sends certain of its wastes to third party waste disposal sites. As a result, there can be no assurance that Capital Power will not incur a liability under CERCLA in the future.

*Capital Power Initiatives*

As part of its strategy to reduce its GHG emissions and to be better positioned for compliance with future regulation, the Company has a focus on technology to reduce $CO_2$ from coal generation. The Genesee 3 plant and the Keephills 3 facility currently under construction use supercritical coal-burning technology which will emit 24% less $CO_2$ in producing the same amount of power as the four Wabamun units recently retired by TransAlta.

In addition, the Company participated in a $33 million research project to complete a front-end engineering design (FEED) study of a clean coal project. The Company, Alberta Inovates and National Resources Canada each contributed $11 million to the study. The FEED study was completed in early 2010 and the results indicate that this technology is currently uneconomical.

The Company is partnering with TransAlta, Enbridge and Alstom Canada to develop one of the world's largest carbon capture and storage (CCS) projects as part of Keephills 3 which will be designed to capture approximately 1 million tonnes of GHG emissions annually, called Project Pioneer. TransAlta is the lead on the project which is currently in the FEED stage. After the FEED stage has been completed, which is expected to be by the end of the second quarter of 2011, the Company will decide whether to proceed with construction. The project has signed a letter of intent with the Province of Alberta to receive funding from the province's $2 billion CCS fund. The Government of Canada is also contributing toward the project through its Clean Energy Fund.

**Acquisition and development risk**

In the course of assessing development and acquisition opportunities, Capital Power may be required to incur significant expenditures, such as those related to preliminary engineering, permitting, legal and other expenses, prior to determining whether a project is feasible and economically viable. There can be no assurance that Capital Power will pursue or win any opportunity assessed.

The risks associated with acquisitions of additional companies or assets in the power generation industry include the failure to identify material problems during due diligence, the risk of over-paying for assets and the inability to arrange financing for an acquisition. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will support the indebtedness incurred to acquire them or the capital expenditures needed to develop them.

In developing a power generation facility, there are numerous tasks Capital Power must complete, including obtaining: government permits and approvals; site agreements; construction contracts; access to power grids, and electrical transmission agreements; fuel supply and transportation agreements; equipment; and financing. There can be no assurance that Capital Power will be successful in completing such tasks on a timely basis or at all. The development and future operation of power generation facilities can be adversely affected by changes in government policy and regulation, environmental concerns, increases in capital costs, increases in interest rates, competition in the industry, labour availability, labour disputes, increases in material costs and other matters beyond the direct control of Capital Power. In the event that a project is not completed or does not operate at anticipated performance levels, Capital Power may not be able to recover its investment.

The Company attempts to mitigate these risks by performing detailed project analyses, risk assessments and due diligence prior to and during construction or acquisition. Corrective actions are taken when necessary to increase the likelihood of investment recovery. The Company also seeks to enter into favourable long-term contracts for the projects' output whenever possible.

**PPA contract risk**

Many of Capital Power's generation plants operate under PPAs, which are subject to a number of risks. PPA contracts contain performance benchmarks that must be achieved and other obligations that must be complied with by Capital Power. Capital Power may incur charges in the event of unplanned outages or variations from the contract performance benchmarks. Electricity sales are accounted for as long-term fixed margin contracts, which limit the impact of swings in wholesale spot electricity prices, unless plant availability drops significantly below the PPA target availability for an extended period. PPAs expire at various times and there can be no assurance that a subsequent PPA will be available or, if available, that it will be on terms, or at prices that permit the operation of the facility on a profitable basis.

**Counterparty risk**

Counterparty risk is the possible financial loss associated with the potential inability of counterparties to satisfy their contractual obligations to Capital Power, including payment and performance. In the event of default by a purchasing counterparty, existing PPAs and steam purchase agreements may not be replaceable on as favourable terms. Capital Power is also dependant upon counterparties with respect to its cogeneration hosts and suppliers of fuel to its plants. In the wholesale electricity market, should a counterparty default, Capital Power may not be able to effectively replace such counterparty in order to manage short or long electricity positions, resulting in reduced revenues or increased power costs. Furthermore, a prolonged deterioration in economic conditions could increase the foregoing risks.

The Company's risk management program includes a credit policy which has been approved by the Board of Directors. The credit policy establishes limits for credit risk exposure levels and provides the framework for counterparty credit risk management activities within the Company. The credit review procedures require assessment of individual counterparty creditworthiness and establishment of a credit limit prior to entering into a transaction with the counterparty. Periodic credit reviews are also conducted on existing counterparties with which the Company has credit exposure. The Company uses credit enhancements such as cash deposits, parent company guarantees and bank letters of credit as well as master netting agreements, margin accounts and credit derivatives to mitigate its credit risk. The credit management procedures also provide for monitoring the Company's credit risk exposures and regular reporting to the executive team.

**Sundance PPA risk**

The occurrence of an event which disrupts the ability of the Sundance power plants to produce or sell power or thermal energy for an extended period under the Sundance PPA would likely require Capital Power to replace the electricity at market rates prevailing at that time. However, it would be relieved of the obligation to pay the unit capacity fee. Depending on market liquidity, these market prices could be significantly higher than the prices inherent in the Sundance PPA, thus increasing the cost of energy purchases to Capital Power.

**Political, legislative and regulatory risk**

Capital Power is subject to risk associated with changing political conditions and with federal, provincial, state, local or common law and regulations. It is not possible to predict changes in the regulatory environment or their impact on the Company's business, income tax status or operations. Capital Power is also required to maintain numerous licenses, permits and governmental approvals for the operation of its projects. If Capital Power fails to satisfy the conditions of these instruments, the operation or cost of the affected projects, could be adversely affected. Many of the regulatory approval processes for the development, construction and operation of power generation facilities require stakeholder input. Accordingly, progress in Capital Power's development, construction and operation activities could be impeded by stakeholder intervention.

**Health and safety risk**

The development, construction, ownership and operation of Capital Power's generation assets carry an inherent risk of liability related to public health and worker health and safety. Capital Power's operations are also subject to the risks of a pandemic illness that could disrupt its operations.

The Company manages its health and safety risks through a company-wide health and safety management system and measures its health and safety performance against recognized industry and internal performance measures. Compliance audits are conducted by internal and external auditors to verify that the health and safety management system meets the regulatory requirements for the business. The Company has plans to respond to a potential pandemic to help maintain a sufficient healthy workforce and enable the Company to deliver reliable power to customers in such an event.

**Liquidity risk**

Capital Power's acquisition, future development or enhancement opportunities may require additional financing from time to time. The ability of Capital Power to refinance existing indebtedness and arrange additional financing in the future will depend in part upon prevailing market conditions at the time as well as the business performance of Capital Power. Uncertainty and volatility in the Canadian and U.S. financial markets, may adversely affect Capital Power's ability to arrange financing for capital expenditures and acquisitions and to refinance indebtedness at their maturity dates. This may affect the Company's credit ratings. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet the Company's financing requirements. The inability of Capital Power to access sufficient amounts of capital on terms acceptable to Capital Power for its operations could have a material adverse effect on Capital Power's business, prospects and financial condition. See Liquidity and Capital Resources.

**Reliance on transmission systems risk**

Capital Power depends on transmission facilities owned and operated by third parties to deliver the wholesale power from its power generation plants to its customers. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, Capital Power's ability to sell and deliver wholesale power may be adversely impacted.

Capital Power's ability to develop new projects is also impacted by the availability of transmission and distribution systems. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure. Capital Power cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets. In the Company's relationships with regulators and government it supports the timely development of appropriate transmission capability.

**Dependence on CPLP, operating subsidiaries and CPILP risk**

The Company is dependent upon cash dividends, distributions or other transfers from CPLP, its subsidiaries and CPILP in order to repay any debt the Company may incur, make dividend payments to its shareholders and meet its other obligations. The right of the Company, as a unit holder or shareholder of these entities, to realize on the assets of these entities in the event of their bankruptcy or insolvency would be subordinate to the rights of their creditors and claimants preferred by statute. CPLP's credit facilities prohibit CPLP from making distributions if an event of default has occurred and is continuing or would reasonably be expected to result from the distribution. As noted under Significant Events - $125 million Offering of 4.60% Cumulative Rate Reset Preference Shares, the Company has loaned certain amounts to CPLP under a subordinated debt agreement. The terms of this agreement allow interest to be deferred. If interest is deferred, then CPLP has covenanted not to make distributions on any of its outstanding limited partnership units. Under CPILP's revolving credit facilities, CPILP may not declare, make or pay distributions (subject to certain limited exceptions) in the event of default under such facilities. In addition, CPILP may not make any distributions if the declaration of dividends on preferred shares issued by a CPILP subsidiary is in arrears.

**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 also maintains natural gas in storage for trading and for managing natural gas needs. The inventory is held for resale in current or forward markets and is subject to the volatility of natural gas prices.

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 trading risks associated with the 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 at a given level of confidence. Capital Power's 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 limits, the portfolio is stress-tested regularly to observe the effects of plausible scenarios taking into account historical maximum volatilities and observed price movements.

**Income tax risk**

Capital Power's operations are complex and the computation of the provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. In addition, Capital Power's tax filings are subject to audit by taxation authorities. While Capital Power believes that its tax filings have been made in accordance with all such tax interpretations, regulations, and legislation, Capital Power cannot guarantee that it will not have disagreements with taxation authorities with respect to Capital Power's tax filings.

**General economic conditions, business environment and other risks**

In addition to all of the risks previously described, the Company is subject to adverse changes in its markets and general economic conditions. The Company is exposed to risks associated with the development and retention of a qualified workforce, technology, weather, fluctuations in foreign exchange rates, market competition, lawsuits, risks that are not fully covered by various insurance policies or the risk that the Company is unable to comply with the changes to the new IFRS reporting requirements on a timely basis. These risks could have an adverse impact on Capital Power's business, prospects, financial condition, results of operation or cash flows.

Capital Power's ability to continuously operate its facilities and grow the business is dependent upon retaining and developing sufficient labour and management resources. Capital Power is facing a demographic shift as a significant number of its employees are expected to retire over the next several years**.** Failure to secure sufficient qualified labour may negatively impact Capital Power's operations or construction and development projects, or may increase expenses. The Company employs good human resource practices including monitoring developments and reviewing its strategies in human resources.

Capital Power's current collective bargaining agreements expire periodically and Capital Power may not be able to renew them without a labour disruption or without agreeing to significant increases in labour costs.

Ongoing research and development activities improve upon existing power technologies and reduce the cost of alternative methods of power generation. Capital Power's plants may over time be unable to compete with newer more efficient plants utilizing these new technologies.

Capital Power employs several key computer application systems to support its operations, such as electricity plant control systems and electricity settlement and billing systems. Failure of any of these systems could result in lost revenue or regulatory fines. The Company has security measures to mitigate the risk related to loss of data due to theft or corruption. In addition, system recovery programs are in place to minimize any losses experienced as a result of a computer application system shutdown.

Weather can have a significant impact on Capital Power's operations. Temperature levels, seasonality and precipitation, both within Capital Power's markets and adjacent geographies, can affect the level of demand for electricity and natural gas, thus resulting in electricity and natural gas price volatility. Capital Power's operations are exposed to potential damage resulting from extreme weather conditions and natural disasters. Financial exposures associated with extreme weather are partially mitigated through the Company's insurance programs.

Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar affect Capital Power's capital and operating costs, revenues and cash flows and could have an adverse impact on Capital Power's financial performance and condition. The U.S. plant operations and the foreign-sourced equipment required for capital projects are transacted in U.S. dollars. In addition, certain indebtedness is denominated in U.S. dollars.

The foreign exchange risk of anticipated U.S. dollar denominated cash flows, net of debt service obligations, is managed through the use of forward foreign exchange contracts for periods of up to six years. In addition, significant equipment purchases or borrowings are generally fixed in Canadian dollars by contracting in Canadian dollars or using forward foreign exchange contracts.

In the normal course of Capital Power's operations, it may become involved in various legal proceedings including arbitration of the interpretation of any contract. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty. However, the Company does not believe that the outcome of any claims or potential claims of which it is aware will have a material adverse effect on Capital Power's financial condition and results of operations.

Capital Power's property, business interruption and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these and other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis or that all events that could give rise to a loss or liability are insurable.

There can be no assurance that any risk management steps taken by Capital Power with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

**Risks related to significant ownership by EPCOR**

For so long as EPCOR maintains a significant indirect equity and voting interest in the Company, EPCOR will have the ability to significantly influence the outcome of shareholder votes, including the ability to prevent certain fundamental transactions. As a result, EPCOR has the ability to influence many matters affecting the Company. However, EPCOR has advised the Company that it intends to act only as an investor in and not as a manager of the Company.

Conflicts of interest and disputes may arise between Capital Power and EPCOR relating to a potential misalignment between the companies' corporate objectives and business interests or the companies' past and ongoing relationships. Capital Power may not be able to resolve a potential conflict, and if it does, the resolution may be less favourable to Capital Power than if it were dealing with a party that was not a significant holder of equity of the Company.

Furthermore, EPCOR's significant equity ownership may discourage transactions involving a change of control of the Company, including transactions in which a holder of common shares might otherwise receive a premium for its common shares over the then-current market price.

The interests of other common shareholders are protected by the Board structure which provides EPCOR the right, voting separately as a class, to nominate and elect four directors of the Company. There are currently twelve directors on Capital Power's Board of Directors.

EPCOR has no contractual obligation to retain any exchangeable limited partnership units of CPLP or common shares of the Company. EPCOR has advised the Company that it intends to eventually sell all or a substantial number of the common shares underlying its exchangeable limited partnership units, subject to market conditions, its requirement for capital and other circumstances that may arise in the future. Capital Power is entitled to defer such offerings of common shares requested by EPCOR in certain circumstances for a limited period. Any sale of substantial amounts of common shares in the public market by EPCOR or the Company, or the perception that such sales could occur, could adversely affect prevailing market prices for the common shares and impede the Company's ability to raise capital through the issuance of additional equity securities.

**Conflict of interest risk with CPILP**

As a result of Capital Power's relationship with CPILP, certain conflicts of interest could arise. CPILP's terms of reference for the Board of Directors of CPILP's general partner denote that the Board of Directors shall be composed of not more than eight members, at least four of whom shall be independent directors who are not officers, directors or employees of the Company and are free from any direct or indirect interest, any business or other relationship that could interfere with a director's independence or ability to act in the best interests of CPILP's general partner and CPILP. There are four senior officers of the Company who are members of CPILP's general partner's Board of Directors and are not considered independent in relation to CPILP. The Chairman, who is an executive officer of the Company, has a casting vote in case of a tie vote at any meeting of the Board of Directors of CPILP's general partner. However, any non-arms' length agreements or transactions between CPILP and Capital Power are evaluated solely by a committee of independent directors of CPILP. CPILP's strategic review process may increase the potential for conflicts of interest between CPILP and Capital Power Corporation.

## Future Accounting Changes

**International Financial Reporting Standards**

Canadian reporting issuers are required to report under 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 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 information obtained from the diagnostic phase was used to develop a detailed plan for convergence and implementation. The convergence and implementation work had 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 determined the quantitative impacts to the financial statements, system requirements, accounting policy decisions, and changes to internal controls and business policies.

The following table presents a preliminary reconciliation of the Company's Consolidated Balance Sheet at January 1, 2010 (the date of transition) as previously reported, to the currently anticipated presentation under IFRS. The reconciling amounts are based on analyses and determinations made to date and could change as a result of further analyses or new information.

In determining the impact, the Company made certain policy choices under IFRS. Key policy choices made by the Company are as follows.

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 and the Company plans to apply this election to its Weather Dancer and Miller Creek plants and to certain CPILP assets.
- 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 IFRS, an entity may elect not to apply IFRS 3 retrospectively. The Company plans to elect to not apply IFRS 3 Business Combinations retrospectively and therefore does not plan to restate the transactions related to the Reorganization. However, the Company early adopted the Canadian equivalent to IFRS 3 and applied it to its acquisition of Island Generation in October 2010. See Critical Accounting Estimates and Policies - Business Combinations, Consolidated Financial Statements and Non-Controlling Interests.
- The Company plans to elect to deem the balance for cumulative translation amounts to be nil at the date of transition and to reclassify the previous balance to retained earnings with no impact on the income statement.
- The Company plans to opt for a simplified approach for the measurement of its decommissioning assets included in property, plant and equipment (PP&E) and its decommissioning liabilities (asset retirement obligations) as at the transition date.
- An entity may elect to retrospectively apply the corridor approach under IAS 19, Employee Benefits for the recognition of actuarial gains and losses relating to its employee benefit plans, or to recognize all cumulative gains and losses that were deferred under Canadian GAAP, in opening retained earnings at the date of transition. The Company plans to opt for the latter treatment.

| (unaudited, $millions) | | | Preliminary Transition Adjustments | | | | |
|---|---|---|---|---|---|---|---|
| **Consolidated Statement of Financial Position** January 1, 2010 | | Canadian GAAP as previously reported | IAS 16 and IAS 37 Impact | IAS 36 and IFRS 1 Impact | Other impacts | Reclassi fications | IFRS |
| Cash and cash equivalents | | 52 | - | - | - | - | 52 |
| Accounts receivable[(1)] | | 312 | - | - | - | - | 312 |
| Derivative financial instruments assets | | 146 | - | - | - | - | 146 |
| Inventories | (a) | 63 | 11 | - | - | - | 74 |
| Deferred income tax assets | (b) | 2 | - | - | - | (2) | - |
| Assets held for sale | | 36 | - | - | - | - | 36 |
| Total current assets | | 611 | 11 | - | - | (2) | 620 |
| Other assets | (c) | 120 | - | - | - | (100) | 20 |
| Derivative financial instruments assets | | 155 | - | - | - | - | 155 |
| Finance lease receivables | (c,d) | - | - | - | 66 | 27 | 93 |
| Other financial assets | (c,e) | - | - | - | (3) | 73 | 70 |
| Deferred income tax assets | (b,f) | 61 | - | - | (17) | 2 | 46 |
| Intangible assets | (g) | 712 | - | (10) | - | - | 702 |
| Property, plant and equipment | (d,g,h ,i,l) | 3,237 | 23 | 20 | (54) | 27 | 3,253 |
| Goodwill | (g) | 140 | - | (12) | - | - | 128 |
| Total non-current assets | | 4,425 | 23 | (2) | (8) | 29 | 4,467 |
| Total assets | | 5,036 | 34 | (2) | (8) | 27 | 5,087 |
| Accounts payables | (j) | 339 | - | - | - | (8) | 331 |
| Derivative financial instruments liabilities | (l) | 108 | (1) | - | - | - | 107 |
| Loans and borrowings | | 247 | - | - | - | - | 247 |
| Deferred revenue and other liabilities | | 8 | - | - | - | - | 8 |
| Deferred income tax liabilities | (b) | 21 | - | - | - | (21) | - |
| Provisions | (j,l) | - | (6) | - | - | 8 | 2 |
| Total current liabilities | | 723 | (7) | - | - | (21) | 695 |
| Derivative financial instruments liabilities | (l) | 102 | (7) | - | - | - | 95 |
| Loans and borrowings | | 1,472 | - | - | - | - | 1,472 |
| Deferred revenue and other liabilities | (a,i,j, m,n) | 109 | 22 | - | - | (77) | 54 |
| Deferred income tax liabilities | (b,f) | 95 | - | - | (12) | 21 | 104 |
| Provisions | (j,l) | - | 33 | - | - | 104 | 137 |
| Total non-current liabilities | | 1,778 | 48 | - | (12) | 48 | 1,862 |
| Share capital | | 477 | - | 1 | (1) | - | 477 |
| Retained earnings | | 7 | 13 | (44) | 32 | - | 8 |
| Other reserves (contributed surplus and accumulated other comprehensive income) | | 5 | (9) | 13 | (1) | - | 8 |
| Equity attributable to common shareholders | | 489 | 4 | (30) | 30 | - | 493 |
| Non-controlling interest | | 2,046 | (11) | 28 | (26) | - | 2,037 |
| Total equity | | 2,535 | (7) | (2) | 4 | - | 2,530 |
| Total liabilities and equity | | 5,036 | 34 | (2) | (8) | 27 | 5,087 |

(1) Includes accounts receivable, income taxes recoverable and prepaid expenses.

Explanations of the preliminary transition adjustments in the table above are as follows:

a) Certain spare parts which were previously capitalized, do not meet the criteria for capitalization under IAS 16 - Property, Plant and Equipment. As a result, an additional $11 million was recorded in inventory. The contract between the Genesee mine operator and the Company requires the operating costs of the mine, including depreciation on the operator's share of the mine assets, to be fully funded by the Company, whereas the capital funding is shared by the two parties. As a result, $5 million of amounts previously funded by the operator have been recorded as a non-current liability.

b) IAS 12 – Income Taxes requires all deferred income tax balances to be classified as non-current. Therefore the current deferred income tax assets and liabilities of $2 million and $21 million respectively, were reclassified to non-current income tax assets and liabilities, respectively.

c) IAS 1 - Financial Statements requires financial assets to be presented separate from other assets. Therefore $27 million and $73 million were reclassified from other assets to finance lease receivables and other financial assets, respectively.

d) In accordance with IAS 17 – Leases, the Kingsbridge PPA was determined to be a finance lease. As a result, PP&E was reduced by $54 million, finance lease receivable was increased by $66 million and retained earnings were increased by $12 million.

e) IAS 39 - Financial Instruments requires an asset classified as available for sale to be recorded at fair value with any changes in the fair value recognized in other comprehensive income. Therefore, other financial assets were reduced by $3 million for the difference between the fair value and the previously reported carrying amount for the Company's investment in PERH.

f) To recognize the income tax impact of the IFRS transition adjustments, deferred income tax assets were decreased by $17 million and deferred income tax liabilities were decreased by $12 million.

g) 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 application of undiscounted cash flow analysis has indicated impairment. The adoption of IAS 36 is expected to result in more frequent write downs since the carrying amounts of assets which are supported by undiscounted cash flows may be determined to be impaired when the future cash flows are discounted in accordance with the IFRS requirements. Unlike Canadian GAAP, previous impairment losses may be reversed or reduced under IFRS if the circumstances which led to the impairment change.

   IAS 36 also requires that impairment testing be applied at a cash-generating unit level, which is the smallest identifiable group of assets that generates cash inflows. For Capital Power, some units consist of a single plant and more units are subject to impairment testing under IFRS than under Canadian GAAP. In addition, any goodwill amounts must be allocated and included in the impairment test for each cash-generating unit. Accordingly, there may be more frequent write downs of goodwill under IFRS.

   The Company assessed the fair value of all its facilities and related goodwill and contracts. The Company expects the combined impact of identified impairments and fair value elections taken under IFRS 1 to be a decrease in management contracts of $10 million, an increase in PP&E of $20 million and a decrease in goodwill of $12 million.

h) As a result of applying the componentization requirements of IAS 16 – Property, Plant and Equipment effective July 1, 2009, the net book value of PP&E decreased by $5 million reflecting increased depreciation.

i) International Financial Reporting Interpretations Committee (IFRIC) 18 – Transfers of Assets from Customers requires contributions received for the construction of PP&E that will be used to provide goods or services to be classified as deferred revenue. Therefore $27 million of contributions that were previously reported as a reduction of PP&E were reclassified as an increase in deferred revenue and other liabilities.

j) IAS 1 - Financial Statements requires provisions to be presented as a separate item on the statement of financial position. Therefore, $8 million was reclassified from accounts payable to current provisions and $104 million was reclassified from other non-current liabilities to non-current provisions.

k) The Company plans to elect under IFRS – 1 First Time Adoption of IFRS to adjust the balance of its cumulative translation account to nil at the date of transition. As a result, $4 million was reclassified from the cumulative translation account to retained earnings.

l) IAS 37 – Provisions requires provisions to be measured at the best estimate of the expected expenditure using discount rates appropriate for each. The provision is to be re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Company re-measured its decommissioning liabilities (asset retirement obligations) with respect to the Genesee mine using revised cash flow estimates and re-measured all its decommissioning liabilities using revised discount rates. The re-measurement of the decommissioning liabilities resulted in a decrease of $7 million in the current provision and an increase of $22 million in the non-current provision. The re-measurement of the decommissioning liability also resulted in an increase of $28 million in the associated PP&E.

Under IFRS, amounts provided for the unavoidable costs of the Company's Alberta retail and commercial natural gas contracts are recognized as provisions. Accordingly, the Company reclassified $1 million from current derivative financial instrument liabilities to current provisions and $7 million from non-current derivative financial instrument liabilities to non-current provisions. The non-current provision was also increased by $4 million for the impact of the measurement requirements of IAS 17 on the provision for these contracts.

m) Under Canadian GAAP, the Joffre joint venture's overhaul costs for the Joffre cogeneration facility were expensed and the joint venture's recovery of overhaul costs from one of the joint venture partners, was recognized as revenue in the period that the cost was incurred. Under the requirements of IAS 16, the overhaul costs are capitalized as a component of PP&E and recoveries are recognized in income over the period that the corresponding asset is depreciated. Therefore, deferred revenues increased $3 million on transition to IFRS for recoveries received by the joint venture for costs that had been expensed under Canadian GAAP and reclassified as PP&E under IFRS.

n) The contract between the Genesee mine operator and Capital Power requires the operating costs of the mine, including depreciation on the operator's share of the mine assets, to be fully funded by Capital Power, whereas the capital funding is shared. Certain costs that were previously capitalized would have been expensed under the requirements of IAS 16 and fully funded by Capital Power. As a result, other non-current liabilities increased by $19 million, $5 million of which relates to the inventory adjustment in (a) above, to reflect the amount owing to the Genesee mine operator for costs previously paid by the operator.

The Company expects the adjustments above to have the following impact on earnings in future periods.

a) The change in accounting classification of the Kingsbridge PPA from an executory contract to a finance lease will result in decreased revenues and decreased depreciation expense.

b) The change to capitalize inspections and major overhauls and to amortize them over the estimated period between overhauls will result in a decrease in staff costs and raw materials and an increase in depreciation expense.

c) The componentization of PP&E at a more detailed level and the increase in decommissioning assets for changes in the associated discount rates will result in an increase in depreciation expense.

d) Changes to the calculation of capitalized borrowing costs will result in a decrease in finance expense.

e) Revenue and depreciation will increase to reflect the requirement under IFRIC 18 to present the amortization of contributions for PP&E as revenue rather than as a reduction of depreciation.

f) Depreciation expense will decrease and finance expense will increase to reflect the presentation of the accretion of asset retirement obligations as finance expense rather than depreciation expense, in accordance with the requirements of IFRIC 1 – Changes in Existing Decommissioning, Restoration and Similar Liabilities.

*Financial Statements*

There are a number of international standards which relate to financial statement presentation. The development of the financial statement presentation evolved throughout the project as the impacts of implementing the various standards were quantified. The Company identified those areas requiring additional disclosure and developed processes to capture the additional information. Draft financial statements for the six months ended June 30, 2010 were prepared in accordance with IFRS, with an opening statement of financial position as at January 1, 2010. These preliminary financial statements were presented to the Audit Committee in November 2010.

*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 and implemented parallel general ledgers and fixed asset systems to allow both IFRS and Canadian GAAP information to be captured in 2010. The processes and internal controls related to the capture and reporting of IFRS information are similar to those used for Canadian GAAP.

*Policies and Internal Controls*

In the determination of the financial statement adjustments, requirements for changes to the Company's policies and internal controls were identified and documented. The changes were not significant.

The impact of IFRS on certain material agreements, such as debt, shareholder and compensation agreements, was assessed and the Company has not identified any provisions within the agreements which would be negatively impacted by the differences between IFRS and Canadian GAAP.

In the fourth quarter of 2010, the Company's investor relations department worked with the IFRS team to prepare information for the investor analysts.

*Training*

The Company recognized that training at all levels of the Company is essential to a successful conversion and integration. Accounting staff attended four general training sessions as well as working sessions focussed on specific topics. Training sessions for the Audit Committee occurred in March 2010 and November 2010 and the Audit Committee received 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.

**Business combinations, consolidated financial statements and non-controlling interests**

In January 2009, the Canadian Institute of Chartered Accountants (CICA) issued Handbook Section 1582 – Business Combinations which replaces Handbook Section 1581 – Business Combinations and provides the Canadian equivalent to IFRS 3 – Business Combinations. In January 2009, the CICA also issued Handbook Sections 1601 – Consolidated Financial Statements and 1602 – Non-controlling Interests which replace Handbook Section 1600 – Consolidated Financial Statements. Section 1602 is the equivalent to the corresponding provisions of IAS 27 – Consolidated and Separate Financial Statements.

Effective January 1, 2010, the Company elected in accordance with the transitional provisions to early adopt these new accounting standards to minimize the impact of adopting IFRS in 2011. The Company would otherwise have been required to adopt the IFRS equivalents of these new accounting standards effective January 1, 2011.

The impacts of adopting these standards, as they pertain to the Island Generation acquisition and prospective business combinations, include:

- business combinations are measured at the fair value of the identifiable assets acquired and liabilities assumed, including fair values attributable to non-controlling interests;
- contingent consideration is included in the consideration transferred in a business combination that is measured at fair value;
- acquisition-related costs are expensed as incurred; and
- changes in non-controlling interests subsequent to the Company's acquisition of control, which do not result in the Company's loss of control, are accounted for as equity transactions.

The Company's consolidated financial statements reflect the following changes to the presentation and disclosure of non-controlling interests for the current and comparative periods:

- non-controlling interests are presented as a separate component of shareholders' equity in the consolidated balance sheets and statements of changes in shareholders' equity; and

- net income and other comprehensive income are attributed to the Company's common shareholders and non-controlling interests on the consolidated statements of income and other comprehensive income.

As a result of the application of Section 1582, the Company recognized $2 million of costs relating to the Island Generation acquisition and integration in indirect administration expenses for the year ended December 31, 2010.

**Revenue recognition under PPAs**

Revenues from certain of the Company's power generation plants are recognized upon delivery of output or upon availability for delivery as prescribed by contractual arrangements. These contractual arrangements are also commonly referred to as PPAs. Revenues from certain PPAs are recognized at the lower of (1) the MWhs made available during the period multiplied by the billable contract price per MWh, and (2) an amount determined by the MWhs made available during the period multiplied by the average price per MWh over the term of the contract. Any excess of the contract price for the period over the average price is recorded as deferred revenue.

**Financial instruments**

The Company is required to estimate the fair value of certain assets and obligations for determining the valuation of certain financial instruments. The financial instrument fair value measurements that are recognized in the consolidated balance sheet are categorized into three levels of a hierarchy based on the reliability of the inputs used to estimate the fair value, as described below. The fair value measurement for a financial instrument is included in the lowest level of those levels attributable to its significant inputs.

Level 1 – Fair value is based on unadjusted quoted prices in active markets for identical instruments.

Level 2 – Fair value is based on other than unadjusted quoted prices included in level 1, which are either directly or indirectly observable. This includes models using inputs that are quoted prices in active markets for similar instruments, quoted prices for identical or similar instruments in markets that are not active, and other observable inputs that are principally derived from or corroborated by observable market data for substantially the full term of the instrument. The majority of the Company's fair value estimates for financial instruments are based on valuation models, primarily the discounted cash flow model, that directly or indirectly use observable market inputs. The observable market inputs include commodity prices, interest rates, foreign exchange rates, and credit spreads.

Level 3 – Fair value is based on models using significant inputs that are not based on observable market data. The Company uses models with unobservable inputs to estimate the fair value of its financial instruments that are not actively traded. For example, the fair values of certain credit derivative and option products are estimated using models with unobservable inputs such as default probabilities and volatilities.

The Company's equity investments that do not have quoted market prices in active markets are classified as available for sale and are recorded at their cost amount on the balance sheet. Management assesses these financial assets for impairment by estimating their fair values based on discounted expected cash flow analyses. Such analyses consider factors such as the financial condition and future prospects of the issuer of the instrument.

**Long-lived assets**

Depreciation and amortization allocate the cost of assets over their estimated useful lives on a systematic and rational basis. Depreciation and amortization also include amounts for future decommissioning costs and asset retirement obligation accretion expenses. Estimating the appropriate useful lives of assets requires significant judgement and is generally based on estimates of the life characteristics of common assets.

The Company reviews the valuation of long-lived assets subject to amortization when events or changes in circumstances may indicate or cause a long-lived asset's carrying amount to exceed the total undiscounted future cash flows expected from the asset's use and eventual disposition. An impairment loss, if any, would be recorded as the excess of the carrying amount of the asset over its fair value.

For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. Goodwill arising on business combinations is tested for impairment annually or more frequently if events and circumstances indicate that a possible impairment may exist. To test for impairment, the fair value of the reporting unit to which the goodwill relates is compared with the carrying value, including goodwill, of the reporting unit. If the carrying value of the reporting unit exceeds its fair value, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the impairment loss, if any.

Estimates of fair value for goodwill and other asset impairments, and purchase price allocations are primarily based on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate. The cash flow estimates will vary with the circumstances of the particular assets or reporting unit and will be based on, among other things, the lives of the assets, contract prices, estimated future prices, revenues and expenses, including inflation, and required capital expenditures.

**Asset retirement obligations and other provisions**

The fair values of asset retirement obligations are estimated using the total undiscounted amount of the estimated future cash flows required to settle the obligations and applying the appropriate credit-adjusted risk-free discount rate. In this process assumptions are made regarding the useful lives of the assets and the legal restoration obligations. The range for the estimates of fair value for the purposes of determining an asset retirement obligation varies by asset.

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

**Income taxes**

The Company follows the asset and liability method of accounting for income taxes. Income tax expense is based on the earnings of the period, the jurisdiction in which the income is earned, and any differences between the calculations of pre-tax income under Canadian GAAP and income tax law. These factors impact the income tax rates and amounts of income tax expense.

Current income taxes are recognized for the estimated income taxes payable or recoverable for the period. Estimates of future income taxes resulting from temporary differences between the carrying values of assets and liabilities in the financial statements and their tax values are recognized as future income tax assets and liabilities. The Company applies estimated future income tax rates to the temporary differences to determine the amount of income tax expense and change in future income tax assets and liabilities for the period. The future income tax rates are estimated based on the rates that are anticipated for the future periods in which the temporary difference are expected to reverse. When a government announces a change in future income tax rates, the carrying amounts of the Company's future income tax assets or liabilities are adjusted and reflected in income tax expense or other comprehensive income as appropriate. In the year ended December 31, 2010, changes in income tax laws and rates did not impact income tax expense.

Future income tax assets are assessed to determine the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered likely, a valuation allowance is recorded and charged against income in the period that the allowance is created or revised.

Estimates of the provision for current income taxes, future income tax assets and liabilities and any related valuation allowance might vary from actual amounts incurred. Income taxes will vary with taxable income and, under certain conditions, with fair values of assets and liabilities. The effective income tax rate can change depending on the mix of earnings from different jurisdictions, the magnitude of tax amounts and income attributable to non-controlling interests, and the amount of deductions that do not fluctuate with earnings. The effective tax rate on earnings before income taxes for the year ended December 31, 2010 was 5.6% and was lower than the statutory income tax rate primarily due to $33 million of income taxes related to taxable income attributable to non-controlling interests.

**Leases or arrangements containing a lease**

Leases or other arrangements entered into for use of property, plant and equipment are classified as either capital or operating leases. Leases or other arrangements that transfer substantially all of the benefits and risks of ownership of property to the Company are classified as capital leases. Equipment acquired under capital leases is depreciated over the term of the lease. Rental payments under operating leases are expensed as incurred.

Certain power generation plants operate under PPAs that convey the rights to use the related property, plant and equipment to the holder of the agreements. Consequently, these power generation plants are accounted for as assets under operating leases.

**Foreign currency translation**

CPILP has operations in the U.S. with a functional currency of U.S. dollars. Accordingly, these operations are translated using the current rate method whereby assets and liabilities are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Revenues and expenses are translated at rates in effect at the time of the transactions. The resulting foreign exchange gains and losses are accumulated as a component of accumulated other comprehensive income.

**Consolidation of CPILP and CPLP**

While the Company indirectly owns only 29.6% (30.5% at December 31, 2009) of the outstanding units of CPILP and an approximate 39.5% interest in CPLP, it controls both partnerships under Canadian GAAP. Accordingly, CPILP and CPLP are consolidated in the financial statements of the Company.

## 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 December 31, 2010 were as follows:

| | Carrying amount | | Fair value |
|---|---|---|---|
| (unaudited, $ millions) | Loans and receivables | Other financial liabilities | |
| Other assets | $ 77 | $ - | $ 77 |
| Long-term debt (including current portion) | $ - | $ 1,869 | $ 1,920 |

**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 except 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 held at December 31, 2010 and used for risk management purposes were measured at fair value and consisted of the following:

| (unaudited, $ millions) | Energy cash flow hedges | Energy non-hedges | Foreign exchange non-hedges | Interest rate non-hedges | Total |
|---|---|---|---|---|---|
| Total derivative instruments net assets (liabilities) | $ (57) | $ 37 | $ 33 | $ (6) | $ 7 |

**Energy derivatives designated as accounting hedges**

At December 31, 2010, the net fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of $57 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.

On July 31, 2009, CPILP applied hedge accounting to certain of its natural gas purchase contracts. Unrealized losses net of income taxes on these derivative instruments of $45 million for the effective portion of the cash flow hedges were recognized in other comprehensive income in 2010. Prior to the application of the hedge, the unrealized changes in the fair value of these contracts were recognized in net income.

**Derivatives not designated as accounting hedges**

At December 31, 2010, the net fair value of energy derivative instruments not designated as hedges for accounting was a net asset of $37 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 a net short position for the portfolio combined with lower forward Alberta electricity prices, relative to the derivative contract prices.

At December 31, 2010, the fair value of the Company's forward foreign currency contracts was a net derivative instrument asset of $33 million. The net asset was primarily 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. As at December 31, 2010, $349 million (US$309 million) or approximately 96% of expected future net U.S. dollar cash flows from CPILP's U.S. plants for 2011 to 2016 were economically hedged at a weighted average exchange rate of $1.13 to US$1.00. As at December 31, 2010, $8 million (US$7 million) or approximately 97% of expected future net U.S. dollar cash flows for capital expenditure commitments for 2011 were economically hedged at a weighted average exchange rate of $1.07 to US$1.00. 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.

At December 31, 2010 the fair value of the Company's two $100 million forward bond sale contracts was a net derivative instrument liability of $6 million. These contracts were entered into the second quarter of 2010 and the liability at December 31, 2010 was due to the decreases in future interest rates.

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. 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.

For example, the Company usually has more physical supply of power in Alberta from its generating stations and power purchased under PPAs than the Company has contracted to physically sell. The Company utilizes financial sales contracts to reduce its exposure to changes in the price of power in Alberta. Economically, the Company benefits from higher Alberta power prices due to the net long position held since the Company's expected physical supply is in excess of the Company's physical and financial sales contracts. However, financial sales contracts that are not hedged for accounting purposes are recorded at fair value at each balance sheet date and the offsetting anticipated future physical supply or economically hedged item is not. Accordingly, an increase in forward Alberta power prices can result in fair value losses for accounting purposes whereas on an economic basis, these losses are offset by unrecognized gains on the physical supply. The economic gains will be recognized in later periods when the power is produced and sold. The opposite is true for forward price decreases in Alberta power.

**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 December 31, 2010, losses net of income taxes on derivative instruments designated as cash flow hedges, of $36 million were recorded in other comprehensive income for the effective portion of cash flow hedges. Realized losses, net of income taxes, for the period ended December 31, 2010 of $8 million were reclassified to energy purchases and revenues as appropriate. For the period ended December 31, 2010, the change in the fair value of the ineffective portion of hedging derivatives recognized in the income statement, before non-controlling interests, was $2 million. Net gains of $9 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.

## Internal Control over Financial Reporting

As of December 31, 2010, management conducted an evaluation of the design and effectiveness of the Company's disclosure controls and procedures to provide reasonable assurance that material information relating to the Company is made known to management by others, particularly during the period in which the Company's annual filings are being prepared, and that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The evaluation took into consideration the Company's Disclosure Policy and internal sub-certification process, and the functioning of its Disclosure Committee. In addition, the evaluation covered the Company's processes, systems and capabilities relating to public disclosures and the identification and communication of material information. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are appropriately designed and effective.

Also as of December 31, 2010, management conducted an evaluation of the design and effectiveness of internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's internal controls over financial reporting are appropriately designed and effective.

These evaluations were conducted in accordance with the standards of the Committee of Sponsoring Organizations, a recognized control model, and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

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

## Forward-looking Information

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

Forward-looking information in this MD&A includes, among other things, information relating to: (i) expectations regarding the review of strategic alternatives for CPILP, its potential outcome, and the intention of Capital Power to support the review of strategic alternatives but not participate as a prospective buyer if a sale were to occur; (ii) expectations regarding the timing of the CPILP strategic review process and that during the review process CPILP will continue its business as usual, provide the same amount of monthly distributions to its unitholders and maintain the same proposition it offers today; (iii) Capital Power's intention to continue managing CPILP assets; (iv) expectations for the Company's and CPILP's sources of capital and use, adequacy and availability of committed bank credit facilities and potential future borrowings; (v) the Company's and CPILP's cash requirements for 2011, including interest and principal repayments, capital expenditures, distributions and dividends; (vi) expected funding of the Quality Wind and Port Dover & Nanticoke wind projects during construction and once completed while maintaining overall leverage in the range of 40% - 50%; (vii) expected contracted price for power under the OPA's FIT program for Port Dover & Nanticoke Wind project; (viii) expectations regarding the impact of a full year of operating activities from Island Generation on operating margin and its impact on earnings and cash flow; (ix) expectations regarding amount and timing of future distributions; (x) expectations regarding the timing and amount for the recovery and settlement of the business interruption claim for the outage of Clover Bar Energy Centre Unit 2; (xi) expectations regarding timing of spending on Keephills 3; (xii) expectations regarding the impact of Keephills 3 coming on-line on cash flow and earnings per share; (xiii) expected total capital project costs and expenditures as well as expected project completion dates and expected payments under contractual obligations; (xiv) expectations about earnings performance and funds from operations in the first quarter of 2011, full year earnings in 2011 and future income; (xv) expected impacts of transition to IFRS, including preliminary transition adjustments and their impact on earnings in future periods; (xvi) expected improvement in and reduction of future plants' environment emission levels and ability to capture future emissions; (xvii) expectations regarding proposed new environmental regulations and the impact of current and new emissions regulation on future environmental regulation compliance costs; (xviii) expectations regarding the carbon capture storage FEED study, timing of completion, and expecting timing of decision to proceed with the project; (xix) expectations regarding the timing of new environmental regulations being brought into force; (xx) expectations regarding normalized earnings per share, cash provided by operating activities and funds from operations in 2011; (xxi) expectations regarding Alberta power prices for 2011 and 2012; (xxii) expectations regarding the impact of power prices in 2011 on earnings and funds from operations and on the Company's unhedged position, profitability from peaking facilities, and availability incentive revenues; (xxiii) expectations regarding plant availability targets, plant maintenance capital expenditures and Genesee mine extension, and total shareholder return in 2011; (xxiv) expectations regarding the impact of Clover Bar Energy Centre Unit 3 being offline on plant availability and on financial results; (xxv) expected timing of return of service date of Clover Bar Energy Centre Unit 3 and expected timing of Unit 2 outage; (xxvi) expectations regarding the timing and impact on earnings of the scheduled maintenance outage at Genesee 1 in 2011; (xxvii) expectations regarding the Kingsbridge II project and other proposed projects in the Bruce-Huron area and related possibilities to be awarded a FIT contract and anticipated timing of award of contract; (xxviii) expectations regarding the development of the proposed Halkirk I project as well as scheduled timing of project completion; (xxix) expectations regarding the Company's strategy, including (a) the Company's expectation to maintain a stable dividend and an investment-grade credit rating supported by contracted cash flows, (b) the Company's expectation to commit at least $1.5 billion of new development or acquisitions in 2011, (c) the Company's expectation of continuing to sell forward a significant portion of its generation output and capacity, and maintain a target for contracted plants to provide approximately 50% of the Company's operating margin; (xxx) expectations in respect of the new PPAs at CPILP's North Carolina plants; (xxxi) the Company's belief that the outcome of any claims or potential claims of which it is aware will not have a material adverse effect on Capital Power's financial conditions and results of operations; (xxxii) expectations that the Tiverton and Rumford acquisition will exceed the targeted rate of return Capital Power seeks from merchant assets and expectations regarding accretion to earnings and impact on earnings per share; (xxxiii) expectations regarding the purchase price, timing of closing, and financing of the Tiverton, Rumford and Bridgeport acquisitions; (xxxiv) expectations regarding the ability to attain the goal of 10,000 MW of assets by 2020 on a consistently accretive basis; (xxxv) expectations that the Tiverton, Rumford and Bridgeport power plants will provide Capital Power with the foundation of a networked hub in the U.S. Northeast; (xxxvi) expectations that the Tiverton, Rumford and Bridgeport power plants will contribute to a balanced portfolio of contracted and merchant assets; (xxxvii) expectations regarding the earnings from the Tiverton and Rumford plants as a result of the expectation that power prices will recover in the New England market; (xxxviii) expected timing of when CPILP will make material cash income tax payments; (xxxix) expectations in respect of new PPAs at the North Carolina facilities and expectations with respect to CPILP's long-term outlook for the North Carolina plants; (xxxx) expectations regarding and impact of TransAlta's intent to terminate the Sundance 1 and 2 PPAs following the damage to both facilities; (xxxxi) expectations regarding mitigating risks through the commodity risk program; and (xxxxii) expectations that Bridgeport can maximize energy and ancillary services revenue through operational flexibility.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements include, but are not limited to: (i) the operation of the Company's facilities; (ii) power plant availability and dispatch, including Sundance which is subject to an acquired PPA; (iii) the Company's financial position and credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) weather; (vii) availability and cost of labour and management resources; (viii) performance of contractors and suppliers; (ix) availability and cost of financing; (x) foreign exchange rates; (xi) management's analysis of applicable tax legislation; (xii) currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; (xviii) ability to obtain necessary regulatory approvals for development projects; (xix) the Company's assessment of capital markets and ability to complete future share and debt offerings; (xx) locations of projects and the areas of which they will be developed, including the availability and use of certain optioned lands; (xxi) costs of construction and development; (xxii) current risk management strategies including hedges will be in place; and (xxiii) ability to manage the transition to IFRS.

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

This MD&A includes the following updates to previously disclosed forward-looking statements: (i) expectations regarding capital expenditures in 2011 have been revised to reflect a change in the timing of spending on the Keephills 3 and Quality Wind projects; and (ii) the expected timing of the completion of the final testing and the building of access roads at CPILP's Southport plant has been revised from the fourth quarter of 2010 to 2011.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. Forward-looking statements are provided for the purpose of providing information about management's current expectations, and plans relating to the future. Readers are cautioned that such information may not be appropriate for other purposes. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

## Quarterly Information

Quarterly revenues, net income and funds provided by operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, planned and unplanned plant outages, as well as items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's derivative power, natural gas, foreign exchange and forward bond sale contracts, and natural gas held for trading.

**Financial highlights**

| (unaudited, $millions except earnings (loss) per share) | Three months ended | | | | | |
|---|---|---|---|---|---|---|
| | Dec 31, 2010 | Sept 30, 2010 | June 30, 2010 | March 31, 2010 | Dec 31, 2009 | Sept 30, 2009 |
| Revenues[3] | 440 | 508 | 313 | 499 | 497 | 511 |
| Gross margin[1] | 203 | 229 | 120 | 216 | 216 | 218 |
| Operating margin[1] | 122 | 176 | 55 | 167 | 154 | 169 |
| Net income (loss) | 24 | 47 | (38) | 104 | 39 | 80 |
| Net income attributable to common shareholders | (1) | 7 | (8) | 13 | 7 | 14 |
| Earnings (loss) per share | $ (0.04) | $ 0.32 | $ (0.37) | $ 0.60 | $ 0.33 | $ 0.64 |
| Fully diluted earnings (loss) per share[2] | $ (0.04) | $ 0.31 | $ (0.37) | $ 0.60 | $ 0.30 | $ 0.59 |
| Funds from operations[1][4] | 82 | 112 | 58 | 102 | 75 | 96 |
| Normalized earnings per share[1] | $ 0.26 | $ 0.55 | $ 0.05 | $ 0.55 | $ 0.18 | $ 0.42 |
| Capital expenditures | 52 | 74 | 133 | 78 | 122 | 108 |
| Long-term debt including current portion | 1,869 | 1,773 | 1,808 | 1,634 | 1,719 | 1,771 |
| Total assets | 5,217 | 5,005 | 5,015 | 4,952 | 5,036 | 4,918 |

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

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

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

(4) Funds from operations for previous quarters have been reclassified to conform to the presentation adopted in the fourth quarter of 2010.

**Generation volume and plant availability information**

| (unaudited, GWh)<br><br>**Electricity generation**[1] | Year ended Dec 31, 2010 | Three months ended Dec 31, 2010 | Sept 30, 2010 | June 30, 2010 | March 31, 2010 | Six months ended Dec 31, 2009 | Three months ended Dec 31, 2009 | Sept 30, 2009 |
|---|---|---|---|---|---|---|---|---|
| Alberta commercial plants | | | | | | | | |
| Genesee 3 | 1,662 | 272 | 475 | 432 | 483 | 954 | 484 | 470 |
| Joffre | 283 | 82 | 67 | 93 | 41 | 162 | 73 | 89 |
| Clover Bar Energy Centre 1, 2 and 3[2] | 361 | 179 | 37 | 102 | 43 | 25 | 9 | 16 |
| Taylor Coulee Chute | 11 | 1 | 7 | 3 | - | 14 | 2 | 12 |
| Clover Bar Landfill Gas | 38 | 9 | 9 | 10 | 10 | 19 | 10 | 9 |
| Weather Dancer | - | - | - | - | - | - | - | - |
| | 2,355 | 543 | 595 | 640 | 577 | 1,174 | 578 | 596 |
| Alberta contracted plants | | | | | | | | |
| Genesee 1 | 3,288 | 854 | 841 | 780 | 813 | 1,455 | 618 | 837 |
| Genesee 2 | 3,046 | 826 | 824 | 571 | 825 | 1,618 | 817 | 801 |
| | 6,334 | 1,680 | 1,665 | 1,351 | 1,638 | 3,073 | 1,435 | 1,638 |
| Ontario and British Columbia contracted plants | | | | | | | | |
| Kingsbridge 1 | 105 | 39 | 18 | 22 | 26 | 46 | 32 | 14 |
| Miller Creek | 95 | 7 | 46 | 35 | 7 | 61 | 14 | 47 |
| Brown Lake | 43 | 14 | 5 | 11 | 13 | 26 | 15 | 11 |
| Island Generation | 273 | 273 | - | - | - | - | - | - |
| | 516 | 333 | 69 | 68 | 46 | 133 | 61 | 72 |
| **Total plants excluding CPILP plants** | **9,205** | **2,556** | **2,329** | **2,059** | **2,261** | **4,380** | **2,074** | **2,306** |
| CPILP plants | 5,013 | 1,311 | 1,306 | 1,128 | 1,268 | 2,635 | 1,407 | 1,228 |
| **Total plants** | **14,218** | **3,867** | **3,635** | **3,187** | **3,529** | **7,015** | **3,481** | **3,534** |

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

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

| (unaudited) Generation plant availability[(1)] | Year Ended Dec 31, 2010 | Three months ended Dec 31, 2010 | Sept 30, 2010 | June 30, 2010 | March 31, 2010 | Six months ended Dec 31, 2009 | Three months ended Dec 31, 2009 | Sept 30, 2009 |
|---|---|---|---|---|---|---|---|---|
| Alberta commercial plants | | | | | | | | |
| Genesee 3 | 88% | 56% | 99% | 96% | 100% | 98% | 99% | 97% |
| Joffre | 95% | 99% | 98% | 84% | 100% | 95% | 94% | 96% |
| Clover Bar Energy Centre 1, 2 and 3[(2)] | 71% | 95% | 63% | 52% | 72% | 97% | 98% | 96% |
| Taylor Coulee Chute | 97% | 100% | 100% | 90% | 98% | 83% | 66% | 100% |
| Clover Bar Landfill Gas | 93% | 88% | 92% | 96% | 96% | 92% | 94% | 90% |
| Weather Dancer | 20% | 0% | 0% | 0% | 83% | 28% | 0% | 55% |
| | 84% | 83% | 86% | 76% | 98% | 97% | 97% | 96% |
| Alberta contracted plants | | | | | | | | |
| Genesee 1 | 100% | 100% | 100% | 100% | 99% | 87% | 74% | 100% |
| Genesee 2 | 92% | 97% | 97% | 75% | 99% | 96% | 97% | 95% |
| | 96% | 98% | 99% | 87% | 99% | 92% | 85% | 97% |
| Ontario and British Columbia contracted plants | | | | | | | | |
| Kingsbridge 1 | 99% | 100% | 99% | 100% | 99% | 99% | 100% | 99% |
| Miller Creek | 60% | 12% | 96% | 96% | 37% | 92% | 97% | 88% |
| Brown Lake | 97% | 99% | 93% | 99% | 97% | 98% | 99% | 97% |
| Island Generation | 99% | 99% | - | - | - | - | - | - |
| | 90% | 91% | 97% | 98% | 71% | 97% | 99% | 94% |
| **Average excluding CPILP plants[(3)]** | **90%** | **91%** | **93%** | **83%** | **97%** | **94%** | **92%** | **97%** |
| CPILP plants[(3)] | 95% | 97% | 97% | 90% | 95% | 93% | 92% | 93% |
| **Average all plants[(3)]** | **92%** | **95%** | **95%** | **86%** | **96%** | **94%** | **92%** | **95%** |

(1) Plant availability represents the percentage of time in the period that the plant was available to generate power, regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

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

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

The Company's target for plant availability excluding CPILP plants for 2010 was 94%. In the fourth quarter of 2010, 91% was achieved for this performance measure, reflecting the scheduled maintenance outages at Genesee 3 and Miller Creek Unit 1 for 42 days and 89 days, respectively. Clover Bar Energy Centre Unit 2 was offline from March 8, 2010 through to September 22, 2010 for mechanical issues. Performance in the second quarter of 2010 also reflected a 21-day outage at Genesee 2 for scheduled maintenance and a 15-day outage at Clover Bar Energy Centre Unit 3 for an equipment issue. All three Genesee units were impacted by curtailments to facilitate transmission upgrades in the second quarter of 2010. There was a scheduled outage at Genesee 1 during the fourth quarter of 2009 and no other major outages in the six months ended December 31, 2009.

**Results by plant category**

| (unaudited, $ millions) | Year ended Dec 31, 2010 | Three months ended Dec 31, 2010 | Three months ended Sept 30, 2010 | Three months ended June 30, 2010 | Three months ended March 31, 2010 | Six months ended Dec 31, 2009 | Three months ended Dec 31, 2009 | Three months ended Sept 30, 2009[2] |
|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | |
| Alberta commercial plants and portfolio optimization | $ 918 | $ 236 | $ 250 | $ 197 | $ 235 | $ 486 | $ 248 | $ 238 |
| Alberta contracted plants | 272 | 74 | 71 | 55 | 72 | 131 | 61 | 70 |
| Ontario/British Columbia contracted plants | 23 | 12 | 4 | 4 | 3 | 8 | 4 | 4 |
| CPILP plants | 524 | 139 | 130 | 116 | 139 | 253 | 130 | 123 |
| Other portfolio activities | 111 | 28 | 15 | 25 | 43 | 63 | 40 | 23 |
| Inter-plant category transaction eliminations | (41) | (11) | (10) | (10) | (10) | (19) | (9) | (10) |
| | 1,807 | 478 | 460 | 387 | 482 | 922 | 474 | 448 |
| Unrealized fair value changes in derivative instruments and natural gas inventory held for trading | | | | | | | | |
| - CPLP | (55) | (49) | 37 | (55) | 12 | 45 | 15 | 30 |
| - CPILP | 8 | 11 | 11 | (19) | 5 | 41 | 8 | 33 |
| | (47) | (38) | 48 | (74) | 17 | 86 | 23 | 63 |
| | **$ 1,760** | **$ 440** | **$ 508** | **$ 313** | **$ 499** | **$ 1,008** | **$ 497** | **$ 511** |
| **Gross margin[1]** | | | | | | | | |
| Alberta commercial plants and portfolio optimization | 255 | $ 58 | $ 72 | $ 60 | $ 65 | $ 103 | $ 53 | $ 50 |
| Alberta contracted plants | 216 | 57 | 57 | 43 | 59 | 106 | 48 | 58 |
| Ontario/British Columbia contracted plants | 23 | 12 | 4 | 4 | 3 | 8 | 4 | 4 |
| CPILP plants | 305 | 84 | 76 | 68 | 77 | 151 | 74 | 77 |
| Other portfolio activities | 36 | 4 | 9 | 8 | 15 | 20 | 12 | 8 |
| Inter-plant category transaction eliminations | (37) | (10) | (9) | (9) | (9) | (17) | (9) | (8) |
| | 798 | 205 | 209 | 174 | 210 | 371 | 182 | 189 |
| Unrealized fair value changes in derivative instruments and natural gas inventory held for trading | | | | | | | | |
| - CPLP | (26) | (13) | 14 | (36) | 9 | 42 | 26 | 16 |
| - CPILP | (4) | 11 | 6 | (18) | (3) | 21 | 8 | 13 |
| | (30) | (2) | 20 | (54) | 6 | 63 | 34 | 29 |
| | **$ 768** | **$ 203** | **$ 229** | **$ 120** | **$ 216** | **$ 434** | **$ 216** | **$ 218** |
| **Operating margin[1]** | | | | | | | | |
| Alberta commercial plants and portfolio optimization | $ 196 | $ 35 | $ 59 | $ 47 | $ 55 | $ 80 | $ 39 | $ 41 |
| Alberta contracted plants | 156 | 43 | 48 | 19 | 46 | 74 | 27 | 47 |
| Ontario/British Columbia contracted plants | 16 | 9 | 3 | 2 | 2 | 6 | 3 | 3 |
| CPILP plants | 183 | 41 | 48 | 41 | 53 | 95 | 47 | 48 |
| Other portfolio activities | 3 | (3) | 1 | - | 5 | 6 | 4 | 2 |
| Inter-plant category transaction eliminations | (4) | (1) | (3) | - | - | (1) | - | (1) |
| | 550 | 124 | 156 | 109 | 161 | 260 | 120 | 140 |
| Unrealized fair value changes in derivative instruments and natural gas inventory held for trading | | | | | | | | |
| - CPLP | (26) | (13) | 14 | (36) | 9 | 42 | 26 | 16 |
| - CPILP | (4) | 11 | 6 | (18) | (3) | 21 | 8 | 13 |
| | (30) | (2) | 20 | (54) | 6 | 63 | 34 | 29 |
| | **$ 520** | **$ 122** | **$ 176** | **$ 55** | **$ 167** | **$ 323** | **$ 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.

| (unaudited, $/MWh) Alberta power prices | Year ended Dec 31, 2010 | Three months ended Dec 31, 2010 | Sept 30, 2010 | June 30, 2010 | Mar 31, 2010 | Six months ended Dec 31, 2009 | Three months ended Dec 31, 2009 | Sept 30, 2009 |
|---|---|---|---|---|---|---|---|---|
| Average Alberta power spot price | $50.88 | $45.94 | $35.77 | $81.15 | $40.78 | $47.88 | $46.27 | $49.49 |
| Capital Power's Alberta portfolio's average realized power price | 66 | 64 | 66 | 66 | 67 | 56 | 57 | 54 |

**Factors impacting the 2010 fourth quarter results**

The realized price for the Alberta commercial plants and portfolio optimization in the fourth quarter of 2010 was $64/MWh which was $18/MWh higher than the average Alberta power price for the period. Increases in Alberta power spot prices and volatility in those prices provided opportunities to dispatch the Alberta commercial peaking and mid-merit plants and thereby contribute to revenues and operating margin. This increased generation was partly offset by reduced generation from Genesee 3 as a result of a 42-day scheduled maintenance outage. Maintenance expenses for the outage were $8 million. In the fourth quarter of 2010, revenues from the Company's RRT business were impacted by decreased pricing but this 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.

The operating margin for the Ontario and British Columbia contracted plants benefited from contributions from the Island Generation facility following its acquisition on October 19, 2010.

Revenues for the CPILP plants in the fourth quarter reflected the completion of the Oxnard turbine upgrade which was considered to be sold for accounting purposes, as well as higher dispatch of the North Carolina facilities. The additional revenues were substantially offset by the cost of the turbine upgrade, and increased fuel and operating costs at the North Carolina facilities.

The fair value of CPLP's derivative instruments decreased in the fourth quarter primarily due to the impact of increased Alberta forward power prices on the portfolio position. The increase in the fair value of CPILP's derivative instruments primarily reflected the impact of strengthening future prices for the Canadian dollar relative to the U.S. dollar on foreign exchange contracts.

In December 2010, a subsidiary of EPCOR exchanged 9,209,000 of its exchangeable limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis reducing EPCOR's ownership interest in CPLP to approximately 60.5% from its initial interest of 72.2%. Net income from CPLP for the year ended December 31, 2010 was attributed between the partners on the same basis as distributions were paid or payable to the partners for the year, which was 69.31% to the EPCOR subsidiary and 30.69% to the Capital Power subsidiary. As a result of this transaction, the Capital Power subsidiary's increased interest in CPLP's income for the first three quarters of 2010 was approximately $3 million which was recognized in the fourth quarter of 2010.

**Factors impacting results for the previous quarters**

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

The realized price for the Alberta commercial plants and portfolio optimization in the third quarter of 2010 was $66/MWh which was $30/MWh higher than the average Alberta power price for the period. The expected recovery of $8 million in business insurance proceeds relating to the outage of Clover Bar Energy Centre Unit 2 from March 8 until September 22 was recorded in the third quarter of 2010 and included in the results for Alberta commercial plants and portfolio optimization. The increase in the fair value of derivative instruments primarily reflected the impact of decreased Alberta forward power prices on CPLP's portfolio position, and unrealized gains on CPILP's foreign exchange contracts due to strengthening future prices for the Canadian dollar relative to the U.S. dollar. Indirect administration expenses included $7 million for the recognition of the obligation to EPCOR for operations and maintenance costs for the Rossdale plant and assets over the ten-year period ending in 2019.

Income taxes reflected the recognition of an $11 million future income tax liability relating to the investment in CPILP, as a result of the strategic alternatives review. Financing expenses for the third quarter of 2010 included $7 million of unrealized losses for the decrease in the fair value of two forward bond sale contracts that were entered into in the second quarter of 2010.

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

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

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

In the third quarter of 2009, the increase in the fair value of derivative instruments was primarily due to the impact of decreased forward Alberta power prices on CPLP's portfolio position and the impact of strengthening future prices for the Canadian dollar relative to the U.S. dollar on CPILP's foreign exchange contracts. This was partly offset by a decrease in the fair value of CPILP's natural gas supply contracts for the period before they were designated as hedges for accounting purposes on July 31, 2009.

## Quarterly Common Share Trading Information

The Company's common shares and Cumulative Rate Reset Preference Shares, Series 1 trade on the Toronto Stock Exchange under the symbols CPX and CPX.PR.A, respectively. The common shares began trading on June 26, 2009 and the Cumulative Rate Reset Preference Shares, Series 1 began trading on December 16, 2010.

| (unaudited) | Three months ended | | | | | | |
|---|---|---|---|---|---|---|---|
| | Dec 31, 2010 | Sept 30, 2010 | June 30, 2010 | Mar 31, 2010 | Dec 31, 2009 | Sept 30, 2009 | June 30, 2009 |
| Share price | | | | | | | |
| High | $24.84 | $24.20 | $23.39 | $23.00 | $21.78 | $22.39 | $23.00 |
| Low | $23.25 | $21.75 | $21.76 | $20.97 | $18.95 | $19.50 | $22.00 |
| Close | $23.65 | $24.10 | $22.14 | $22.50 | $21.37 | $19.75 | $22.35 |
| Volume traded (millions) | 3.4 | 2.4 | 4.4 | 7.6 | 6.5 | 12.1 | 5.8 |

As at March 7, 2011, the Company had 31.055 million common shares outstanding, 47.416 million special voting shares outstanding, 5 million Cumulative Rate Reset Preference Shares, Series 1 outstanding and one special limited voting share outstanding. The weighted average number of common shares outstanding on a diluted basis was 22.188 million for the year ended December 31, 2010. All of the outstanding special voting shares and the outstanding special limited voting share are held indirectly by EPCOR.

As at March 7, 2011, CPLP had 21.75 million general partnership units outstanding, 9.209 million common limited partnership units outstanding and 47.416 million exchangeable limited partnership units outstanding, which are exchangeable for 47.416 million common shares of the Company. All of the outstanding general partnership units and the outstanding common limited partnership units are held, indirectly, by the Company. All of the outstanding exchangeable limited partnership units are held indirectly by EPCOR.

As at March 7, 2011, CPILP had 56.1 million limited partnership units outstanding and 16.5 million of such units, representing 29.4% 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.

Consolidated Financial Statements of

# CAPITAL POWER CORPORATION

(In millions of dollars)
Year ended December 31, 2010 and six months ended December 31, 2009

## Management's responsibility for financial reporting

The preparation and presentation of the accompanying consolidated financial statements of Capital Power Corporation are the responsibility of management and the consolidated financial statements have been approved by the Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with Canadian generally accepted accounting principles. The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to March 8, 2011. Financial information presented elsewhere in this annual report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board of Directors.

The consolidated financial statements have been examined by KPMG LLP, the Company's external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with Canadian generally accepted accounting principles. The auditors' report outlines the scope of their audit examination and states their opinion.

The Board of Directors, through the Audit Committee, is responsible for ensuring management fulfils its responsibilities for financial reporting and internal controls. The Audit Committee, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and annual report and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management. The Audit Committee is also responsible for reviewing and recommending the annual appointment of the external auditors and approving the annual external audit plan.

On behalf of management,

Brian Vaasjo
President and Chief Executive Officer

Stuart Lee
Senior Vice President and
Chief Financial Officer

March 8, 2011

# CAPITAL POWER CORPORATION

Consolidated Financial Statements

Year ended December 31, 2010 and six months ended December 31, 2009

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**KPMG LLP**
**Chartered Accountants**
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Edmonton AB T5J 3V8
Canada

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# INDEPENDENT AUDITORS' REPORT

To the Shareholders

We have audited the accompanying consolidated financial statements of Capital Power Corporation ("the Company") which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009 and the consolidated statements of income, changes in owners' equity, comprehensive income and cash flows for the periods then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

## Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

## Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinions.

## Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2010 and December 31, 2009, and the consolidated results of its operations and its consolidated cash flows for the periods then ended in accordance with Canadian generally accepted accounting principles.

## Emphasis of Matter

We draw your attention to Note 2(b) to the consolidated financial statements which describes the early adoption of Canadian Institute of Chartered Accountants' ("CICA") Handbook Section 1582, "Busines Combinations", CICA Handbook Section 1601, "Consolidated Financial Statements" and CICA Handbook Section 1602, "Non-Controlling Interests". Our opinion is not qualified in respect of this matter.

KPMG LLP

Chartered Accountants

March 8, 2011

Edmonton, Canada

# CAPITAL POWER CORPORATION

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

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| Revenues | $ 1,760 | $ 1,008 |
| Energy purchases and fuel | 992 | 574 |
| | 768 | 434 |
| Operations, maintenance and direct administration | 230 | 102 |
| Indirect administration | 133 | 64 |
| Property taxes | 18 | 9 |
| Depreciation, amortization and asset retirement obligations accretion (note 7) | 197 | 92 |
| Foreign exchange losses | 1 | 4 |
| Gains on acquisitions and disposals (notes 3 and 5) | (30) | - |
| Net financing expenses (note 19) | 74 | 34 |
| | 623 | 305 |
| Income before income tax expense | 145 | 129 |
| Income tax expense (note 20) | 8 | 10 |
| Net income | $ 137 | $ 119 |
| Net income attributable to: | | |
| Non-controlling interests (note 15) | 126 | 98 |
| Common shareholders | 11 | 21 |
| Earnings per share (note 16) | | |
| Basic | $ 0.50 | $ 0.97 |
| Diluted | 0.50 | 0.89 |
| Weighted average number of common shares outstanding | | |
| Basic | 22,188,266 | 21,750,000 |
| Diluted | 22,188,266 | 78,375,000 |

See accompanying notes to consolidated financial statements.

# CAPITAL POWER CORPORATION

Consolidated Balance Sheets
(In millions of dollars)

As at December 31, 2010 and 2009

| | 2010 | 2009 |
|---|---|---|
| Assets | | |
| Current assets: | | |
| Cash and cash equivalents (note 27) | $ 56 | $ 52 |
| Accounts receivable | 271 | 275 |
| Income taxes recoverable | 6 | 29 |
| Inventories (note 6) | 55 | 63 |
| Prepaid expenses | 7 | 8 |
| Derivative instruments assets (note 22) | 152 | 146 |
| Future income tax assets (note 20) | 7 | 2 |
| Assets held for sale (note 5) | - | 36 |
| | 554 | 611 |
| Property, plant and equipment (note 7) | 3,597 | 3,237 |
| Power purchase arrangements (note 8) | 464 | 528 |
| Contract and customer rights and other intangible assets (note 9) | 203 | 184 |
| Derivative instruments assets (note 22) | 76 | 155 |
| Future income tax assets (note 20) | 63 | 61 |
| Goodwill (note 10) | 139 | 140 |
| Other assets (note 11) | 121 | 120 |
| | $ 5,217 | $ 5,036 |

See accompanying notes to consolidated financial statements.

Approved on behalf of the Board:

Donald Lowry
Director and Chairman of the Board

William Bennett
Director and Chairman of the Audit Committee

| | 2010 | 2009 (notes 2(b) and 35) |
|---|---|---|
| Liabilities and Owners' Equity | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | $ 304 | $ 339 |
| Derivative instruments liabilities (note 22) | 126 | 108 |
| Other current liabilities | 10 | 8 |
| Future income tax liabilities (note 20) | 21 | 21 |
| Current portion of long-term debt (note 12) | 235 | 247 |
| | 696 | 723 |
| Long-term debt (note 12) | 1,634 | 1,472 |
| Derivative instruments liabilities (note 22) | 95 | 102 |
| Other non-current liabilities (note 13) | 119 | 109 |
| Future income tax liabilities (note 20) | 95 | 95 |
| | 2,639 | 2,501 |
| Owners' equity: | | |
| Equity attributable to common shareholders | | |
| Share capital (note 16) | 820 | 477 |
| Contributed surplus (note 16) | 4 | 2 |
| Retained earnings | 3 | 7 |
| Accumulated other comprehensive (loss) income (note 17) | (3) | 3 |
| Retained earnings and accumulated other comprehensive (loss) income | - | 10 |
| | 824 | 489 |
| Non-controlling interests (note 15) | 1,754 | 2,046 |
| | 2,578 | 2,535 |
| Commitments and contingencies (notes 27, 30 and 31) | | |
| Subsequent events (note 34) | | |
| | $ 5,217 | $ 5,036 |

See accompanying notes to consolidated financial statements.

# CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Owners' Equity
(In millions of dollars)

| | Share capital (notes 4 and 16) | Contributed surplus (note 16) | Retained earnings (note 16) | Accumulated other comprehensive income (loss) | Equity attributable to common shareholders | Non-controlling interests (notes 2(b) and 35) (note 15) | Total |
|---|---|---|---|---|---|---|---|
| Equity as at July 1, 2009 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Net income | - | - | 21 | - | 21 | 98 | 119 |
| Common shares issued | 477 | - | - | - | 477 | - | 477 |
| Share-based compensation | - | 2 | - | - | 2 | - | 2 |
| Common share dividends | - | - | (14) | - | (14) | - | (14) |
| Changes in gains and losses on derivative instruments designated as cash flow hedges | - | - | - | 1 | 1 | (3) | (2) |
| Reclassification of losses on derivative instruments designated as cash flow hedges to net income | - | - | - | 6 | 6 | 25 | 31 |
| Unrealized foreign currency translation loss in self-sustaining foreign operations | - | - | - | (4) | (4) | (39) | (43) |
| Non-controlling interests in net assets acquired | - | - | - | - | - | 635 | 635 |
| Distributions to non-controlling interests | - | - | - | - | - | (69) | (69) |
| Issue of partnership units by subsidiaries | - | - | - | - | - | 1,305 | 1,305 |
| Issue of preferred shares | - | - | - | - | - | 98 | 98 |
| Preferred share dividends paid by subsidiary company | - | - | - | - | - | (4) | (4) |
| Equity as at December 31, 2009 | $ 477 | $ 2 | $ 7 | $ 3 | $ 489 | $ 2,046 | $ 2,535 |
| Net income | - | - | 11 | - | 11 | 126 | 137 |
| Issue of preferred shares | 122 | - | - | - | 122 | - | 122 |
| Share-based compensation | - | 2 | - | - | 2 | - | 2 |
| Common share dividends | - | - | (30) | - | (30) | - | (30) |
| Changes in gains and losses on derivative instruments designated as cash flow hedges | - | - | - | (2) | (2) | (36) | (38) |
| Reclassification of losses on derivative instruments designated as cash flow hedges to net income | - | - | - | 1 | 1 | 7 | 8 |
| Reclassification of ineffective portion of cash flow hedges to net income | - | - | - | - | - | 2 | 2 |
| Unrealized foreign currency translation loss in self-sustaining foreign operations | - | - | - | (5) | (5) | (24) | (29) |
| Distributions to non-controlling interests | - | - | - | - | - | (137) | (137) |
| Issue of partnership units by subsidiary | - | - | - | - | - | 27 | 27 |
| Preferred share dividends paid by subsidiary company | - | - | - | - | - | (14) | (14) |
| Exchange of CPLP units for common shares | 221 | - | 15 | - | 236 | (243) | (7) |
| Equity as at December 31, 2010 | $ 820 | $ 4 | $ 3 | $ (3) | $ 824 | $ 1,754 | $ 2,578 |

See accompanying notes to consolidated financial statements.

# CAPITAL POWER CORPORATION

Consolidated Statements of Comprehensive Income
(In millions of dollars)

| | Year ended December 31, 2010 | Six months ended December 31, 2009 (note 2(b)) |
|---|---|---|
| Net income | $ 137 | $ 119 |
| Other comprehensive income (loss), net of income taxes: | | |
| Changes in gains and losses on derivative instruments designated as cash flow hedges[1] | (38) | (2) |
| Reclassification of losses on derivative instruments designated as cash flow hedges to net income[2] | 8 | 31 |
| Reclassification of ineffective portion of cash flow hedges to net income[3] | 2 | - |
| Unrealized foreign currency translation loss in self-sustaining foreign operations[4] | (29) | (43) |
| | (57) | (14) |
| Total comprehensive income for the period | $ 80 | $ 105 |
| Total comprehensive income attributable to: | | |
| Non-controlling interests | | |
| Net Income attributable to non-controlling interests | 126 | 98 |
| Other comprehensive loss, net of income taxes attributable to non-controlling interests[3] (note 15) | (51) | (17) |
| | 75 | 81 |
| Common shareholders | $ 5 | $ 24 |

[1] For the year ended December 31, 2010, net of income tax recoveries of $19. For the six months ended December 31, 2009, net of income tax recoveries of $2.

[2] For the year ended December 31, 2010, net of reclassification of income tax recoveries of $1. For the six months ended December 31, 2009, net of reclassification of income tax recoveries of $3.

[3] For the year ended December 31, 2010 and six months ended December 31, 2009, net of income tax expense of nil.

[4] For the year ended December 31, 2010, net of income tax expenses of $1. For the six months ended December 31, 2009, net of income tax expense of nil.

See accompanying notes to consolidated financial statements.

# CAPITAL POWER CORPORATION

Consolidated Statements of Cash Flows
(In millions of dollars)

| | Year ended December 31, 2010 | Six months ended December 31, 2009 (note 2(b)) |
|---|---|---|
| **Operating activities:** | | |
| Net income | $ 137 | $ 119 |
| Adjustments to reconcile net income to cash flows from operating activities: | | |
| Depreciation, amortization and asset retirement obligations accretion (note 7) | 197 | 92 |
| Gains on acquisitions and disposals (notes 3 and 5) | (30) | - |
| Fair value changes on derivative instruments | 36 | (56) |
| Unrealized foreign exchange losses | 1 | 3 |
| Future income taxes (note 20) | (2) | 9 |
| Other | 15 | 4 |
| | 354 | 171 |
| Change in non-cash working capital (note 18) | 16 | 2 |
| | 370 | 173 |
| **Investing activities:** | | |
| Property, plant and equipment and other assets | (337) | (230) |
| Change in non-cash working capital (note 18) | (28) | 3 |
| Proceeds on sale of power syndicate agreement (note 5) | 64 | - |
| Business acquisition, net of acquired cash (notes 3 and 4) | (205) | (1,293) |
| Other | 3 | - |
| | (503) | (1,520) |
| **Financing activities:** | | |
| Proceeds from issue of long-term debt | 425 | 1,040 |
| Repayment of long-term debt | (247) | (120) |
| Issue of common shares (notes 4 and 16) | 1 | 500 |
| Issue of preferred shares (note 16) | 125 | - |
| Issue of subsidiary preferred shares (note 15) | - | 100 |
| Distributions to non-controlling interests | (112) | (58) |
| Common share dividends paid | (30) | (7) |
| Preferred share dividends paid by subsidiary | (13) | (4) |
| Share issue costs (notes 4, 15 and 16) | (4) | (35) |
| Debt issue costs | (5) | (13) |
| | 140 | 1,403 |
| Foreign exchange losses on cash held in a foreign currency | (3) | (4) |
| Increase in cash and cash equivalents | 4 | 52 |
| Cash and cash equivalents, beginning of period | 52 | - |
| Cash and cash equivalents, end of period | $ 56 | $ 52 |
| **Supplementary cash flow information:** | | |
| Interest (paid) net of interest received | $ (102) | $ (45) |
| Income taxes recovered net of income taxes (paid) | 9 | (1) |

See accompanying notes to consolidated financial statements.

**1. Description of business:**

Capital Power Corporation (the Company or Capital Power) builds, owns and operates power plants and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities. The Company operates in one reportable business segment within the geographic areas of Canada and the United States (U.S.), with its head office located in Edmonton, Alberta.

The common shares of the Company are traded on the Toronto Stock Exchange under the symbol "CPX".

**2. Summary of significant accounting policies:**

(a) Basis of presentation:

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Amounts are in Canadian dollars unless otherwise indicated. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

These audited consolidated financial statements include the accounts of Capital Power, its subsidiaries, and its proportionate share of assets, liabilities, revenues and expenses of joint ventures, as well as the accounts of the Company's approximate 29.6% interest in Capital Power Income L.P. (CPILP) (December 31, 2009 – 30.5%), formerly EPCOR Power L.P. (name changed effective November 5, 2009), and the Company's approximate 39.5% interest in Capital Power LP (CPLP) (December 31, 2009 – 27.8%). Capital Power controls CPILP and CPLP, as defined under GAAP, and accordingly they are considered subsidiaries of Capital Power.

All significant intercompany balances and transactions have been eliminated on consolidation.

The Company was incorporated on May 1, 2009, but did not have any results from operations or significant cash flows in the period from May 1 to June 30, 2009. Accordingly, the Company's statements of income, comprehensive income and cash flows reflect comparative information only for the six months ended December 31, 2009.

(b) Changes in significant accounting policies:

**Business combinations, consolidated financial statements and non-controlling interests**

In January 2009, the Canadian Institute of Chartered Accountants (CICA) issued Handbook Section 1582 – Business Combinations which replaces Handbook Section 1581 – Business Combinations and provides the Canadian equivalent to IFRS 3 – Business Combinations. In January 2009, the CICA also issued Handbook Sections 1601 – Consolidated Financial Statements and 1602 – Non-controlling Interests which replace Handbook Section 1600 – Consolidated Financial Statements. Section 1602 is the equivalent to the corresponding provisions of IAS 27 – Consolidated and Separate Financial Statements. Effective January 1, 2010, the Company elected, in accordance with the transitional provisions of these sections, to early adopt these new accounting standards to minimize the impact of adopting International Financial Reporting Standards (IFRS) in 2011. The Company would otherwise have been required to adopt the IFRS equivalents of these new accounting standards effective January 1, 2011.

**2. Summary of significant accounting policies, continued:**

(b) Changes in significant accounting policies, continued:

**Business combinations, consolidated financial statements and non-controlling interests, continued**

The impacts of adopting these standards, as they pertain to current period and prospective business combinations, include:

- business combinations are measured at the fair value of the identifiable assets acquired and liabilities assumed, including the fair value of contingent consideration and the fair value attributable to non-controlling interests;
- acquisition-related costs are expensed as incurred; and
- changes in non-controlling interests subsequent to the Company's acquisition of control, which do not result in the Company's loss of control, are accounted for as equity transactions.

The Company's consolidated financial statements reflect, retrospectively, the following changes to the presentation and disclosure of non-controlling interests:

- non-controlling interests are presented as a separate component of owners' equity in the consolidated balance sheets and statements of changes in owners' equity; and
- net income and other comprehensive income are attributed to the Company's common shareholders and non-controlling interests on the consolidated statements of income and other comprehensive income.

As a result of the application of Section 1582, the Company recognized the following relating to the Island Generation Facility acquisition (Island Generation)(note 3):

- less than $1 million of acquisition costs included within indirect administration expenses for the year ended December 31, 2010; and
- a bargain purchase gain of $2 million included within gains on acquisitions and disposals for the year ended December 31, 2010.

As a result of the application of Section 1602, the Company recognized an increase of $22 million to retained earnings relating to the exchange of CPLP units for common shares (note 16), and the resulting reduction in non-controlling interests. The increase was partially offset by a $7 million increase in future income tax liabilities attributable to common shareholders resulting from the reduction in non-controlling interests.

(c) Measurement uncertainty:

The preparation of the Company's financial statements, in accordance with Canadian GAAP, requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions.

For certain accounting measures such as determining asset impairments, purchase price allocations for business combinations, recording financial assets and liabilities, recording certain non-financial derivatives and for certain disclosures, the Company is required to estimate the fair value of certain assets or obligations. Estimates of fair value may be based on readily determinable market values or on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

Estimates of the value of electricity and natural gas consumed by customers but not billed until subsequent to year-end are based on volume data provided by the parties responsible for delivering the commodity and contracted prices.

**2. Summary of significant accounting policies, continued:**

(c) Measurement uncertainty, continued:

Depreciation and amortization is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of common life characteristics of common assets.

Measurement of the Company's asset retirement obligations and the related accretion expense requires the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required and related future cash flows.

Income taxes are determined based on estimates of the Company's current income taxes and estimates of future income taxes resulting from temporary tax differences. Future income tax assets are assessed to determine the likelihood that they will be realized from future taxable income. To the extent that realization is not considered likely, a valuation allowance is recorded and charged against income in the period that the allowance is created or revised.

As future events and their effects cannot be determined with precision, actual results could differ from these estimates. Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

(d) Revenue recognition:

Revenues from the sales of electricity and natural gas are recognized on delivery or availability for delivery under take-or-pay contracts. These revenues include an estimate of the value of electricity and natural gas consumed by customers, but billed subsequent to period-end.

Power Purchase Agreements (PPAs) are a form of long-term sales arrangement between the owner of a generation unit and the buyer of the PPA to purchase power and steam on a predetermined basis. As described in note 2(q), PPA's may be classified as a lease (either operating or capital) with the corresponding income from the PPA recognized in revenue in accordance with the lease classification standard. For those PPAs that are not considered to contain a lease, income earned on the PPA is recognized in revenue as described in the paragraphs below.

Revenues from certain of the Company's power generation plants are recognized on delivery of output or on availability for delivery as prescribed by the respective PPA. Revenue from certain long-term contracts with fixed payments is recognized at the lower of (1) the megawatt hours (MWhs) made available during the period multiplied by the billable contract price per MWh and (2) an amount determined by the MWhs made available during the period, multiplied by the average price per MWh over the term of the contract from the date of acquisition. Any excess of the contract price over the average price is recorded as deferred revenue.

The Company recognizes revenue from its Alberta generation units operating under acquired PPAs as described in note 2(k).

Revenues also include realized and unrealized gains and losses from derivatives used in the risk management of the Company's generation activities related to commodity prices and foreign currency risk, and from the Company's proprietary trading activities. Realized gains and losses are recognized when the settlement occurs and unrealized gains and losses are recorded as revenue based on the related changes in fair value at the end of each reporting period.

**2. Summary of significant accounting policies, continued:**

(e) Financial instruments:

Financial assets are identified and classified as either 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.

Financial assets and financial liabilities held for trading are measured at fair value with the changes in fair value reported in net income. Financial assets held to maturity, loans and receivables and financial liabilities other than those held for trading are measured at amortized cost. Available-for-sale financial assets are measured at fair value with changes in fair value reported in other comprehensive income until the financial asset is disposed of, or becomes impaired. Investments in equity instruments classified as available for sale that do not have quoted market prices in an active market are measured at cost.

Upon initial recognition, the Company may designate financial instruments as held for trading when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis. The Company has designated its cash and cash equivalents as held for trading. All other non-derivative financial assets not meeting the Company's criteria for designating as held for trading are classified as available for sale, loans and receivables or held to maturity.

Financial assets purchased or sold, where the contract requires the asset to be delivered within an established timeframe, are recognized on a settlement date basis.

Transaction costs on financial assets and liabilities classified as other than held for trading are capitalized and amortized over the expected life of the instrument, based on contractual cash flows, utilizing the effective interest method. The effective interest method calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

(f) Derivative instruments and hedging activities:

To reduce its exposure to movements in energy commodity prices, interest rate changes, and foreign currency exchange rates, the Company uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, and option contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments assets or derivative instruments liabilities except for embedded derivatives instruments that are clearly and closely linked to their host contract and the combined instrument is not measured at fair value. Any contract to buy or sell a non-financial item is not treated as a non-financial derivative if that contract was entered into and continues to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company’s expected purchase, sale or usage requirements. All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value of the effective portion of the derivatives are recorded in other comprehensive income. The Company accounts separately for any embedded derivatives in any hybrid instruments issued or acquired. The Company does not account for foreign currency derivatives embedded in non-financial instrument host contracts when the currency that is commonly used in contracts to purchase or sell non-financial items in the economic environment is that currency in which the transaction takes place.

**2. Summary of significant accounting policies, continued:**

(f) Derivative instruments and hedging activities, continued:

The Company uses financial contracts-for-differences (or fixed-for-floating swaps) to hedge the Company's exposure to fluctuations in electricity prices. Under these instruments, the Company agrees to exchange, with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified timeframe.

The Company uses non-financial forward delivery derivatives to manage the Company's exposure to fluctuations in natural gas prices related to its natural gas customer contracts and obligations arising from its natural gas fired generation facilities. Under these instruments, the Company agrees to sell or purchase natural gas at a fixed price for delivery of a pre-determined quantity under a specified timeframe.

Foreign exchange forward contracts are used by the Company to manage foreign exchange exposures, consisting mainly of U.S dollar exposures, resulting from anticipated transactions denominated in foreign currencies. For transactions involving the development or acquisition of property, plant and equipment, when the real or anticipated transaction subsequently results in the recognition of a financial asset, the associated gains or losses on hedging derivatives recognized in other comprehensive income are included in the initial carrying amount of the asset acquired in the same period or periods during which the asset acquired affects net income.

The Company may use physical or financial commodity derivative trades which are transacted with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities. Such trades are recognized on a net basis in the Company's revenues.

The Company may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Company documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retrospective and prospective basis. The Company uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in commodity prices. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while the ineffective portion is recognized in energy revenues or energy purchases and fuel, as appropriate. The amounts recognized in accumulated other comprehensive income are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income or when the hedged item becomes probable of not occurring. The Company has not designated any fair value hedges at the balance sheet date.

A hedging relationship is discontinued if the hedge relationship ceases to be effective, if the hedged item is an anticipated transaction and it is probable that the transaction will not occur by the end of the originally specified time period, if the Company terminates its designation of the hedging relationship, or if either the hedged or hedging instrument ceases to exist as a result of its maturity, expiry, sale, termination or cancellation and is not replaced as part of the Company's hedging strategy.

**2. Summary of significant accounting policies, continued:**

(f) Derivative instruments and hedging activities, continued:

If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive income and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the same period as the corresponding gains or losses on the hedged item. When it is no longer probable that an anticipated transaction will occur within the originally determined period and the associated cash flow hedge has been discontinued, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the period.

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized as described above. The fair value of derivative instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter price quotations by reference to bid or asking price as appropriate, in active markets. In illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

(g) Income taxes:

The Company's Canadian subsidiaries are subject to income taxes pursuant to the Income Tax Act (Canada) (ITA) and provincial income tax acts. The Company's U.S. subsidiaries are subject to income tax pursuant to U.S. federal and state tax laws.

The Company follows the asset and liability method of accounting for income taxes. Under this method, current income taxes are recognized for the estimated income taxes payable or recoverable for the current year. Future income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted rates of tax expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on future tax assets and liabilities is recognized in income in the period that includes the date of enactment or substantive enactment.

(h) Cash and cash equivalents:

Cash and cash equivalents include cash or highly liquid, investment-grade short-term investments with original terms to maturity of three months or less and are recorded at fair market value.

**2. Summary of significant accounting policies, continued:**

(i) Inventories:

Parts and other consumables and coal, the majority of which are consumed by the Company in the provision of its goods and services, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of any assembled inventory includes direct labour, materials and directly attributable overhead. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Natural gas inventory held in storage for trading purposes is recorded at fair value less costs to sell, as measured by the one-month forward price of natural gas. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstances.

(j) Property, plant and equipment:

Property, plant and equipment are recorded at cost and include contracted services, materials, interest, direct and indirect labour, directly attributable overhead costs, asset retirement costs, development costs associated with specific property, plant and equipment, and net revenues during the pre-operating period. Contributions received for financing the costs of assets are recorded as a reduction of the related asset cost.

Depreciation on property, plant and equipment is provided on the straight-line basis over their estimated useful lives. No depreciation is provided on construction work in progress.

The Company capitalizes interest during construction to provide for the costs of borrowing on construction activities. Where project specific debt is not used to finance construction, interest is applied during construction using the weighted average cost of debt incurred on the Company's external borrowings used to finance qualifying assets.

(k) Power purchase arrangements:

Acquired PPAs are reflected on the consolidated balance sheet as power purchase arrangements and are recorded at cost and are amortized over their terms on a straight-line basis.

Under the terms of the Alberta PPAs, the Company is obligated to make fixed and variable payments to the owners of the underlying generation units over their respective terms. Such amounts are recorded as operating expenses as incurred. At December 31, 2010, the remaining term of the 20-year Sundance PPA is approximately 10 years. The Company was also obligated to make fixed and variable payments to the buyer of the Battle River PPA, in proportion to its effective ownership interest, until the sale of the Company’s remaining interest in the Battle River Power Syndicate Agreement (Battle River PSA) was completed in 2010 as described in note 5.

The Company’s Alberta PPAs are owned under equity syndication agreements with an equity syndicate. Under the terms of the agreements, the syndicate members receive their proportionate share of the committed generating capacity in exchange for their proportionate share of the price paid for the Alberta PPAs and all payments to the generation unit owners.

The Company’s investment in the Alberta PPAs and its related revenues and expenses are recorded on a proportionate basis, after deducting the equity syndicate’s share.

The CPILP PPAs reflect the cost to acquire long-term sales contracts under which revenue is earned by CPILP’s generation units. The CPILP PPAs are amortized over the remaining terms of the contracts.

**2. Summary of significant accounting policies, continued:**

(l) Contract and customer rights and other intangible assets:

Contract rights include acquired management and operations agreements and water rights. Costs assigned to contract rights related to management and operations agreements are amortized on a straight-line basis, from the dates of acquisition, over the remaining contract terms which range from 4 to 56 years. Water rights associated with acquired hydroelectric power generation plants are recorded at cost and are amortized over the remaining useful lives of the associated property, plant and equipment.

Other rights include the cost of land lease agreements for use in wind power projects in British Columbia and Ontario and coal supply access rights relating to the Keephills 3 Project (note 30(a)). The lease rights are amortized on a straight-line basis over the estimated useful lives of the related wind power assets, commencing when those assets are constructed and commissioned for service. The access rights will be amortized over the life of the coal supply agreement and amortization will commence when the Keephills 3 plant is commissioned for service.

Other intangible assets, which include the costs of acquired software, are amortized over the estimated useful lives of the assets which range from 1 to 10 years.

Customer rights represent the costs to acquire the rights to a long-term sales contract for the output of the Brown Lake plant. The costs are amortized on a straight-line basis over the 30-year term of the contract.

(m) Goodwill:

Goodwill is the cost of an acquisition less the fair value of the net assets of an acquired business. Goodwill is tested for impairment annually, or more often if events and circumstances indicate that goodwill may be impaired, by comparing the fair value of each reporting unit to which the goodwill relates to the carrying amount, including goodwill, of each reporting unit. If the carrying amount of the reporting unit exceeds its fair value, indicating an impairment, a second test is performed to measure the amount of the impairment. In the second test, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the impairment loss, if any.

(n) Other assets:

Loans and other long-term receivables include promissory notes receivable and amounts due from customers more than one year from the balance sheet date and will be repaid between 2011 and 2025. Also included in loans and other long-term receivables are long-term receivables related to services provided under the long-term services arrangement component of the Oxnard PPA that will be collected over the remaining term of the PPA.

Investments in which the Company exercises significant influence are accounted for using the equity method. Other investments are classified as available for sale and are recorded at fair value unless the investments do not have a quoted market price in an active market in which case the investments are recorded at cost. Investments recorded at cost for which there is a decline in fair value below cost that is other than temporary are written down and the loss is recognized in net income.

(o) Impairment of long-lived assets:

The Company reviews the valuation of long-lived assets subject to depreciation and amortization when events or changes in circumstances may indicate or cause a long-lived asset's carrying amount to exceed the total undiscounted future cash flows expected from its use and eventual disposition. An impairment loss, if any, would be recorded as the excess of the carrying amount of the asset over its fair value, measured by either market value, if available, or estimated by calculating the present value of expected future cash flows related to the asset.

**2. Summary of significant accounting policies, continued:**

(p) Asset retirement obligations:

The Company recognizes asset retirement obligations in the period in which they are incurred, unless the fair value cannot be reasonably determined. A corresponding asset retirement cost is added to the carrying amount of the associated long-lived asset, and is depreciated over the estimated useful life of the asset. Accretion of the liability due to the passage of time is an operating expense, and is recorded over the estimated time period until settlement of the obligation.

The Company has recorded asset retirement obligations for its power generation plants and Genesee coal mine as it is legally required to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. Asset retirement obligations for the coal mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

(q) Leases or arrangements containing a lease:

The Company has entered into PPAs to sell power at predetermined rates. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the Company's property, plant and equipment in return for payment and such types of arrangements are classified as either capital or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property to the PPA counterparty are classified as capital leases. PPAs where a significant portion of risks and rewards of ownership are retained by the lessor are classified as operating leases. Income on operating leases is recorded as revenue on a straight-line basis over the period of the lease.

Finance income related to leases or arrangements accounted for as direct financing leases are recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is composed of net minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying amount of the leased property. Unearned finance income is deferred and recognized in net income over the lease term.

Payments received under PPAs classified as capital leases are segmented into those for the lease and those for other elements on the basis of their relative fair value.

(r) Foreign currency translation:

The Company's self-sustaining foreign operations are translated to Canadian dollars using the current rate method. Assets and liabilities are translated at the exchange rate in effect at the balance sheet date. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in accumulated other comprehensive income until there is a reduction in the Company's net investment in the foreign operations.

(s) Employee future benefits:

The employees of the Company are either members of the Local Authorities Pension Plan (LAPP) or other defined contribution or benefit plans.

The LAPP is a multiemployer defined benefit pension plan. The Trustee of the plan is the Treasurer of Alberta and the plan is administered by a Board of Trustees. The Company and its employees make contributions to the plan at rates prescribed by the Board of Trustees to cover costs under the plan. Since the plan is a multiemployer plan, it is accounted for as a defined contribution plan. Accordingly, the Company does not recognize its share of any plan surplus or deficit.

**2. Summary of significant accounting policies, continued:**

(s) Employee future benefits, continued:

The Company maintains additional defined contribution and defined benefit pension plans to provide pension benefits to those employees (comprising less than 45% of total employees of Capital Power) who are not otherwise served by LAPP.

The Company accrues its obligations for its defined benefit pension plans net of plan assets in the employee future benefits liabilities included in other non-current liabilities. The cost of pension benefits earned by employees is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. For the purpose of calculating the expected return on plan assets, those assets are valued at quoted market value. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Past service costs from plan amendments are amortized on a straight-line basis over the estimated average remaining service of employees active at the date of amendment. The excess of the net cumulative unamortized actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the market value of plan assets is amortized over the estimated average remaining service period of the active employees.

The Company has an unfunded long-term disability benefit plan which provides provincial health care premiums, health and dental benefits, and required pension contributions for current disabled employees. The plan is a defined benefit plan and the obligation related to long-term disability benefits is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of future health care costs, salary escalation for estimating future benefit contributions, recovery and termination experience, and inflation rates. The Company's accrual for the long-term disability benefit plan is reflected in the employee future benefits liabilities included in other non-current liabilities. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the balance sheet date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Actuarial gains or losses on the accrued benefit obligation arise from differences between actual and expected experience and from changes in the actuarial assumptions used to determine the accrued benefit obligation. Actuarial gains and losses are recognized in income immediately.

(t) Share-based payments:

The Company determines the fair value of share-based payments to employees that are settled by the issuance of equity using a binomial option pricing model at the date of grant. The fair value of employee granted options is recognized over the vesting period as a compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to share capital. The Company has incorporated an estimated forfeiture rate for stock options that will not vest into its determination of share-based compensation for each period.

Obligations for payments for performance share units, which are classified as a liability on the consolidated balance sheet, are accrued as compensation expense over the vesting period using the Monte Carlo model to calculate the intrinsic value of the performance share units.

Share-based payments to non-employees are measured at the fair value of the services received or the fair value of the equity instruments issued if it is determined the fair value of the services cannot be reliably measured, and are recorded at the date the services are received.

**2. Summary of significant accounting policies, continued:**

(u) Earnings per share:

Basic earnings per share is calculated by dividing income available to common shareholders by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated on the treasury stock method, by dividing income available to common shareholders, adjusted for the effects of dilutive securities, by the weighted average number of common shares outstanding during the period and all additional common shares that would have been outstanding had all potential dilutive common shares been issued. This method computes the number of additional shares by assuming all outstanding options, for which the average market price of the common shares for the period exceeds the exercise price, are exercised. The total number of shares is then reduced by the number of common shares assumed to be repurchased from the total issuance proceeds and unrecognized share based compensation, using the average market price of the Company's common shares for the period. When the average market price of the Company's common shares for a period is below the exercise price of the granted options, the options do not have a dilutive effect on earnings per share. Exchangeable common limited partnership units of CPLP, as described in note 4, are exchangeable for common shares of the Company and can have a dilutive effect on earnings per share as described in note 16.

(v) Government assistance:

Government assistance is recognized when it is more likely than not that it will be realized and such assistance is recorded as a reduction to the related expense or asset.

(w) Offsetting of financial assets and financial liabilities:

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to set-off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

(x) Long-term debt discounts, premiums and issue expenses:

Debenture discounts, premiums and issue expenses with respect to long-term debt are amortized over the term of the related debt using the effective interest rate method.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**3. Acquisition of Island Generation Facility:**

On October 19, 2010, the Company's subsidiary, CPLP, acquired Island Generation, a 275 megawatt (MW) gas-fired combined cycle power plant at Campbell River, British Columbia, by purchasing a 100% interest in V.I. Power Limited Partnership from a third party. The acquisition of Island Generation supports the Company's growth strategy.

Island Generation is fully contracted from April 1, 2010 to April 2022 under a tolling arrangement with a third party. The third party to the tolling arrangement is responsible for the fuel supply to the facility.

The total fair value of consideration paid was $205 million in cash. The acquisition's $205 million purchase price consists of the acquisition's $207 million base purchase price, less normal working capital adjustments of $2 million and was allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

| | |
|---|---|
| Accounts receivable | $ 2 |
| Prepaid expenses | 1 |
| Property, plant and equipment | 218 |
| Accounts payable and accrued liabilities | (3) |
| Asset retirement obligations | (2) |
| Future income tax liability, non-current | (9) |
| Fair value of net assets acquired | $ 207 |

The $2 million excess of the fair value of net assets acquired over the consideration paid was recorded as a bargain purchase gain. The bargain purchase gain is included within gains on acquisitions and disposals for the year ended December 31, 2010.

The $2 million allocated to accounts receivable represents both the estimated fair value and the gross contractual accounts receivable. As at October 19, 2010, the Company estimated that all of the contractual cash flows are to be collected.

The results of operations of Island Generation are included in the Company's consolidated statements of income and retained earnings from the date of acquisition. Such results of operations and the related assets and liabilities at the balance sheet date are included in the consolidated balance sheet. Since the acquisition date of October 19, 2010, $8 million of revenue and $3 million of net income from Island Generation is included in the consolidated statement of income for the year ending December 31, 2010. Had the acquisition occurred at the beginning of the year ended December 31, 2010, the combined entity of the Company and Island Generation would have had a total of $1,797 million of revenue and $135 million of net income.

In conjunction with the acquisition of Island Generation, the Company incurred less than $1 million in acquisition costs which have been recorded on the Company's statement of income as indirect administration expenses for the year ended December 31, 2010.

**4. Acquisition of assets and initial public offering:**

Pursuant to its initial public offering on July 9, 2009, the Company issued 21,750,000 common shares at a price of $23.00 per share for net proceeds of $468 million after deducting underwriting commissions of $25 million and offering expenses of $7 million. The net proceeds of the offering were used to purchase a 27.8% equity interest in CPLP. CPLP purchased substantially all of the power generation assets from EPCOR Utilities Inc. (EPCOR), effective July 1, 2009 through the following series of transactions (the Reorganization):

- Formation of CPLP: Capital Power and a wholly-owned subsidiary of Capital Power (Capital Power LP Holdings Inc.) formed CPLP. Capital Power acquired one general partner unit (GP Unit) and became the initial general partner of CPLP. Capital Power LP Holdings Inc. acquired one common limited partnership unit and as a result, became the initial limited partner in CPLP.
- Sale of EMCC Limited to Capital Power: EPCOR transferred all of the outstanding common shares of EMCC Limited to Capital Power in return for payment of approximately $468 million in cash.
- Contribution of Assets by EMCC Limited to CPLP: EMCC Limited contributed substantially all of its assets (consisting primarily of certain securities of subsidiary entities, its class B shares in the capital of CPI Investments Inc., formerly EPLP Investments Inc. and promissory note of CPI Investments Inc.) to CPLP in return for 21,750,000 GP Units. Capital Power transferred its GP Unit in CPLP to EMCC Limited and as a result EMCC Limited became the general partner of CPLP. Following the completion of these transactions, EMCC Limited was renamed Capital Power GP Holdings Inc.
- Sale of assets net of liabilities by EPCOR Power Development Corporation (EPDC) to CPLP: EPDC transferred substantially all of its assets (consisting primarily of assets related to Genesee Units 1 and 2, the Genesee Coal Mine joint venture and certain interests in partnerships) to CPLP in return for 56,625,000 exchangeable limited partnership units of CPLP and approximately $896 million in cash. CPLP financed the cash payment with the proceeds from a long-term debt obligation to EPCOR.

Immediately following completion of the Reorganization, Capital Power held general partnership units of CPLP representing an ownership interest of approximately 27.8% of CPLP while EPCOR held 56,625,000 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. Each exchangeable limited partnership unit is accompanied by a special voting share in the capital of Capital Power which entitles the holder to a vote at Capital Power shareholder meetings, subject to the restriction that such special voting shares must at all times represent not more than 49% of the votes attached to all Capital Power common shares and special voting shares, taken together. Capital Power and EPCOR have agreed that for so long as EPCOR holds not less than a 20% interest in the common shares of Capital Power, the number of directors will not be less than nine. The special voting shares also entitle EPCOR, voting separately as a class, to nominate and elect a maximum of four directors of Capital Power of the current twelve directors on Capital Power's board of directors. Since EPCOR's representation on the board of directors does not represent a controlling vote and since Capital Power GP Holdings Inc., a subsidiary of Capital Power, is the general partner of CPLP, Capital Power will have control over CPLP. On that basis, the operations of CPLP will be consolidated by Capital Power for financial statement purposes.

Immediately following completion of the Reorganization, CPLP held 49% and EPCOR held 51% of the voting rights in CPI Investments Inc. CPI Investments Inc. owns the approximate 29.6% interest (30.6% interest at July 1, 2009) in CPILP previously owned by EPCOR. However, CPLP is entitled to all of the economic interest in CPI Investments Inc. Under GAAP, CPLP is the primary beneficiary of CPI Investments Inc. and accordingly, effective July 1, 2009, Capital Power will consolidate the financial results of CPILP.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**4. Acquisition of assets and initial public offering, continued:**

The $468 million purchase price was allocated to the assets acquired and liabilities assumed based on estimated fair values as follows:

| | |
|---|---|
| Cash and cash equivalents | $ 71 |
| Other current assets | 463 |
| Property, plant and equipment | 3,136 |
| Power purchase arrangements | 582 |
| Contract and customer rights and other intangible assets | 169 |
| Derivative instruments assets – non-current | 74 |
| Future income tax assets – non-current | 64 |
| Acquired goodwill | 145 |
| Other non-current assets | 122 |
| Assets held for sale | 36 |
| Current liabilities | (387) |
| Long-term debt (including current portion) | (1,761) |
| Derivative instruments liabilities – non-current | (65) |
| Future income tax liabilities – non-current | (137) |
| Other non-current liabilities | (107) |
| | 2,405 |
| Non-controlling interests in net assets (note 15) | (1,937) |
| Fair value of net assets acquired | $ 468 |

The values of the assets and liabilities above reflect management's best estimates.

The $169 million of contract and customer rights and other intangibles includes $106 million of contract rights, $42 million of coal supply access rights and $21 million of other rights which include customer rights, lease rights, software intangibles and emission credits. Substantially all of the acquired contract and customer rights and other intangible assets are subject to amortization as described in note 2(l).

The amount allocated to acquired goodwill is not deductible for income tax purposes.

Non-controlling interests in net assets acquired include preferred share and other non-controlling interests in CPILP at the acquisition date of $122 million and $383 million respectively, as well as limited partnership units of CPLP issued to non-controlling interests as a part of the Reorganization of $1,302 million. The remaining non-controlling interests of $130 million relate to the non-controlling interest in net assets acquired.

The results of operations of the subsidiaries and assets acquired from EPCOR are included in the Company's consolidated statements of income, comprehensive income, retained earnings and accumulated other comprehensive income from July 1, 2009, the effective date of the acquisition.

Capital Power has entered into various agreements with EPCOR to provide for certain aspects of the separation of the business of Capital Power from EPCOR, to provide for the continuity of operations and services and to govern the ongoing relationships between the two groups of entities.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**5. 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 in the first quarter of 2010, included within gains on acquisitions and disposals. 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. described in note 4. 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 attributable to common shareholders of the sale of the Battle River PSA in the year ended December 31, 2010 was nil.

**6. Inventories:**

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Parts and other consumables | $ 42 | $ 47 |
| Coal | 9 | 8 |
| Natural gas held in storage for trading purposes | 4 | 8 |
| | $ 55 | $ 63 |

Inventories expensed upon usage during the year ended December 31, 2010 of $67 million (six months ended December 31, 2009 - $14 million) were charged to energy purchases and fuel, and operations, maintenance and direct administration. Write-downs of inventories of $1 million were expensed in operations, maintenance and direct administration in the year ended December 31, 2010 (six months ended December 31, 2009 – nil). There were no reversals of previous write-downs in the year ended December 31, 2010 (2009 – nil). At December 31, 2010 and 2009, no inventories were pledged as security for liabilities.

**7. Property, plant and equipment:**

| December 31, 2010 | Composite Depreciation Rate | Cost | Accumulated Depreciation | Net Book Value |
|---|---|---|---|---|
| Land | None | $ 68 | $ - | $ 68 |
| Plant and equipment | 5.2% | 2,859 | 186 | 2,673 |
| Contributions | 11.9% | (36) | (6) | (30) |
| Construction work in progress | None | 886 | - | 886 |
| | | $ 3,777 | $ 180 | $ 3,597 |

| December 31, 2009 | Composite Depreciation Rate | Cost | Accumulated Depreciation | Net Book Value |
|---|---|---|---|---|
| Land | None | $ 68 | $ - | $ 68 |
| Plant and equipment | 5.3% | 2,589 | 58 | 2,531 |
| Contributions | 12.1% | (28) | (2) | (26) |
| Construction work in progress | None | 664 | - | 664 |
| | | $ 3,293 | $ 56 | $ 3,237 |

(Tabular amounts in millions of dollars, except shares and per share amounts)

**7. Property, plant and equipment, continued:**

Depreciation, amortization and asset retirement obligations accretion expense is comprised of:

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| Depreciation on assets in service | $ 142 | $ 65 |
| Amortization of PPAs | 47 | 24 |
| Gain on settlement of asset retirement obligations | (7) | (4) |
| Accretion on asset retirement obligations (note 14) | 6 | 3 |
| Amortization of contract and customer rights and other intangible assets | 5 | 4 |
| Amortization of contributions | (4) | (2) |
| Other | 8 | 2 |
| | $ 197 | $ 92 |

Interest capitalized to property, plant and equipment for the year ended December 31, 2010 is $44 million (six months ended December 31, 2009 - $20 million).

**8. Power purchase arrangements:**

| December 31, 2010 | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Alberta PPAs | $ 140 | $ 18 | $ 122 |
| CPILP PPAs | 388 | 46 | 342 |
| | $ 528 | $ 64 | $ 464 |

| December 31, 2009 | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Alberta PPAs | $ 140 | $ 6 | $ 134 |
| CPILP PPAs | 412 | 18 | 394 |
| | $ 552 | $ 24 | $ 528 |

**9. Contract and customer rights and other intangible assets:**

| December 31, 2010 | Cost | Accumulated amortization | Net book value |
|---|---|---|---|
| Contract rights | $ 101 | $ 4 | $ 97 |
| Other rights | 74 | - | 74 |
| Emission credits | 19 | - | 19 |
| Software intangibles | 13 | 4 | 9 |
| Customer rights | 4 | - | 4 |
| | $ 211 | $ 8 | $ 203 |

(Tabular amounts in millions of dollars, except shares and per share amounts)

**9. Contract and customer rights and other intangible assets, continued:**

| | December 31, 2009 | | |
|---|---|---|---|
| | Cost | Accumulated amortization | Net book value |
| Contract rights | $ 105 | $ 2 | $ 103 |
| Other rights | 56 | - | 56 |
| Emission credits | 11 | 1 | 10 |
| Software intangibles | 11 | 1 | 10 |
| Customer rights | 5 | - | 5 |
| | $ 188 | $ 4 | $ 184 |

**10. Goodwill:**

The changes in the carrying amount of goodwill are as follows:

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| Balance, beginning of period | $ 140 | $ - |
| Acquired goodwill (note 4) | - | 145 |
| Foreign exchange translation adjustment | (1) | (5) |
| Balance, end of period | $ 139 | $ 140 |

**11. Other assets:**

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Loans and other long-term receivables | $ 53 | $ 48 |
| Net investment in lease | 24 | 27 |
| Investment in PERH | 21 | 22 |
| Portfolio investments (note 21) | 3 | 3 |
| Other | 20 | 20 |
| | $ 121 | $ 120 |

**Net investment in lease**

The PPA under which the Company's power generation facility located in Oxnard, California operates is considered to be a direct financing lease under GAAP. The PPA expires in 2020. The current portion of the net investment in lease of $2 million (2009 - $2 million) is included in accounts receivable. Financing income for the year ended December 31, 2010 of $2 million (six months ended December 31, 2009 - $1 million) is included in revenues.

**Investment in PERH**

Through the acquisition described in note 4, the Company, as part of its CPILP subsidiary, acquired 17.0% of the common share interests and 14.2% of the preferred interests in Primary Energy Recycling Holdings LLC (PERH). Effective August 24, 2009, PERH converted its outstanding preferred interests into common shares. As a result of the conversion, the Company now holds 14.3% of the outstanding common shares of PERH. Until the conversion date, the Company's common share interest in PERH was accounted for using the equity method and the preferred interest was recorded on the cost basis. Subsequent to the conversion of the preferred interests into common shares, the Company commenced recording its entire 14.3% common share interest on the cost basis. For the period from July 1 to August 24, 2009, equity losses of $1 million, included in operations, maintenance and direct administration expense, have been recorded against the common share investment in PERH. No gain or loss was recorded on the conversion.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**12. Long-term debt:**

| | Effective Interest Rate | December 31, 2010 | December 31, 2009 |
|---|---|---|---|
| **CPLP unsecured senior debt payable to EPCOR** | | | |
| Due in 2010 at 6.95% | | $ - | $ 202 |
| Due in 2011 at 6.60% | 5.53% | 202 | 204 |
| Due in 2016 at 6.75% | 6.16% | 133 | 134 |
| Due in 2018 at 5.80% | 5.63% | 165 | 165 |
| Due between 2011 and 2018 at 9.00% | 7.41% | 119 | 167 |
| Total CPLP debt payable to EPCOR | | 619 | 872 |
| Less: Current portion | | 234 | 245 |
| | | 385 | 627 |
| **CPLP debt payable to non-related parties** | | | |
| Unsecured senior medium-term notes, at 5.28%, due in 2020 | 5.31% | 300 | - |
| Non-recourse financing: | | | |
| Joffre Cogeneration Project, at fixed and floating rates, due in 2020 | 8.35% | 41 | 41 |
| Brown Lake Project, at 8.7%, due in 2016 | 7.13% | 6 | 6 |
| Revolving extendible credit facilities, at floating rates, due in 2013 | 3.10% | 217 | 100 |
| Total CPLP debt payable to non-related parties | | 564 | 147 |
| Less: Current portion | | 1 | 1 |
| | | 563 | 146 |
| **CPILP debt** | | | |
| Unsecured senior notes (US$190), at 5.90%, due in 2014 | 6.23% | 188 | 200 |
| Unsecured senior medium-term notes, at 5.95%, due in 2036 | 7.11% | 204 | 203 |
| Unsecured senior medium-term notes (US$150), at 5.87%, due in 2017 | 6.13% | 148 | 156 |
| Unsecured senior medium-term notes (US$75), at 5.97%, due in 2019 | 6.26% | 73 | 77 |
| Secured term loan, at 11.25%, due in 2010 | | - | 1 |
| Revolving extendible credit facilities, at floating rates, due in 2012 | 2.85% | 86 | 78 |
| Total CPILP debt | | 699 | 715 |
| Less: Current portion | | - | 1 |
| | | 699 | 714 |
| | | 1,647 | 1,487 |
| Less: Deferred debt issue costs | | 13 | 15 |
| | | $ 1,634 | $ 1,472 |

**12. Long-term debt, continued:**

**Unsecured senior debt payable to EPCOR**

The unsecured senior debt payable to EPCOR matures between 2011 and 2018. On or after December 2, 2012, if EPCOR no longer owns, directly or indirectly, at least 20% of the outstanding limited partnership units of CPLP, a subsidiary of Capital Power, then EPCOR may, by written notice, require repayment of all or any portion of the outstanding principal amount of this debt and accrued interest thereon.

**CPILP and CPLP unsecured senior notes**

The CPILP unsecured senior notes of $188 million (US$190 million) mature in 2014 and are fully and unconditionally guaranteed by CPILP as to payment of principal, premium, if any, and interest on a senior unsecured basis. Interest is payable semi-annually.

The CPILP unsecured senior medium-term notes of $204 million are due in 2036 with interest payable semi-annually.

The CPILP unsecured senior medium-term notes aggregating to $221 million (US$225 million) were issued in two tranches. The $148 million (US$150 million) and $73 million (US$75 million) tranches are due in 2017 and 2019 respectively with interest payable semi-annually.

The CPLP unsecured senior medium-term notes of $300 million are due in 2020 with interest payable semi-annually.

**Non-recourse financing**

Joffre Cogeneration Project financing represents the Company's share of syndicated loans for the project. A $40 million portion of the debt bears a fixed interest rate of 8.59% payable quarterly until 2020. The remaining debt bears interest at the prevailing bankers' acceptance rate plus a spread of 1.5% which escalates to 1.875% over the term of the loan. The debt is secured by a charge against project assets which have a carrying amount of $79 million. Brown Lake Project financing is secured by a charge against project assets which have a carrying amount of $11 million.

**CPILP and CPLP revolving extendible credit facilities**

Two unsecured credit facilities of $100 million and one unsecured credit facility of $125 million, for a total of $325 million, committed to 2012, and uncommitted amounts of $20 million and $20 million (US$20 million), are available to the Company's subsidiary, CPILP. At December 31, 2010, the Company had $86 million in bankers' acceptances (2009 – $74 million) and nil in U.S. LIBOR loans (2009 - $4 million (US$4 million)) outstanding under these facilities.

Unsecured three-year credit facilities of $700 million, committed to 2013 and uncommitted amounts of $20 million are available to the Company's subsidiary, CPLP. At December 31, 2010, the Company had $217 million in bankers' acceptances outstanding under this facility (2009 - $100 million). Additional uncommitted amounts of $5 million are available to the Company and are undrawn at December 31, 2010 (2009 – nil).

The Company also has unsecured credit facilities of $500 million available through its CPLP subsidiary. These facilities have a maturity date of July 9, 2013. As at December 31, 2010, no amounts have been drawn on these facilities (2009 – nil), but letters of credit of $122 million (2009 - $119 million) have been issued as described in note 31.

Under the terms of the extendible facilities, the Company may obtain advances by way of prime loans, U.S. base rate loans, U.S LIBOR loans and bankers' acceptances. Depending on the Company's credit rating, amounts drawn by way of prime or U.S. Base Rate loans bear interest at the prevailing Canadian Prime or U.S. Base Rate respectively, plus a spread ranging from 0.50% to 2.25%. Amounts drawn by way of U.S. LIBOR loans bear interest at the prevailing LIBOR rate plus a spread ranging from 1.50% to 3.25% based on the Company's credit rating. Amounts drawn by way of bankers' acceptances bear interest at the prevailing bankers' acceptance rate plus a spread based on the Company's credit rating.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**13. Other non-current liabilities:**

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Asset retirement obligations (note 14) | $ 86 | $ 81 |
| Employee future benefit liabilities (note 28) | 10 | 10 |
| Other | 23 | 18 |
| | $ 119 | $ 109 |

**14. Asset retirement obligations:**

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Balance, beginning of period | $ 89 | $ - |
| Liabilities assumed on acquisition of assets (notes 3 and 4) | 2 | 88 |
| Liabilities incurred | 6 | 3 |
| Liabilities settled | (8) | (4) |
| Asset retirement obligations accretion expense | 6 | 3 |
| Other | (1) | (1) |
| | 94 | 89 |
| Less: current portion in accounts payable and accrued liabilities | 8 | 8 |
| | $ 86 | $ 81 |

The Company estimates the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $390 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2013 and 2090. The majority of the payments to settle the obligations are expected to occur between 2023 and 2066 for the power generation plants, and between 2013 and 2018 for sections of the Genesee coal mine. Discount rates ranging from 4.1% to 8.7% were used to calculate the carrying amount of the asset retirement obligations. No assets have been legally restricted for settlement of these liabilities.

**15. Non-controlling interests:**

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

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| Non-controlling interests in CPILP | $ 24 | $ 26 |
| Non-controlling interests in CPLP | 88 | 68 |
| Preferred share dividends paid by subsidiary company | 14 | 4 |
| | $ 126 | $ 98 |

(Tabular amounts in millions of dollars, except shares and per share amounts)

**15. Non-controlling interests, continued:**

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

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Non-controlling interests in CPILP, beginning of period | $ 345 | $ - |
| Non-controlling interests in CPILP in net assets acquired (note 4) | - | 383 |
| Net income attributable to non-controlling interests | 24 | 26 |
| Other comprehensive loss attributable to non-controlling interests | (46) | (34) |
| Distributions to non-controlling interests | (68) | (33) |
| Issue of CPILP units to non-controlling interests | 27 | 3 |
| Non-controlling interests in CPILP, end of period | 282 | 345 |
| Non-controlling interests in CPLP, beginning of period | 1,481 | - |
| Non-controlling interests in CPLP in net assets acquired (note 4) | - | 130 |
| Partnership units issued to non-controlling interests (note 4) | - | 1,302 |
| Net income attributable to non-controlling interests | 88 | 68 |
| Other comprehensive income attributable to non-controlling interests | (5) | 17 |
| Distributions to non-controlling interests (note 35) | (69) | (36) |
| Exchange of CPLP units for CPC shares (note 16) | (243) | - |
| Non-controlling interests in CPLP, end of period | 1,252 | 1,481 |
| Preferred shares issued by subsidiary companies, beginning of period | 220 | - |
| Preferred shares outstanding in acquired subsidiaries (note 4) | - | 122 |
| Issue of preferred shares | - | 98 |
| Preferred shares issued by subsidiary companies, end of period | 220 | 220 |
| | $ 1,754 | $ 2,046 |

The non-controlling interests in CPILP represent the approximate 70.4% interest (December 31, 2009 – 69.5%) in CPILP not owned by CPLP. The non-controlling interests in CPLP represent the approximate 60.5% interest (December 31, 2009 – 72.25%) in CPLP not owned by the Company which includes approximately 60.5% of CPLP's approximate 29.6% interest in CPILP.

In November 2009, a subsidiary of CPILP issued 4 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the Series 2 Shares) priced at $25.00 per share for proceeds of $100 million, less issue costs of $3 million, which was used to repay amounts outstanding under revolving credit facilities. Future income tax assets of $1 million related to the share issue costs are recorded in the preferred share balance. The Series 2 Shares pay fixed cumulative dividends of $1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The Series 2 Shares are redeemable at $25.00 per share by CPILP on December 31, 2014 and on December 31 every five years thereafter. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the Series 3 Shares) of CPILP, subject to certain conditions, on December 31, 2014 and every five years thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of CPILP, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 4.18%.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**15. Non-controlling interests, continued:**

**Preferred shares issued by subsidiary**

A subsidiary of CPILP has issued 5 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 priced at $25.00 per share with dividends payable on a quarterly basis at the annual rate of $1.2125 per share. On or after June 30, 2012, the shares are redeemable by the subsidiary company at $26.00 per share, declining by $0.25 each year to $25.00 per share after June 30, 2016. The shares are not retractable by the holders. Under the terms of the preferred share issue, CPILP will not make any distributions on partnership units if the declaration or payment of dividends on the preferred shares is in arrears. Dividends will not be paid on the preferred shares if the senior unsecured notes of CPILP are in default.

**16. Share capital:**

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

| | December 31, 2010 | | December 31, 2009 | |
|---|---|---|---|---|
| | Issued | Outstanding | Issued | Outstanding |
| Common shares | 30,980,500 | $ 698 | 21,750,000 | $ 477 |
| Preferred shares, series 1 | 5,000,000 | 122 | - | - |
| Special voting shares | 47,416,000 | - | 56,625,000 | - |
| Special limited voting share | 1 | - | 1 | - |
| | | $ 820 | | $ 477 |

In December 2010, a subsidiary of EPCOR exchanged 9,209,000 of their exchangeable limited partnership units in CPLP on a one-for-one basis for common shares of Capital Power and subsequently entered into an agreement for a secondary offering of 9,209,000 common shares of Capital Power at an offering price of $24.00 per common share. This transaction has reduced EPCOR's ownership interest in CPLP to approximately 60.5% from their initial ownership interest of 72.2%.

The initial $500 million of common shares issued to the public in 2009 are recorded net of share issue costs of $32 million as described in note 4. Future income taxes of $9 million related to the share issue costs have been recorded as an increase to common shares.

In December 2010, the Company issued 5 million Cumulative Rate Reset Preferred Shares, series 1 (Series 1 Shares), priced at $25.00 per share for gross proceeds of $125 million, less issue costs of $4 million which have been loaned to the Company's CPLP subsidiary to repay a portion of the outstanding balance under its credit facilities which were used to fund the acquisition of Island Generation (note 3). Future income tax assets of $1 million related to the share issue costs are recorded in the preferred share balance. The preferred shares will pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the board of directors of Capital Power, for the initial five-year period ending December 31, 2015. The dividend rate will be reset on December 31, 2015 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%. The Series 1 Shares are redeemable by Capital Power, at its option, on December 31, 2015 and on December 31 of every fifth year thereafter.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**16. Share capital, continued:**

Holders of Series 1 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 2 (the "Series 2 Shares"), subject to certain conditions, on December 31, 2015 and on December 31 of every fifth year thereafter. Holders of Series 2 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.17%, as and when declared by the board of directors of Capital Power.

The special voting shares and special limited voting shares were issued to a related party, EPCOR (including subsidiaries of EPCOR). The special limited voting share entitles the holder the right to vote as a class on any matter that would: (i) change the location of Capital Power's head office to a place other than The City of Edmonton in the Province of Alberta; (ii) amend the articles of Capital Power to, or result in a transaction that would, in each case, impact the location of the head office or its meaning as defined in Capital Power's articles; or (iii) amend the rights attaching to the special limited voting share.

The special voting share holders are entitled to nominate and elect four Directors to the Company's Board of Directors, provided that they own not less than 20% of the aggregate number of outstanding CPC common shares and CPLP exchangeable LP units (exchangeable for CPC common shares). The special voting share holders are entitled to nominate and elect two Directors to the Company's Board of Directors, provided that they own less than 20% but not less than 10% of the aggregate number of outstanding CPC common shares and CPLP exchangeable LP units.

**Share purchase options**

Under the Company's long term incentive plan, the Company provides stock options to certain employees to purchase common shares, provided that the number of shares reserved for issuance will not exceed 10% of the common shares to be outstanding at closing and that the aggregate number of shares issued by the Corporation under this Plan will not exceed 5,000,000 common shares. The exercise price of the options is determined by the Corporation and shall not be less then the market price of the Corporation's shares on the date of the grant of the option.

In July 2009 the Company granted 2,183,100 share purchase options with one third vesting on January 1 of each of 2010, 2011, and 2012. The fair value of these options at grant date was $2.57 per option. Granted options may be exercised within 7 years of the grant date at a price of $23.00 per share.

During the year ended December 31, 2010, the Company granted 1,246,046 share purchase options with one third vesting on March 9 of each of 2011, 2012 and 2013. The fair value of these options at grant date was $2.37 per option. Granted options may be exercised within 7 years of the grant date at a price of $22.50 per share.

The following assumptions were used in estimating the fair value of the granted share purchase options:

| Variable | Value |
|---|---|
| Expected life | Seven-year term |
| Forfeiture rate | 2.0% to 4.0% |
| Risk free interest rate | Based on Government of Canada zero-coupon yield curve at July 2, 2009 and March 1, 2010 respectively |
| Volatility | 20% (estimated based on similar publicly-traded companies) |
| Dividend yield | 5.5% to 5.6% |

(Tabular amounts in millions of dollars, except shares and per share amounts)

**16. Share capital, continued:**

**Share purchase options, continued**

The following illustrates the movements on share purchase options during the period ended December 31, 2010:

| Grant Date | Expiry Date | Exercise Price | December 31, 2009 | Granted | Exercised | Forfeited | December 31, 2010 |
|---|---|---|---|---|---|---|---|
| July 1, 2009 | July 18, 2016 | $ 23.00 | 2,183,100 | - | 21,500 [1] | 261,200 | 1,900,400 |
| March 8, 2010 | March 9, 2017 | $ 22.50 | - | 1,246,046 | - | 52,553 | 1,193,493 |

[1] The weighted average share price at the date of exercise was $23.27.

During the year, the Company recorded compensation expenses of $2 million related to share purchase options in indirect administration (six months ended December 31, 2009 - $2 million).

At December 31, 2010, 633,467 of the share purchase options were vested (December 31, 2009 – nil).

The weighted average remaining contractual life of the Company's outstanding share purchase options at December 31, 2010 is 5.8 years.

**Performance Share Units**

On March 9, 2010, Capital Power Corporation granted performance share units (PSUs) to certain employees, which entitles those employees to receive payments based on an equivalent number of common shares at a specified release date or an amount equal to the market price of such number of common shares on the release date. PSUs have a three-year vesting period from the grant date. Upon vesting, participants receive payments based on the number of units that vest including dividend equivalents with an ending value based on the prevailing market price at vesting. PSUs will be paid in cash based on the Company's share performance relative to a group of peer organizations ranging from 50 percent to 150 percent times the market price of the PSU at the release date.

| | December 31, 2010 Outstanding PSUs |
|---|---|
| Granted | 152,801 |
| Dividends reinvested | 6,321 |
| Forfeited | (5,882) |
| Outstanding end of year | 153,240 |

During the year, the Company recorded compensation expenses of $1 million related to the outstanding PSUs in indirect administration.

At December 31, 2010, none of the Company's outstanding PSUs were vested.

**Deferred Stock Units**

The Company has approved a deferred stock unit (DSU) plan pursuant to which non-employee directors of the Company may receive their annual equity retainer in the form of DSUs. Directors are entitled to elect to receive their annual retainer, committee retainer, and/or committee chair retainer in full or partial DSUs. Directors will receive additional DSUs in respect of dividends payable on common shares of the Company based on the value of a DSU at that time. During the year, the Company recorded compensation expenses of $1 million related to the outstanding DSUs in indirect administration.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**16. Share capital, continued:**

**Earnings per share**

| | Year ended December 31, 2010 | | Six months ended December 31, 2009 | |
|---|---|---|---|---|
| | Common shares | Net income | Common shares | Net income |
| Amounts used in calculation of basic earnings per share | 22,188,266 | $ 11 | 21,750,000 | $ 21 |
| Effect of dilutive share purchase options [1] | - | - | - | - |
| Effect of exchangeable limited partnership units [2] | - | - | 56,625,000 | 49 |
| Amounts used in calculation of diluted earnings per share | 22,188,266 | $ 11 | 78,375,000 | $ 70 |

[1] For the year ended December 31, 2010 and six months ended December 31, 2009, the share purchase options did not have a dilutive effect on earnings per share as the average market price of the Company's common shares was below the exercise price.

[2] The exchangeable limited partnership units issued to EPCOR may be exchanged for common shares of Capital Power on a one-for-one basis. For the year ended December 31, 2010 the potential exchange of such units for common shares of the Company were not included in the calculation of diluted earnings per share as they were anti-dilutive. For the six months ended December 31, 2009, the potential exchange of such units for common shares of the Company had a dilutive impact as the potential exchange would remove the attribution of net income to non-controlling interests related to CPLP of $68 million. Additionally, the income tax provision of the Company would need to be adjusted to reflect the non-controlling interest's share of CPLP income taxes of $ 19 million.

**17. Accumulated other comprehensive income:**

The components of accumulated other comprehensive income are as follows:

| | December 31, 2010 | December 31, 2009 (notes 2(b) and 35) |
|---|---|---|
| Unrealized gains on derivative instruments designated as cash flow hedges[1] | $ 1 | $ 29 |
| Unrealized loss in self-sustaining foreign operations[2] | (72) | (43) |
| Accumulated other comprehensive loss | (71) | (14) |
| | | |
| Attributable to: | | |
| Non-controlling interests[3] | (68) | (17) |
| Common shareholders | $ (3) | $ 3 |

[1] Net of income tax recoveries of $17 million at December 31, 2010, and net of income tax expenses of $1 million at December 31, 2009.

[2] Net of income tax expenses of $1 million at December 31, 2010, and net of income tax expenses of nil at December 31, 2009.

[3] Net of income tax expenses of nil at December 31, 2010 and 2009.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**18. Change in non-cash working capital:**

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| Operating activities: | | |
| Accounts receivable | $ 14 | $ (61) |
| Income taxes recoverable | 19 | - |
| Inventories | (14) | (9) |
| Prepaid expenses | 1 | 2 |
| Accounts payable and accrued liabilities | (6) | 65 |
| Other current liabilities | 2 | 5 |
| | 16 | 2 |
| Investing activities: | | |
| Accounts payable | $ (28) | $ 3 |

**19. Net financing expenses:**

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| Interest on long-term debt | $ 104 | $ 53 |
| Capitalized interest | (44) | (20) |
| Unrealized losses on interest rate swaps (note 22) | 6 | - |
| Other | 8 | 1 |
| | $ 74 | $ 34 |

**20. Income taxes:**

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| Current income taxes | $ 10 | $ 1 |
| Future income taxes | (2) | 9 |
| | $ 8 | $ 10 |

(Tabular amounts in millions of dollars, except shares and per share amounts)

**20. Income taxes, continued:**

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

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| Income before income tax expense | $ 145 | $ 129 |
| Statutory income tax rates | 28.0% | 29.0% |
| Income taxes at statutory rate | 41 | 37 |
| Increase (decrease) resulting from: | | |
| Amounts previously not recognized on investment in subsidiaries | 11 | - |
| Taxable income attributable to non-controlling interests | (33) | (23) |
| Prior period tax adjustments | 4 | - |
| Change in valuation allowance | - | (2) |
| Non-taxable amounts | (11) | (2) |
| Adjustment for enacted changes in income tax laws and rates and other tax rate differences | - | (2) |
| Other | (4) | 2 |
| | $ 8 | $ 10 |

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:

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Property, plant and equipment – differences in net book value and tax bases | $ (129) | $ (102) |
| Losses carried forward | 96 | 79 |
| Power purchase arrangements | (22) | (27) |
| Deferred income from partnerships | (8) | (19) |
| Asset retirement obligations | 17 | 13 |
| Cumulative eligible capital | 17 | 12 |
| Derivative instruments | 15 | (5) |
| Contract rights | (15) | (14) |
| Investment in subsidiary | (15) | - |
| Other | (2) | 10 |
| Net future income tax liabilities | $ (46) | $ (53) |
| **Presented on the balance sheet as follows:** | | |
| Current assets | $ 7 | $ 2 |
| Non-current assets | 63 | 61 |
| Current liabilities | (21) | (21) |
| Non-current liabilities | (95) | (95) |
| | $ (46) | $ (53) |

(Tabular amounts in millions of dollars, except shares and per share amounts)

**20. Income taxes, continued:**

At December 31, 2010, the Company has non-capital losses carried forward of approximately $316 million (2009 - $263 million), of which $163 million (2009 - $155 million) relate to certain U.S. subsidiaries. These losses expire between 2026 and 2030. The Company also has capital losses for income tax purposes of approximately $19 million (2009 - $5 million). There are non-capital losses available to be carried forward of $18 million (2009 - $22 million), capital losses available to be carried forward of $5 million (2009 - $5 million) and other deductible temporary differences of $198 million (2009 - $248 million) for which no tax benefit has been recognized.

**Income Tax Recognition**

As a result of the Reorganization (as described in note 4), Capital Power holds an economic interest in CPLP of 39.5% (2009 - 27.8%). Accordingly, the Company recognizes current and future income tax assets and liabilities related to its economic interest in CPLP.

**21. Fair value and classification of non-derivative financial assets and liabilities:**

The Company classifies its cash and cash equivalents as held for trading and measures them at fair value. Accounts receivable are classified as loans and receivables; accounts payable and accrued liabilities are classified as other financial liabilities; all of which are measured at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature.

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

| | | December 31, 2010 | | December 31, 2009 | |
|---|---|---|---|---|---|
| Financial asset or liability | Classification | Carrying amount | Fair value | Carrying amount | Fair value |
| **Other assets** | | | | | |
| Loans and other long-term receivables | Loans and receivables | $ 53 | $ 52 | $ 48 | $ 46 |
| Net investment in lease | Loans and receivables | 24 | 25 | 27 | 27 |
| **Long-term debt** (including current portion) | Other financial liabilities | 1,869 | 1,920 | 1,719 | 1,724 |

**Net investment in lease**

The fair value of the Company's net investment in lease is based on the estimated interest rates implicit in comparable lease arrangements or loans plus an estimated credit spread based on the counterparty risk as at December 31, 2010 and 2009.

**Long-term debt**

The fair value of the Company's long-term debt is based on determining a current yield for the Company's debt as at December 31, 2010 and 2009. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Company's debt. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

**Other financial instruments**

Fair values on the remaining financial instruments are determined by reference to quoted bid or ask prices, as appropriate, in active markets at period-end dates.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**21. Fair value and classification of non-derivative financial assets and liabilities, continued:**

**Other financial instruments, continued**

The fair value of certain capital venture investments and the Company's investment in PERH cannot be measured reliably as the shares are not quoted in an active market and are therefore classified as available for sale. The carrying values, less impairments, recognized on these investments are disclosed in note 11. During the six months ended December 31, 2009, the recoverable amount of one of the Company's capital venture investments declined below its carrying amount, and the Company determined that the decline was other than temporary. The Company's assessment of the decline as other than temporary was consistent with the factors considered by the venture investment's Fund Manager. The carrying amount of the investment was reduced to its estimated fair value, and the Company recognized an impairment loss of $4 million in indirect administration expense for the six months ended December 31, 2009. Such impairment losses are not reversed in subsequent periods. No similar impairments have been recorded for the year ended December 31, 2010. Investments in common shares held at their carrying amount have not been offered for sale and in the event the Company elected to dispose of the shares, they would most likely be sold in a private transaction.

**22. 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 as described in note 24 consist of the following:

| | December 31, 2010 | | | | |
|---|---|---|---|---|---|
| | Energy | | Foreign exchange | Interest rate | |
| | Cash flow hedges | Non-hedges | Non-hedges | Non-hedges | Total |
| Derivative instruments assets: | | | | | |
| Current | $ 28 | $ 113 | $ 11 | $ - | $ 152 |
| Non-current | 16 | 30 | 30 | - | 76 |
| Derivative instruments liabilities: | | | | | |
| Current | (24) | (93) | (3) | (6) | (126) |
| Non-current | (77) | (13) | (5) | - | (95) |
| Net fair value | $ (57) | $ 37 | $ 33 | $ (6) | $ 7 |
| Net notional buys (sells): | | | | | |
| Megawatt hours of electricity (millions) | (3) | (2) | | | |
| Gigajoules of natural gas (millions) | 38 | 6 | | | |
| Foreign currency (U.S. dollars) | | | $ (302) | | |
| Interest rate swaps | | | | $ 200 | |
| Range of contract terms in years | 0.1 to 6.0 | 0.1 to 7.0 | 0.1 to 5.5 | 0.2 | |

(Tabular amounts in millions of dollars, except shares and per share amounts)

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

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

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

(Tabular amounts in millions of dollars, except shares and per share amounts)

**22. 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:

| | Year ended December 31, 2010 | | Six months ended December 31, 2009 | |
|---|---|---|---|---|
| | Unrealized gains (losses) | Realized gains (losses) | Unrealized gains (losses) | Realized gains (losses) |
| Energy cash flow hedges | $ (46) | $ (9) | $ 30 | $ (34) |
| Energy non-hedges | (38) | 21 | 18 | 2 |
| Foreign exchange non-hedges | 8 | 4 | 41 | (2) |
| Interest rate non-hedges | (6) | - | - | - |

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.

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

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 year ended December 31, 2010, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was $2 million (six months ended December 31, 2009 – nil). Net gains of $9 million, net of income tax recoveries 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.

**23. Fair value hierarchy:**

Fair value represents the Company's estimate of the price at which a financial instrument could be exchanged between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated balance sheet are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs and precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs. The determination of fair value requires judgment and is based on market information where available and appropriate. The following levels were established for each input:

- Level 1: Fair value is based on quoted prices (unadjusted) in active markets for identical instruments. Financial instruments classified in Level 1 include cash and cash equivalents, highly liquid short-term investments, and traded commodities obtained from active exchanges such as the New York Mercantile Exchange (NYMEX) whereby the Company can obtain quoted prices for identically traded commodities.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**23. Fair value hierarchy, continued:**

- Level 2: Fair value is based on other than unadjusted quoted prices included in level 1, which are either directly or indirectly observable at the reporting date. Level 2 includes those financial instruments that are valued using commonly used valuation techniques, such as the discounted cash flow model or the Black-Scholes option pricing model. Valuation models use inputs such as quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active but observable, and other observable inputs that are principally derived from or corroborated by observable market data for substantially the full term of the instrument. Financial instruments classified in Level 2 include commodity and foreign exchange derivatives whose values are determined based on broker quotes, observable trading activity for similar, but not identical instruments, and prices published on information platforms and exchanges.
- Level 3: Fair value is based on unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the instrument. Level 3 includes financial instruments that are also valued using commonly used valuation techniques described in Level 2, however some inputs used in the models may not be based on observable market data, but rather are based on the Company's best estimate from the perspective of a market participant. Financial instruments classified in Level 3 include long-dated commodity derivatives, commodity contracts involving non-standard features, transmission and commodity based options, and credit derivatives whose values are in part determined based on historical data such as plant operation costs, credit default probabilities, transmission congestion, demand profiles, volatilities and correlations between products derived from historical prices.

The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment which will affect the placement within the fair value hierarchy levels. The following table presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated balance sheet, classified using the fair value hierarchy described above:

| | December 31, 2010 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Financial assets and liabilities: | | | | |
| Cash | $ 56 | $ - | $ - | $ 56 |
| Derivative instrument assets | | | | |
| Commodity derivatives | - | 171 | 16 | 187 |
| Foreign exchange derivatives | - | 41 | - | 41 |
| | $ - | $ 212 | $ 16 | $ 228 |
| Derivative instrument liabilities | | | | |
| Commodity derivatives | (3) | (199) | (5) | (207) |
| Foreign exchange derivatives | - | (8) | - | (8) |
| Interest rate derivatives | - | (6) | - | (6) |
| | $ (3) | $ (213) | $ (5) | $ (221) |

(Tabular amounts in millions of dollars, except shares and per share amounts)

**23. Fair value hierarchy, continued:**

| | December 31, 2009 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Financial assets and liabilities: | | | | |
| Cash | $ 52 | $ - | $ - | $ 52 |
| Derivative instrument assets | | | | |
| Commodity derivatives | 4 | 252 | 14 | 270 |
| Foreign exchange derivatives | - | 31 | - | 31 |
| | $ 4 | $ 283 | $ 14 | $ 301 |
| Derivative instrument liabilities | | | | |
| Commodity derivatives | (6) | (187) | (11) | (204) |
| Foreign exchange derivatives | - | (6) | - | (6) |
| | $ (6) | $ (193) | $ (11) | $ (210) |

There were no significant transfers between Level 1 and 2 for the year ended December 31, 2010 or for the six months ended December 31, 2009.

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

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Balance, beginning of period | $ 3 | $ - |
| Acquired from EPCOR [1] | - | 2 |
| Unrealized and realized gains included in net income [2] | 12 | 3 |
| Purchases | (3) | - |
| Settlements[3] | (1) | (2) |
| Balance, end of period | 11 | 3 |
| Total unrealized gains for the period included in net income | $ 9 | $ 1 |

[1] The fair value of derivative instruments is presented on a net basis.
[2] Gains and losses are recorded in energy revenues or energy purchases and fuel, as appropriate.
[3] Relates to settlement of financial derivative instruments.

All instruments classified as level 3 are derivative type instruments, which include financial and non-financial commodity contracts, financial commodity and transmission options, and credit derivatives. Gains and losses associated with Level 3 balances may not necessarily reflect the underlying exposures of the Company. As a result, unrealized gains and losses from Level 3 financial instruments are often offset by unrealized gains and losses on financial instruments that are classified in Levels 1 or 2.

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

**24. Risk management:**

**Risk management overview**

The Company is exposed to a number of different financial risks, arising from business activities and its use of financial instruments, including market risk, credit risk, and liquidity risk. The Company's overall risk management process is designed to identify, manage and mitigate business risk which includes, among other risks, financial risk. Risk management is overseen by the Company's executive team according to objectives, targets, and policies approved by the Capital Power Board of Directors. The executive team is comprised of a senior management group.

Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the Company's business objectives and risk tolerance. The Company's financial risk management objective is to protect and limit the volatility in earnings and cash flow.

Commodity price risk management and the associated credit risk management are carried out in accordance with the respective commodity, credit, and financial exposures risk management policies, as approved by the executive team and the Board of Directors. Financial risk management including foreign exchange risk, interest rate risk, liquidity risk, and the associated credit risk management, is carried out by a centralized Treasury function, also in accordance with a financial risk management policy approved by the executive team and the Board. Capital Power's Audit Committee of the Board of Directors, in its oversight role, monitors the assessment of risk management controls and procedures to ensure compliance with applicable policies.

**Market risk**

Market risk is the risk of loss that results from changes in market factors such as commodity prices, foreign currency exchange rates, interest rates, and equity prices. The level of market risk to which the Company is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Company's financial assets and liabilities held, non-trading physical asset and contract portfolios, and trading portfolios.

To manage the exposure related to changes in market risk, the Company uses various risk management techniques including derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps (or contracts-for-differences), and option contracts. Such derivative instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. Commodity market risk exposures are monitored daily against approved risk limits, and control processes are in place to monitor that only authorized activities are undertaken.

The sensitivities provided in each of the following risk discussions disclose the effect of reasonably possible changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of earnings on these contracts. The Company's actual exposure to market risks is constantly changing as the Company's portfolio of debt, foreign currency and commodity contracts changes. Changes in fair values or cash flows based on market variable fluctuations cannot be extrapolated since the relationship between the change in the market variable and the change in fair value or cash flows may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Company.

**24. Risk management, continued:**

**Market risk, continued**

*Commodity price risk*

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

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

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

The fair value of the Company's energy related derivatives at December 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 22.

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. Capital Power's current period VaR uses a statistical confidence interval of 99% over a five business 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.

**24. Risk management, continued:**

**Market risk, continued**

*Commodity price risk, continued*

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 predictor 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 approved the methodology for the ongoing determination of Commodity Risk limits, under their commodity 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 December 31, 2010, there is a 99% probability that unfavorable daily market variations would not reduce the trading portfolio by more than $6 million.

*Foreign exchange risk*

The Company is exposed to foreign exchange risk on foreign currency denominated forecasted transactions, firm commitments, and monetary assets and liabilities denominated in a foreign currency and on its net investments in foreign operations. The Company's operations expose it to foreign exchange risk arising from transactions denominated in foreign currencies. The Company's foreign exchange risk arises primarily with respect to the U.S. dollar but it is potentially exposed to changes in other currencies if and when it transacts in other currencies. The risk is that the functional currency value of cash flows will vary as a result of the movements in exchange rates.

The Company's foreign exchange management policy is to limit economic and material transactional exposures arising from movements in the Canadian dollar relative to the U.S. dollar or other foreign currencies. The Company's exposure to foreign exchange risk arises from future anticipated cash flows from its U.S. operations, debt service obligations on U.S. dollar borrowings, and from certain capital expenditure commitments denominated in U.S. dollars or other foreign currencies. The Company co-ordinates and manages foreign exchange risk centrally, by identifying opportunities for naturally-occurring opposite movements and then dealing with any material residual foreign exchange risks; these are hereinafter referred to as being economically hedged.

**24. Risk management, continued:**

**Market risk, continued**

*Foreign exchange risk, continued*

The Company primarily uses foreign currency forward contracts to fix the functional currency of its non-functional currency cash flows thereby reducing its anticipated U.S. dollar denominated transactional exposure. The Company looks to limit foreign currency exposures as a percentage of estimated future cash flows. The percentage amount to be fixed will generally be higher, the shorter the period into the future that the cash flows relate to. At December 31, 2010, US$309 million or approximately 96% of expected future net cash flows from CPILP's U.S. plants had been economically hedged for 2011 to 2016 at a weighted average exchange rate of $1.13 per U.S. dollar. At December 31, 2010, the Company has transactional exposure for US$7 million or approximately 97% of expected future net cash flows for capital expenditure commitments, which have been economically hedged for 2011 at a weighted average exchange rate of $1.07 per U.S. dollar.

As at December 31, 2010, holding all other variables constant, a $0.10 strengthening or weakening of the Canadian dollar against the U.S. dollar would increase or decrease net income attributable to common shareholders by approximately $2 million after tax. There would be no impact to other comprehensive income.

This sensitivity analysis excludes translation risk associated with the application of the current rate and temporal rate translation methods, financial instruments that are non-monetary items, and financial instruments denominated in the functional currency in which they are transacted and measured.

*Interest rate risk*

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating rate short-term and long-term loans and obligations. The Company is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. At December 31, 2010, the proportion of fixed rate debt was approximately 84% of total long-term debt outstanding (2009 – 90%). The Company may also use derivative instruments to manage interest rate risk. At December 31, 2010, the Company held interest rate derivative instruments as disclosed in note 22.

Assuming that the amount and mix of fixed and floating rate loans and net debt remains unchanged from that held at December 31, 2010, a 100 basis point decrease or increase to interest rates would decrease or increase full year net income attributable to common shareholders by $3 million and would have no direct impact on other comprehensive income.

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

**Credit risk**

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Company. The Company's counterparty credit risk management policy is established by the executive team and approved by the Board of Directors and the associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the Company. Credit risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into any agreements or transactions with the counterparty. Credit exposures and concentrations are subsequently monitored and are regularly reported to stakeholders on an ongoing basis. Counterparty creditworthiness also continues to be evaluated on an ongoing basis after transactions have been initiated.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**24. Risk management, continued:**

**Credit risk, continued**

Credit risk is managed and mitigated through a number of risk mitigation practices such as securing parent company guarantees to enhance counterparty credit quality, negotiating and obtaining security (such as cash, letters of credit or property) to offset potential losses, utilization of credit derivatives to reduce credit risk, and margining to limit credit risk where applicable.

*Maximum credit risk exposure*

The Company's maximum credit exposure was represented by the carrying amount of the following financial assets:

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Cash and cash equivalents | $ 56 | $ 52 |
| Accounts receivable [1] | 271 | 275 |
| Derivative instruments assets [1] | 228 | 301 |
| Loans and other long-term receivables | 53 | 48 |
| Net investments in leases | 24 | 27 |
| Loan commitments to third parties (note 30(f)) | 6 | 6 |
| | $ 638 | $ 709 |

[1] The Company's maximum credit exposures related to accounts receivable and derivative instruments assets by major credit concentration are comprised of maximum exposures of $162 million for generation and $337million for wholesale at December 31, 2010 and $173 million for generation and $403 million for wholesale at December 31, 2009.

This table does not take into account collateral held. At December 31, 2010, the Company held cash deposits of $4 million (2009 - $3 million) as security for certain counterparty accounts receivable and derivative contracts. The Company is not permitted to sell or re-pledge this collateral in the absence of default of the counterparties providing the collateral. At December 31, 2010, the Company also held other forms of credit enhancement in the form of letters of credit of $25 million (2009 - $29 million), property registrations valued at $74 million (2009 - $125 million) and parental guarantees of $825 million (2009 - $733 million) related to the financial assets noted above. At December 31, 2010 and December 31, 2009 the Company also held parental guarantees which do not have a defined limit, but which provide full support on any outstanding positions related to certain development projects and counterparty performance for power purchase arrangements.

*Credit quality and concentrations*

The Company is exposed to credit risk on outstanding accounts receivable associated with its generation and optimization activities including power purchase arrangements, agreements with independent system operators, power and steam sales contracts, energy supply agreements with government sponsored entities, wholesale customers, and trading counterparties. The Company is also exposed to credit risk related to its cash and cash equivalents (which include short-term investments), derivative instruments assets, and long-term financing arrangements.

**24. Risk management, continued:**

**Credit risk, continued**

*Credit quality and concentrations, continued*

The credit quality and concentrations of the Company's financial assets, by major credit concentrations are the following:

*Cash and cash equivalents*

The Company has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, are the primary counterparty of the Company's foreign exchange derivative instruments, and provide letters of credit to mitigate the Company's exposure to certain counterparties. The Company manages its credit risk on cash and cash equivalents, and short-term investments by dealing with investment grade rated banks and financial institutions and reviewing each investment vehicle to ensure underlying credit risk is known.

*Loans and long-term financing*

At December 31, 2010, loans and long-term financing consists primarily of notes receivable attributable to two Alberta PPA syndicate members. The Company is exposed to credit risk in the event of non-performance by the syndicate members, but does not anticipate such non-performance. Although the syndicate members are not investment grade, the notes receivable are secured by security interests in the syndicate members' respective shares of the power syndicate agreement.

*Accounts receivable and financial derivative instruments*

Accounts receivable is substantially made up of receivables related to the generation and sale of electricity to customers including industrial and commercial customers, independent system operators from various regions and government-owned or sponsored entities, and the settlement of financial derivative instruments related to merchant price risk mitigation and trading activities. The Company manages its credit risk on these financial assets through its credit adjudication process, dealing with creditworthy counterparties and utilizing the credit risk mitigation practices noted above.

*Generation credit risk*

Credit risk exposure from PPAs, agreements with independent system operators, power and steam sales contracts, and certain energy supply agreements is predominantly restricted to accounts receivable and contract default. In certain cases, the Company relies on a single or small number of customers to purchase all or a significant portion of a facility's output. The failure of any one of these counterparties to fulfill its contractual obligations could negatively impact the Company's financial results. Financial loss resulting from events of default by counterparties in certain PPAs and steam purchase agreements may not be recovered since the contracts may not be replaceable on similar terms under current market conditions. Consequently, the Company's financial performance depends on the continued performance by customers and suppliers of their obligations under these long-term agreements. Credit risk exposure is mitigated by dealing with creditworthy counterparties that are determined to be investment grade based on the Company's internally assigned ratings or employing mitigation strategies as noted above, netting amounts by legally enforceable set-off rights, and, when appropriate, taking back security from the counterparty. Credit risk with counterparties in this asset class that are government-owned or sponsored entities and regulated public utility distributors is generally considered low.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**24. Risk management, continued:**

**Credit risk, continued**

*Wholesale and merchant credit risk*

Credit risk exposure for wholesale and merchant trading counterparties is measured by calculating the costs (or proceeds) of replacing the commodity position (physical and derivative contracts), adjusting for settlement amounts due to or due from the counterparty and, if permitted, netting amounts by legally enforceable set-off rights. Financial loss on wholesale contracts could include, but is not limited to, the cost of replacing the obligation, amounts owing from the counterparty or any loss incurred on liability settlements. Wholesale and merchant credit risk exposure is mitigated by trading with investment grade and creditworthy counterparties, portfolio diversification, monitoring of credit exposure and limits, margining to reduce energy trading risks, obtaining parent company guarantees, and when appropriate taking back security from counterparties.

*Accounts receivable and allowance for doubtful accounts*

Accounts receivable consist primarily of amounts due from customers including industrial and commercial customers, independent system operators from various regions, government-owned or sponsored entities, and other counterparties. Larger commercial and industrial customer contracts and contracts-for-differences provide for performance assurances including letters of credit if deemed appropriate. The Company also has credit exposures to large suppliers of electricity and natural gas. The Company mitigates these exposures by dealing with creditworthy counterparties and, when appropriate, taking back appropriate security from the supplier.

The aging of accounts receivable was:

| | December 31, 2010 | | |
|---|---|---|---|
| | Gross accounts receivable | Allowance for doubtful accounts | Net accounts receivable |
| Current[1] | $ 270 | $ - | $ 270 |
| Outstanding greater than 90 days | 2 | 1 | 1 |
| | $ 272 | $ 1 | $ 271 |

[1] Current amounts represent accounts receivable outstanding zero to 30 days. Amounts outstanding more than 30 days are considered past due.

The changes in the allowance for doubtful accounts were as follows:

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Balance, beginning of period | $ 3 | $ - |
| Assumed allowances from acquisition of assets (note 4) | | |
| Current receivables | - | 2 |
| Long-term receivables recorded against long-term receivable balance in other assets | - | 2 |
| Settlements received on allowances | - | (1) |
| Recovery of receivables | (2) | - |
| Balance, end of period | $ 1 | $ 3 |

## 24. Risk management, continued:

### Credit risk, continued

*Accounts receivable and allowance for doubtful accounts, continued:*

At December 31, 2010, the Company held $4 million of customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers.

At December 31, 2010, there was no provision for credit losses associated with accounts receivable from treasury, trading and energy procurement counterparties as all balances are considered to be fully collectable.

### Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's liquidity is managed centrally by the Treasury function. The Company manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and also by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are addressed through a combination of committed and demand revolving credit facilities, financings in public capital and debt markets and equity offerings by the Company or its CPLP or CPILP subsidiaries.

CPC has a long-term debt rating of BBB, assigned by Standard & Poor's (S&P) and a preferred share rating of P-3(high) and Pfd-3(low) assigned by S&P and DBRS Limited (DBRS) respectively. CPLP has a long-term debt rating of BBB/stable outlook, assigned by both S&P and DBRS. CPILP has a long-term debt rating of BBB/stable outlook and BBB(high)/under review (negative), assigned by S&P and DBRS respectively.

As at December 31, 2010, the Company had undrawn and committed bank credit facilities and operating lines of credit and demand facilities, totaling $1,165 million (2009 - $1,294 million), of which $862 million (2009 - $600 million) is committed for at least two years.

In addition to the facilities noted above, the Company has shelf prospectuses under which it may raise funds in the form of debt or capital. In the third quarter of 2010, the Company's subsidiary, CPILP, issued a Canadian shelf prospectus, which expires in August 2012, under which it may raise up to $600 million in partnership units, debt securities or subscription receipts. As at December 31, 2010, CPILP has not drawn on the shelf prospectus. In the second quarter of 2010, CPC issued a Canadian shelf prospectus, which expires in May 2012, under which it may raise up to $1 billion collectively in common shares of the Company and subscription receipts exchangeable for common shares and/or other securities of the Company. As at December 31, 2010, the common shares issued on exchange of the CPLP exchangeable limited partnership units, as described in note 16 have reduced the available amounts on the shelf prospectus by $221 million. In the second quarter of 2010, the Company's subsidiary, CPLP, issued a Canadian shelf prospectus, which expires in May 2012, under which it may raise up to $1 billion in medium-term notes. As at December 31, 2010 CPLP has drawn $300 million on the shelf prospectus by way of a subordinated debenture as described in note 12. In December 2010, the Company issued $125 million of preferred shares less issue costs of $4 million, as described in note 16, under a new short form prospectus.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**24. Risk management, continued:**

**Liquidity risk, continued**

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and financial assets that generate cash inflows to meet cash outflows on financial liabilities as at December 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 | $ 235 | $ 113 | $ 237 | $ 203 | $ 15 | $ 1,081 | $ 1,884 |
| Interest payments on long-term debt | 107 | 91 | 84 | 78 | 65 | 408 | 833 |
| Accounts payable and accrued liabilities [1] | 283 | - | - | - | - | - | 283 |
| Other current liabilities | 10 | - | - | - | - | - | 10 |
| Loan commitments | 6 | - | - | - | - | - | 6 |
| **Derivative financial liabilities:** | | | | | | | |
| Net forward foreign exchange contracts | 1 | 1 | - | 5 | - | 2 | 9 |
| Net commodity contracts-for-differences | 83 | 5 | 1 | - | - | - | 89 |
| | $ 725 | $ 210 | $ 322 | $ 286 | $ 80 | $ 1,491 | $ 3,114 |

[1] Excluding accrued interest on long-term debt of $21 million.

**25. Capital management:**

The Company's primary objectives when managing capital are to safeguard the Company's ability to continue as a going concern, pay regular dividends to its shareholders, maintain a suitable credit rating, and to facilitate the acquisition or development of projects in Canada and the U.S. consistent with the growth strategy of the Company. The Company manages its capital structure in a manner consistent with the risk characteristics of the underlying assets.

The Company manages capital through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Company matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**25. Capital management, continued:**

The Company considers its capital structure to consist of short-term debt and long-term debt net of cash and cash equivalents, non-controlling interests (including preferred shares issued by subsidiary companies) and equity attributable to common shareholders. The following table represents the total capital of the Company:

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Long-term debt (including current portion) (note 12) | $ 1,869 | $ 1,719 |
| Cash and cash equivalents | (56) | (52) |
| Net debt | 1,813 | 1,667 |
| Equity attributable to common shareholders | 824 | 489 |
| Non-controlling interests (note 15) | 1,754 | 2,046 |
| Owners' equity | 2,578 | 2,535 |
| Total capital | $ 4,391 | $ 4,202 |

The Company has externally imposed requirements on its capital through its subsidiaries as disclosed below.

CPLP has the following externally imposed requirements on its capital as a result of its credit facilities and certain debt covenants:

- Maintenance of modified consolidated net tangible assets to consolidated net tangible assets ratio, as defined in the debt agreements, of not less than 0.90 to 1.0;
- Maintenance of consolidated senior debt to capitalization ratio, as defined in the debt agreements, of not more than 0.65 to 1.0;
- Limitation on debt issued by subsidiaries; and
- In the event that CPLP is assigned a rating of less than BBB- by S&P and BBB(Low) by DBRS, CPLP would also be required to maintain a ratio of earnings before interest, income taxes, depreciation and amortization to interest expense, as defined in the debt agreements, of not less than 2.5 to 1.0.

CPILP has the following externally imposed requirements on its capital:

- Maintenance of debt to total capitalization ratio, as defined in the debt agreements, of not more than 65%; and
- In the event that CPILP is assigned a rating of less than BBB+ by S&P and BBB(high) by DBRS, CPILP also would be required to maintain a ratio of earnings before interest, income taxes, depreciation and amortization to interest expense of not less than 2.5 to 1.

These capital restrictions are defined in accordance with the respective agreements.

For the year ended December 31, 2010, the Company and its subsidiaries complied with all externally imposed capital restrictions.

To manage or adjust its capital structure, the Company can issue new debt, issue common or preferred shares, redeem preferred shares, issue new CPLP or CPILP units, repay existing debt or adjust dividends paid to its shareholders.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**26. Related party balances and transactions:**

Prior to the Reorganization described in note 4, the assets and operations of the Company were a part of the EPCOR consolidated entity and certain subsidiaries of the Company were subsidiaries of EPCOR. The following summarizes the Company's related party balances and transactions with EPCOR, EPCOR's subsidiaries and EPCOR's sole shareholder, the City of Edmonton. All transactions are in the normal course of operations, and are recorded at the exchange amount, which is the consideration established and agreed to by the parties.

| | | December 31, 2010 | December 31, 2009 |
|---|---|---|---|
| **Balance sheet:** | | | |
| Accounts receivable | (a) | $ 52 | $ 63 |
| Other assets | (b) | 7 | 8 |
| Property, plant and equipment | (c) | 44 | 20 |
| Accounts payable and accrued liabilities | (d) | 16 | 13 |
| Other non-current liabilities | (e) | 3 | - |
| Long-term debt (including current portion) (note 12) | | 619 | 872 |
| Share capital (note 16) | | - | - |

| | | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|---|
| **Income statement:** | | | |
| Revenues – energy sales | (f) | 399 | 219 |
| Energy purchases and fuel | (g) | 30 | 13 |
| Operations, maintenance and direct administration | (h) | 13 | 5 |
| Net financing expenses | (i) | 7 | 10 |

(a) As at December 31, 2010, accounts receivable includes $44 million (2009 – $51 million) relating to energy sales to subsidiaries of EPCOR, $2 million (2009 – $10 million) relating to other receivables from subsidiaries of EPCOR, and $6 million (2009 - $2 million) relating to energy sales to the City of Edmonton.

(b) Contributions made to subsidiaries of EPCOR for the construction of aerial and underground transmission lines.

(c) Interest on long-term debt to EPCOR capitalized to property, plant and equipment.

(d) As at December 31, 2010, includes accrued interest on long-term debt to EPCOR of $9 million (2009 - $9 million) and the current portion of an obligation to EPCOR of $4 million (2009 – nil), for future maintenance costs associated with EPCOR's Rossdale plant through 2019.

(e) Includes the non-current portion of an obligation to EPCOR of $3 million for future maintenance costs associated with EPCOR's Rossdale plant through 2019.

(f) For the year ended December 31, 2010, includes energy sales of $370 million (six months ended December 31, 2009 - $205 million) to EPCOR and its subsidiaries and $29 million (six months ended December 31, 2009 - $14 million) to the City of Edmonton.

(g) Includes energy distribution and transmission charges from subsidiaries of EPCOR.

(h) For the year ended December 31, 2010, includes the recognition of an obligation to EPCOR for future maintenance costs associated with EPCOR's Rossdale plant of $7 million (six months ended December 31, 2009 – nil).

(i) Net financing expenses on long-term debt to EPCOR.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**26. Related party balances and transactions, continued:**

In addition to the transactions disclosed above, the Company's subsidiary CPLP has recorded total distributions of $69 million to EPCOR in the year ended December 31, 2010 (six months ended December 31, 2009 - $36 million). CPLP paid distributions of $71 million to EPCOR in the year ended December 31, 2010 (six months ended December 31, 2009 - $18 million).

**27. Joint ventures:**

The Company and the coal mine operator at the Genesee plant site each have a 50% interest in the Genesee Coal Mine Joint Venture. The joint venture partner operates the coal mine. Under agreements governing this joint venture, all coal mined is to be supplied to the Company's Genesee generation plant.

The Company holds 50% interests in the Genesee 3 Project, the Keephills 3 Project and the Taylor's Coulee Chute Hydro Project, and holds a 40% interest in the Joffre Cogeneration Project. The Company, through its CPILP subsidiary, also holds a 50.15% interest in the Frederickson power plant.

A financial summary of the Company's investments in joint ventures is as follows:

| | December 31, 2010 | December 31, 2009 |
|---|---|---|
| Current assets | $ 30 | $ 44 |
| Long-term assets | 1,245 | 1,115 |
| Current liabilities | 34 | 57 |
| Long-term liabilities | 41 | 42 |
| Revenues [1] | 57 | 30 |
| Expenses [2] | 100 | 44 |
| Net loss | (43) | (14) |
| Cash flows used in operating activities | (40) | (17) |
| Cash flows used in investing activities | (183) | (109) |
| Cash flows from financing activities | 197 | 115 |

[1] Excludes all revenues from Genesee 3, which are recorded as revenues by the Company but are not subject to the terms of the joint venture agreement.

[2] Excludes all costs of operating the Genesee Coal Mine Joint Venture which are recorded as fuel expenses by the Company.

Included in the Company's cash and cash equivalents at December 31, 2010 is its proportionate share of cash and cash equivalents which is restricted to use within joint ventures of $8 million (2009 - $17 million).

Under the terms of the Company's interests in the Fredrickson power plant, the Genesee 3 Project and the Keephills 3 Project, the Company and its respective partners have guaranteed financial and performance obligations under the joint venture agreements limited to $40 million, $50 million and $50 million respectively.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**28. Employee future benefits:**

**Multiemployer defined benefit pension plan and defined contribution pension plan**

Over 80% of the Company's employees are either members of the Local Authority Pension Plan or the Company's registered defined contribution plans. Accordingly, the majority of the Company's pension costs and obligations are accounted for as defined contribution plans.

**Defined benefit plans**

The effective date for the latest actuarial valuation of the Company's registered pension plan was July 9, 2009. Prior to the transfer of employees resulting from the acquisition described in note 4, the effective date for the latest actuarial valuation of the Company's supplemental pension plan was December 31, 2007. The effective date of the next valuation for funding purposes is no later than December 31, 2011 for the registered pension plan. The effective date of the next valuation of the supplemental pension plan is no later than December 31, 2010. The date used to measure the plan assets and the accrued benefit obligation was December 31, 2010. The supplemental pension plan is a non-contributory plan that is unfunded at December 31, 2010.

As part of the Company's acquisition of its interest in CPILP from EPCOR, employees who transferred to Capital Power on July 1, 2009, and who were previously members of EPCOR's registered pension plan, became members of the Company's registered pension plan. The plan provides pension benefits based on an employee's years of service and their highest earnings over three consecutive years of employment. Retirement pensions will be increased annually by a portion of the increase in the Consumer Price Index. Under the terms of the pension transfer agreement between EPCOR and CPC, EPCOR transferred the pension liabilities and associated assets based on an actuarial valuation. Upon receipt of the required regulatory approval, the actual transfer of assets was finalized during the year ended December 31, 2010.

**Plan benefit costs, assets and obligations:**

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| **Costs recognized:** | | |
| Service cost | $ 2 | $ 1 |
| Interest on benefit obligation | 1 | - |
| Actual return on assets | (1) | - |
| Actuarial (gains) losses | 3 | (1) |
| Difference between actuarial gain recognized and actual gain on accrued benefit obligation | (3) | 1 |
| Defined benefit plans cost | 2 | 1 |
| Defined contribution plans cost | 8 | 3 |
| Net expense | $ 10 | $ 4 |

(Tabular amounts in millions of dollars, except shares and per share amounts)

**28. Employee future benefits, continued:**

**Plan benefit costs, assets and obligations, continued:**

| | 2010 | 2009 |
|---|---|---|
| **Funded status as at December 31:** | | |
| Market value of plan assets | $ 11 | $ 9 |
| Accrued benefit obligation | (22) | (17) |
| Funded status – plan deficit | (11) | (8) |
| Amounts not yet recognized in financial statements: | | |
| Unamortized net losses | 3 | 1 |
| Accrued benefit liability recognized in financial statements | $ (8) | $ (7) |
| Expected average remaining service life in years – registered pension plan | 11 | 11 |
| Expected average remaining service life in years – supplemental pension plan | 12 | 12 |

The accrued benefit liability and other employee future benefit liabilities, totalling $10 million (2009 - $10 million), are included in other non-current liabilities. Other employee future benefit liabilities consist mainly of obligations for benefits provided to employees on long-term disability leaves.

| | 2010 | 2009 |
|---|---|---|
| **Reconciliation of accrued benefit obligation:** | | |
| Accrued benefit obligation, beginning of period | $ 17 | $ - |
| Accrued benefit obligation transferred from EPCOR | - | 17 |
| Service cost | 2 | 1 |
| Interest cost | 1 | - |
| Actual benefits paid | (1) | - |
| Actuarial (gain) loss | 3 | (1) |
| Accrued benefit obligation, end of period | $ 22 | $ 17 |

| | 2010 | 2009 |
|---|---|---|
| **Plan assets:** | | |
| Market value of assets, beginning of period | $ 9 | $ - |
| Market value of assets transferred from EPCOR | - | 9 |
| Contributions | 1 | - |
| Actual return on plan assets | 1 | - |
| Market value of plan assets, end of period | $ 11 | $ 9 |

Total cash payments for pension benefits in the year ended December 31, 2010, consisting of cash contributed by the Company to the LAPP, other defined contribution and benefit plans and cash payments directly to beneficiaries for its unfunded pension plan, were $9 million (six months ended December 31, 2009 - $4 million).

(Tabular amounts in millions of dollars, except shares and per share amounts)

**28. Employee future benefits, continued:**

**Assumptions:**

The significant actuarial assumptions adopted in measuring the corporation's accrued benefit obligations were as follows:

| | 2010 | 2009 |
|---|---|---|
| Accrued benefit obligation as at December 31 | | |
| Discount rate | 5.25% | 6.00% |
| Rate of compensation increase | 4.00% | 4.00% |

| | Year ended December 31, 2010 | Six months ended December 31, 2009 |
|---|---|---|
| Benefit cost | | |
| Discount rate | 6.00% | 5.75% |
| Rate of compensation increase | 4.00% | 4.00% |
| Expected rate of return on plan assets | 6.50% | 6.50% |

Information concerning the Company's registered pension plan's target asset allocation and actual asset allocation is as follows:

| | 2010 | | 2009 | |
|---|---|---|---|---|
| | Target asset allocation | Asset allocation | Target asset allocation | Asset allocation |
| Fixed income securities | 40% | 39% | 35% | 35% |
| Equity securities | 57% | 58% | 60% | 63% |
| Other assets | 3% | 3% | 5% | 2% |
| Total | 100% | 100% | 100% | 100% |

**29. Plants under operating leases:**

Certain power generation plants operate under PPAs that convey the right to the holder of the agreement to use the related property, plant and equipment. Consequently, these power generation plants held by subsidiaries of the Company, comprised of Manchief, Mamquam, Moresby Lake, Southport, Roxboro, Kenilworth, Greeley, Williams Lake, Genesee units 1 and 2, Miller Creek, Brown Lake, Kingsbridge and Island Generation are accounted for as assets under operating leases. As at December 31, 2010, the carrying amount of such property, plant and equipment was $1,610 million (2009 - $1,363 million), less accumulated depreciation of $89 million (2009 - $26 million). The Company's revenue pursuant to the arrangements for the year ended December 31, 2010 was $442 million (six months ended December 31, 2009 - $209 million).

(Tabular amounts in millions of dollars, except shares and per share amounts)

**30. Commitments and contingencies:**

(a) The Company and TransAlta Corporation (TransAlta) are in the process of building Keephills 3, a 495 MW supercritical coal-fired generation plant at TransAlta's Keephills site. The construction is expected to be completed in 2011. As at December 31, 2010, the Company's 50% committed share of the estimated total remaining capital cost to be incurred is $63 million. The estimated total project cost is $1.9 billion and Capital Power's share is $955 million. As part of contractual arrangements, the Company and TransAlta have indemnified each other for up to $115 million during construction in the event that either party makes payments to the turbine supplier on behalf of the other party.

(b) Under the terms of the acquired Alberta PPAs, the Company is obligated to make monthly payments for fixed and variable costs. The estimated annual total of these payments for 2011 is $88 million. It is expected that the annual payments over the remaining terms of the Alberta PPAs, as described in note 2(k), will range from $88 million to $110 million, adjusted for inflation, other than in the event of a forced outage. The actual amounts for future years may vary from estimates depending on generation volume and scheduled outages.

(c) 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 will be located in southern Ontario, and developed by a subsidiary of the Company at an expected total cost of $340 million. As at December 31, 2010 the estimated total remaining capital cost to be incurred is $317 million. Energy generated by PDNW would be sold under a 20-year contract with the third party. PDNW is expected to commence commercial operations in the fourth quarter of 2012.

(d) The Company's Quality Wind Project (Quality Wind) was selected, by a third party, for the award of an Energy Purchase Agreement (EPA). The 142 MW wind power project will be located in northeastern British Columbia, and developed by a subsidiary of the Company at an expected total cost of $455 million. As at December 31, 2010 the estimated total remaining capital cost to be incurred is $432 million. Energy generated by Quality Wind would be sold under a 25-year EPA with the third party. Quality Wind is expected to commence commercial operations in the fourth quarter of 2012.

(e) The Company has entered into a number of long-term energy purchase and transportation contracts, operating and maintenance contracts, contracts to purchase environmental credits and operating leases for premises in the normal course of operations. Some of the energy purchase and transportation contracts are measured at their fair value and recorded on the consolidated balance sheet as derivative instruments assets and liabilities as appropriate. The energy purchase and transportation contract amounts disclosed below are based on gross settlement amounts. Approximate future payments under each group of contracts are as follows:

| | Energy purchase and transportation contracts | Operating and maintenance contracts | Environmental credits | Operating leases |
|---|---|---|---|---|
| 2011 | $ 94 | $ - | $ 23 | $ 2 |
| 2012 | 68 | - | 12 | 5 |
| 2013 | 58 | 5 | 11 | 5 |
| 2014 | 60 | 5 | 5 | 5 |
| 2015 | 58 | 5 | 3 | 5 |
| Thereafter | 69 | 33 | 1 | 68 |
| | $ 407 | $ 48 | $ 55 | $ 90 |

**30. Commitments and contingencies, continued:**

(f) The Company has committed to issue non-interest bearing notes receivable to the non-Capital Power syndicate members involved in the Sundance Swap transaction entered into by Capital Power subsidiaries prior to the acquisition of subsidiaries and assets from EPCOR as disclosed in note 4. The commitment relates to funding potential income tax liabilities incurred by the non-Capital Power syndicate members in relation to the transaction. The total estimated loan commitment is $19 million, with annual payments of principal commencing from the date the commitment is called by the non-Capital Power syndicate members through to December 2012. At December 31, 2010, the Company has $13 million extended under such notes and their carrying amount of $8 million, after fair value adjustments, is included in other assets.

(g) The Company and its subsidiaries are subject to various other legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

**31. Guarantees:**

The Company has issued letters of credit for $122 million (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 acquisition of subsidiaries and assets from EPCOR disclosed in note 4, 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 December 31, 2009, EPCOR continued to have outstanding parental guarantees on behalf of Capital Power totaling $1,295 million related to subsidiaries of Capital Power. In addition to this amount, EPCOR also had outstanding parental guarantees which did not have a defined limit, but which provided full support on any outstanding positions related to power purchase arrangements of Capital Power. Under the terms of the separation agreements described in note 4, the Company has transferred over these parental guarantees from EPCOR during the year-ended December 31, 2010.

**32. Government assistance:**

During the year ended December 31, 2010, the Company completed the front-end engineering and design (FEED) work on its pre-combustion carbon capture and storage project (the Genesee Integrated Gasification Combined Cycle (IGCC) power plant). The FEED project was conducted in conjunction with the Canadian Clean Power Coalition, in partnership with the Province of Alberta and the Government of Canada. During the year ended December 31, 2010, the Company recorded no additional government assistance for this project from the Province of Alberta and the Government of Canada (six months ended December 31, 2009 - $10 million reduction to indirect administration expenses) and received contributions of $9 million (six months ended December 31, 2009 - $3 million). During the six months ended December 31, 2009, the Company acquired receivables of $2 million related to this government assistance as a part of the acquisition described in note 4 above. At December 31, 2010 the Company had no accounts receivable outstanding related to this government assistance (2009 - $9 million). As a part of the agreements with the Province of Alberta and the Government of Canada, the Company was required to submit a final report in 2010 detailing the amounts spent on the project. The project has been completed to the satisfaction of the government parties, and hence none of the recorded amounts are repayable by the Company.

(Tabular amounts in millions of dollars, except shares and per share amounts)

**32. Government assistance, continued:**

In addition to the above project, Capital Power is partnering with unrelated third parties to develop a carbon capture and storage (CCS) project, Project Pioneer (Pioneer). In October 2009, a letter of intent was signed with the Province of Alberta under which Pioneer will be eligible to receive funding from the province's $2,000 million CCS fund. The Government of Canada will also be contributing toward the project through its Clean Energy Fund. Government funding for this project is expected to be 75% of project costs. For the year ended December 31, 2010, the Company's share of total Government funding received for this project was nil (six months ended December 31, 2009 – nil) and $3 million has been recorded in accounts receivable for this funding at December 31, 2010 (2009 – nil). As long as the project has been completed to the satisfaction of the government parties, none of the recorded amounts are repayable by the Company.

**33. 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**

| | Year ended December 31, 2010 | | | | Six months ended December 31, 2009 | | | |
|---|---|---|---|---|---|---|---|---|
| | Canada | U.S. | Inter-area eliminations | Total | Canada | U.S. | Inter-area eliminations | Total |
| Revenues - external | $ 1,435 | $ 325 | $ - | $1,760 | $ 671 | $ 337 | $ - | $1,008 |
| Inter-area revenues | 4 | 11 | (15) | - | 7 | 1 | (8) | - |
| Total revenues | $ 1,439 | $ 336 | $ (15) | $1,760 | $ 678 | $ 338 | $ (8) | $1,008 |

| | As at December 31, 2010 | | | | As at December 31, 2009 | | | |
|---|---|---|---|---|---|---|---|---|
| | Canada | U.S. | Inter-area eliminations | Total | Canada | U.S. | Inter-area eliminations | Total |
| Property, plant and equipment | $ 3,126 | $ 471 | $ - | $3,597 | $2,734 | $ 503 | $ - | $3,237 |
| Goodwill | $ 104 | $ 35 | $ - | $ 139 | $ 104 | $ 36 | $ - | $ 140 |

Inter-area transactions occur in the normal course of operations and are recorded at the exchange amount which is the consideration established and agreed to by the parties.

**34. Subsequent events:**

On February 17, 2011, a subsidiary of the Company entered into an agreement to acquire two generating facilities from a third party; one facility located in Tiverton, Rhode Island and one facility located in Rumford, Maine. Both plants are natural gas-fired combined cycle power generation facilities serving the New England region in the U.S. Northeast, and have a maximum combined capacity of 549 MW. The transaction is expected to close in April 2011. The US$315 million purchase price for the acquisition will be subject to working capital adjustments and other closing adjustments.

On March 8, 2011, a subsidiary of the Company announced that it had entered into an agreement to acquire a one hundred per cent equity interest in Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport Energy), from a third party. Bridgeport Energy is a natural gas-fired combined cycle power generation facility located in Bridgeport, Connecticut, with a nominal capacity of 520 MW. The transaction is expected to close in May 2011. The US$355 million purchase price for the acquisition will be subject to working capital adjustments and other closing adjustments.

**34. Subsequent events, continued:**

The Company expects to permanently finance both New England acquisitions using a combination of debt and equity. The Company has entered into an agreement to sell 8,100,000 common shares of Capital Power on a bought deal basis at a price of $24.90 per share to a syndicate of underwriters, co-led by TD Securities Inc. and CIBC World Markets Inc., for gross proceeds of $201,690,000. In addition, Capital Power has granted the syndicate an over-allotment option, exercisable for a period of 30 days following closing, to purchase up to an additional 1,215,000 shares which, if exercised, would increase the gross offering size to $231,943,500. The offering is scheduled to close on or about March 17, 2011, and is subject to TSX approval and other customary conditions.

**35. Comparative figures:**

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

Certain 2009 comparative figures have been reclassified to conform with the financial statement presentation adopted in 2010. Refer to Note 2(b) for further details.