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For release: March 13, 2012

Capital Power reports fourth quarter and year-end 2011 results
Year characterized by strong discretionary cash flow generation

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released its financial results for the fourth quarter and year ended December 31, 2011. Funds from operations (FFO), excluding non-controlling interests in Capital Power Income L.P. (CPILP), were $88 million in the fourth quarter of 2011, up 13% from $78 million in the fourth quarter of 2010. Cash flow per share for the quarter was $0.90, compared with $0.97 for the same quarter in the previous year. Normalized earnings attributable to common shareholders in the fourth quarter of 2011, after adjusting for one-time items and fair value adjustments, were $20 million, or $0.36 per share, compared with $5 million, or $0.21 per share, in the comparable period in 2010.

For the full year ended December 31, 2011, FFO excluding non-controlling interests in CPILP increased 27% to $352 million, compared with $277 million in the year ended December 31, 2010. Cash flow per share for the year increased 10% to $3.89. Normalized earnings attributable to common shareholders were $55 million, or $1.24 per share, compared with $31 million, or $1.40 per share, in the previous year.

"Capital Power's fourth quarter financial results underlined the strong cash flow generation from our facilities that was evident throughout the year," said Brian Vaasjo, President and CEO of Capital Power. "We were particularly pleased to achieve a 10% year-over-year gain in cash flow per share in light of the unplanned outage at Genesee 3. During the outage we successfully deployed our Clover Bar Energy Centre peaking facility to partly offset lost production, and with the added contribution from Keephills 3 we delivered full-year plant availability of 92% and met our expectations for full year and fourth quarter normalized earnings."

"Overall, the Company reported financial results for 2011 that exceeded the majority of our financial targets," added Mr. Vaasjo. "In addition to FFO and cash flow per share, the Company met normalized EPS targets and generated substantial discretionary cash flow, with a dividend coverage ratio of 2.1 times consistent with our target."

"In November, we completed the divestiture of our interest in CPILP, simplifying our structure and operations through a more focused geographic footprint and operation of fewer technologies," concluded Mr. Vaasjo. "Looking ahead to 2012, we expect the continued execution of our strategy to produce visible, substantial and growing cash flow. We expect to benefit from a full-year's contribution from Keephills 3 and the initial commercial operations of two wind projects, with further upside potential from the impact of rising Alberta power prices on our unhedged positions. Shareholders can also benefit from participation in our new Dividend Reinvestment Plan, which begins with the first quarter 2012 cash dividend."

Operational and Financial Highlights[1] (unaudited)	**Three months ended December 31**		**Year ended December 31**	
(millions of dollars except per share and operational amounts)	**2011**	**2010**	**2011**	**2010**
Electricity generation (excluding acquired Sundance PPA and CPILP plants) (GWh)	3,780	2,556	13,659	9,205
Generation plant availability (excluding acquired Sundance PPA and CPILP plants) (%)	87%	91%	92%	90%
Revenues and other income	$ 407	$ 435	$ 1,770	$ 1,762
EBITDA [2]	$ 150	$ 91	$ 485	$ 418
Normalized earnings attributable to common shareholders[2]	$ 20	$ 5	$ 55	$ 31
Normalized earnings per share[2]	$ 0.36	$ 0.21	$ 1.24	$ 1.40
Net income (loss) attributable to shareholders	$ 84	$ (3)	$ 77	$ 17
Earnings (loss) per share	$ 1.47	$ (0.13)	$ 1.60	$ 0.77
Dividends declared per common share	$ 0.315	$ 0.315	$ 1.26	$ 1.26
Funds from operations[2]	$ 99	$ 98	$ 433	$ 374
Funds from operations excluding non-controlling interests in CPILP[2]	$ 88	$ 78	$ 352	$ 277
Cash flow per share[2]	$ 0.90	$ 0.97	$ 3.89	$ 3.53
Dividend coverage ratio[2]	1.2	1.8	2.1	2.1
Capital expenditures	$ 177	$ 78	$ 493	$ 329

(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, 2011.

(2) Earnings before finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange losses, and gains on acquisitions and disposals (EBITDA), Funds from operations, Funds from operations excluding non-controlling interests in CPILP, Cash flow per share, and Dividend coverage ratio, Normalized earnings attributable to common shareholders, and Normalized earnings per share are non-GAAP financial measures and do not have standardized meanings under GAAP, and therefore, may not be comparable to similar measures used by other enterprises. See Non-GAAP Financial Measures. Reconciliations of these non-GAAP financial measures to Net income attributable to shareholders, Earnings per share and Net cash flows from operating activities are included in the Company's Management's Discussion and Analysis dated March 13, 2012, which is available under the Company's profile on SEDAR at www.SEDAR.com.

Significant Events

Maintenance outage at Genesee 3

On November 11, 2011, the Genesee 3 plant experienced an unplanned outage that resulted in damage to the turbine/generator bearings and rotor. An interim root cause failure report indicated that the damage was due to an electrical design issue. The unit underwent repairs and was returned to service on January 15, 2012. Incremental repair expenses, net of insurance recoveries, of $2 million were incurred. Additional generation from the Company's Clover Bar Energy Centre peaking facility offset some of the lost production from the Genesee 3 facility.

$224 million secondary offering of Capital Power common shares by EPCOR

In November 2011, a subsidiary of EPCOR exchanged 9,200,000 of its exchangeable limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9,200,000 common shares of Capital Power to the public pursuant to a secondary offering at $24.40 per common share. Capital Power did not receive any of the approximate $224 million of proceeds from EPCOR's sale of common shares. This transaction reduced EPCOR's ownership interest in CPLP to approximately 39% from its interest of approximately 49% at September 30, 2011 and reduced EPCOR's indirect ownership of the common shares of Capital Power on a fully diluted basis to 39% from 49%. EPCOR has advised the Company that it intends to sell all or a portion of its remaining interest in Capital Power subject to market conditions and its requirement for capital in the future.

Closing of Atlantic Power Corporation's acquisition of CPILP

In November 2011, Atlantic Power Corporation (Atlantic Power) acquired all of the outstanding limited partnership units of CPILP, including Capital Power's ownership interest in CPILP. In connection with the transaction, Capital Power acquired CPILP's Roxboro and Southport plants in North Carolina (North Carolina assets) for $121 million. This reduced the number of outstanding limited partnership units of CPILP held by the Company by approximately 6.3 million units. Atlantic Power acquired CPILP and its remaining eighteen facilities outside of North Carolina. Upon closing, Capital Power received $314 million in combined consideration for its ownership interest in CPILP. The consideration included $48 million of stock in Atlantic Power, $145 million of cash and $121 million of North Carolina assets described above. In addition, the Company's management and operations contracts with CPILP were terminated or assigned for consideration of $10 million.

As of June 30, 2011, the Company tested the CPILP net assets and management and operations contracts for impairment at the cash generating unit level, by comparing their recoverable amounts with their carrying amounts. The negotiated consideration for these assets less an estimate for disposal costs was used as the estimated recoverable amount. As a result, the management and operations contracts were determined to be impaired and an impairment loss of $43 million was recorded in the second quarter of 2011. The carrying amounts of the disposal group of assets and liabilities, after recognizing the impairment loss, were reclassified as assets and liabilities held for sale commencing with the Company's statement of financial position as at June 30, 2011. The Company recognized a total pre-tax gain of $89 million, net of legal and other disposal costs of $10 million, for the difference between the net proceeds received in November 2011 and the carrying amount of the Company's interest in CPILP net assets classified as assets held for sale.

Upon close of the disposal transactions, accumulated other comprehensive income included accumulated losses of $21 million relating to the Company's investment in CPILP, which included $11 million of losses related to foreign currency translation losses that were previously recognized directly in accumulated other income. All accumulated other comprehensive losses relating to the Company's interest in CPILP were reclassified to net income as a deduction in arriving at the gain on disposal.

Sale of Taylor Coulee Chute

On November 1, 2011, in conjunction with Capital Power's corporate strategy to divest its interest in hydro facilities, the Company sold its interest in Taylor Coulee Chute to TransAlta Corporation (TransAlta) for total proceeds of $8 million. A pre-tax gain of $4 million was recorded upon disposal.

Keephills 3 power plant begins commercial operation

On September 1, 2011, the Company and TransAlta completed the 495 MW (gross) Keephills 3 generating facility, which is now in commercial operation. The facility is the most technologically advanced coal-fired plant in Canada and the Company's share of the plant's final cost was $949 million. Costs for the plant, excluding mine capital, are being equally shared by its owners; Capital Power, which led the construction, and TransAlta, which operates the plant.

Development of K2 Wind Ontario project

On August 3, 2011, CPLP closed a limited partnership agreement with Samsung Renewable Energy Inc. (Samsung) and Pattern Renewable Holdings Canada ULC (Pattern) for the development, construction and operation of a 270 megawatt (MW) wind power project named K2 Wind Ontario (K2). Formerly referred to as the Kingsbridge II Wind Power Project, K2 will be developed in the Township of Ashfield-Colborne-Wawanosh in southwestern Ontario. The project has an expected total capital cost of $874 million, most of which will be funded through project financing.

The Ontario Power Authority has signed a power purchase arrangement (PPA) for K2. The completion of the project is subject to receiving regulatory approvals. The partners expect that construction would begin in 2013, with commercial operation in 2014.

At commencement of commercial operation, each of the three partners will have an equal economic interest in the project. Capital Power will contribute the project lease agreements and development work completed to August 3, 2011, while Samsung and Pattern will contribute the PPA and transmission access rights. Capital Power will continue to lead the provincial Renewal Energy Approval process for the project. Samsung will serve as the engineering procurement and construction contractor, and the K2 partnership will finalize the turbine model and supplier.

$231 million common share offering

In July 2011, the Company closed an offering to sell 9,200,000 common shares at a price of $25.10 per share to a syndicate of underwriters for gross proceeds of $231 million less underwriters' fees of approximately $9 million. The net proceeds from the common share offering were used to purchase an additional 9,200,000 common limited partnership units of CPLP. CPLP used the funds to repay a portion of the indebtedness outstanding under its credit facilities, which was drawn to fund the acquisitions of the New England facilities described below, and for general corporate purposes including financing development projects and working capital requirements.

US$295 million private placement of senior notes

On June 15, 2011, Capital Power U.S. Financing LP, an indirect subsidiary of CPLP, announced that it had closed a US$295 million private placement of senior notes. The net proceeds from the transaction were used to repay a portion of the debt outstanding under its credit facilities, which was drawn to fund the acquisitions of the New England facilities described below, and for general corporate purposes.

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

Acquisition of Halkirk Wind Project

In June 2011, CPLP announced that it had acquired 100% of Halkirk I Wind Project LP and Halkirk I Wind Project Ltd. from Greengate Power Corporation for $33 million. The assets of the acquired entities were comprised of intangible assets including various permits and land lease rights required to construct the Halkirk Wind Project (Halkirk), and a 20-year purchase and sale agreement for the sale of renewable energy credits to a third party. Halkirk is a 150-MW wind farm located in east central Alberta, which Capital Power will build, own and operate. All approvals and permits from the Alberta Utilities Commission (AUC) and Alberta Environment are in place for the Capital Power facility. The AUC permit for the high voltage transmission and substation interconnection is expected in the first quarter of 2012.

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

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

Acquisition of three New England power plants

On April 28, 2011, CPLP acquired 100% of the equity interests in Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport), for $346 million (US$363 million) including a working capital adjustment of $8 million (US$8 million). Bridgeport is a natural gas-fired combined cycle power generation plant located in Bridgeport, Connecticut, with a net winter capacity of 540 MW.

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

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

$300 million debt offering

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

$232 million common share offering

In March 2011, the Company issued and sold 9,315,000 common shares at a price of $24.90 per share to a syndicate of underwriters for gross proceeds of $232 million less issue costs of $9 million. The net proceeds from the common share offering were used to repay a portion of the outstanding indebtedness under the Company’s credit facilities.

Subsequent Events

On February 10, 2012, the Company completed the sale of its shares in Atlantic Power, which were acquired in November 2011 as part of the Atlantic Power acquisition of CPILP, for proceeds of $52 million on a bought deal basis. These shares were initially recorded at $48 million and subsequently adjusted to their fair value of $53 million as of December 31, 2011 resulting in a gain of $5 million recognized in 2011. From the date of acquisition to the date of disposal, the expected realized pre-tax gain on disposal will be approximately $4 million with cash income taxes estimated to be $1 million.

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

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

Dividend Reinvestment Plan

The Company announced the launch of a Dividend Reinvestment Plan (the Plan) effective January 1, 2012. Eligible shareholders may elect to participate in the Plan commencing with the Company's first quarter 2012 cash dividend. The Plan will provide eligible shareholders with an alternative to receiving their quarterly cash dividends. Under the Plan, eligible shareholders may elect to efficiently and cost-effectively accumulate additional shares in the Company by reinvesting their quarterly cash dividends on the applicable dividend payment date in new shares issued from treasury. The new shares purchased with reinvested dividends will be bought at 95 per cent of the average market price. No commissions, service charges or similar fees will be payable in connection with the purchase of shares from treasury under the Plan. All administrative costs of the Plan will be paid by the Company. Shareholders who wish to participate in the Plan indirectly through the brokers, investment dealers, financial institutions or other similar nominees through which their shares are held should consult such nominees to confirm whether commissions, service charges or similar fees are payable.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on March 14, 2012 at 1:00 pm (ET) to discuss fourth quarter results. The conference call dial-in numbers are:

(403) 532-5601 (Calgary)
(604) 681-8564 (Vancouver)
(416) 623-0333 (Toronto)
(855) 353-9183 (toll-free from Canada and USA)

Participant access code for the call: 21543#

A replay of the conference call will be available following the call at: (855) 201-2300 (toll-free) and entering conference reference number 764919# followed by participant code 21543#. The replay will be available until midnight on April 16, 2012.

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

Non-GAAP Financial Measures

The Company uses (i) EBITDA, (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) cash flow per share, (v) dividend coverage ratio, (vi) normalized earnings attributable to common shareholders, and (vii) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective. Reconciliations of EBITDA to net income, funds from operations and funds from operations excluding non-controlling interests in CPILP to net cash flows from operating activities, normalized earnings attributable to common shareholders to net income attributable to common shareholders, and normalized earnings per share to earnings per share are contained in the Company's Management's Discussion and Analysis dated March 13, 2012 for the year ended December 31, 2011 which is available under the Company's profile on SEDAR at www.SEDAR.com.

Forward-looking Information

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

Material forward-looking information in this press release includes information with respect to: (i) expectations related to execution of strategy, (ii) expectations related to recently completed projects and projects under development, and (iii) expectations regarding impact of power prices.

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

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are: (i) power plant availability and performance including maintenance expenditures, (ii) changes in electricity prices in markets in which the Company operates, (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) acquisitions and developments including timing and costs of regulatory approvals and construction; (v) ability to fund current and future capital and working capital needs, (vi) changes in energy commodity market prices and use of derivatives, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's Management's Discussion and Analysis dated March 13, 2012 for further discussion of these and other risks.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated March 13, 2012, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the years ended December 31, 2011 and December 31, 2010, the annual information form (AIF) of Capital Power Corporation dated March 13, 2012 and the cautionary statements regarding forward-looking information which begins on page 3. 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.

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

In this MD&A, financial information for the years ended December 31, 2011 and December 31, 2010 is based on the audited consolidated financial statements of the Company which were prepared in accordance with GAAP and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors has approved this MD&A as of March 13, 2012.

Contents

The Business

Capital Power is a growth-oriented North American power producer headquartered in Edmonton, Alberta. The Company develops, acquires, operates and optimizes power generation from a variety of energy sources. Capital Power owns more than 3,300 megawatts (MW) of power generation capacity at 16 facilities across North America and has rights to 371 MW through its interest in the acquired Sundance power purchase arrangement (acquired Sundance PPA). An additional 487 MW of owned wind generation capacity is under construction or in advanced development in Alberta, British Columbia, and Ontario.

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP), a subsidiary of the Company. As at December 31, 2011, the Company directly and indirectly held approximately 21.750 million general partnership units and 36.924 million common limited partnership units of CPLP which represented approximately 61% of CPLP's total partnership units. EPCOR (in this MD&A, EPCOR refers to EPCOR Utilities Inc. collectively with its subsidiaries) held 38.216 million exchangeable common limited partnership units of CPLP representing approximately 39% of CPLP. CPLP's exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis. The general partner of CPLP is wholly-owned by Capital Power Corporation and EPCOR's representation on the Board of Directors does not represent a controlling vote. Accordingly, Capital Power Corporation controls CPLP and the operations of CPLP have been consolidated for financial statement purposes.

Corporate Strategy

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. The Company also remains committed to a culture of zero injury and occupational illness.

Financial discipline

Capital Power is committed to a policy of financial discipline founded upon operational success, contracted generation assets 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.

Sustainable growth

The Company has a pipeline of solid projects under construction or development. Building on the success of Genesee 3 and Clover Bar Energy Centre (CBEC), the Keephills 3 facility was successfully commissioned on September 1, 2011. The Keephills 3 facility represents 495 MW of new generation capacity, of which Capital Power has a 50% ownership interest. Wind power projects currently under construction are Quality Wind in British Columbia (142 MW) and Halkirk Wind (Halkirk) in Alberta (150 MW). Wind power projects currently under development are Port Dover & Nanticoke Wind (Port Dover & Nanticoke) in Ontario (105 MW) and K2 Wind Power Project (K2) in Ontario (270 MW with Capital Power's ownership interest being 90 MW).

In 2011, the Company acquired three natural gas-fired combined cycle power generating facilities in the New England states with a combined capacity of 1,069 MW, It also acquired two mixed fuel generating plants in North Carolina with a combined capacity of 155 MW that were previously owned by its former subsidiary, Capital Power Income L.P. (CPILP). See Significant Events. These acquisitions were incremental to the Company's 2010 acquisition of Island Generation, a 275 MW gas-fired combined cycle power plant in British Columbia.

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 in acquiring high quality assets. 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. As part of the Company's growth strategy through developing and building new assets, 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. As a result of this process, described under Significant Events, Capital Power disposed of their interest in CPILP on November 5, 2011.

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.

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 a mix of unit specific and 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 optimize its portfolio of assets in the networked hub in response to changes in commodity prices. The Company believes that its approach of managing assets at the hub level improves efficiency and reduces risk through portfolio diversification.

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 North East U.S., including the New York Independent System Operator and the New England Power Pool (NEPOOL); and the South West U.S., including the California Independent System Operator and Desert South West (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.

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 wind 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. The Company will no longer pursue growth opportunities in biomass and hydro technologies. However, given the emerging opportunities in the Company's target markets, the Company is pursuing development and acquisition opportunities for solar power.

Forward-looking Information

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

Material forward-looking information in this MD&A includes information with respect to: (i) expectations related to future earnings and funds from operations, (ii) expectations regarding the future pricing of electricity and market fundamentals in existing and target markets, (iii) expectations regarding fuel supply and pricing, (iv) expectations related to the Company's future cash requirements including interest and principal repayments, capital expenditures and dividends, (v) expectations for the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings, (vi) expectations regarding future growth and emerging opportunities in the Company's target markets including the focus on certain technologies, (vii) expectations regarding the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions, and (viii) expectations regarding plant availability, and (ix) expectations regarding capital expenditures for plant maintenance and other.

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

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are: (i) power plant availability and performance including maintenance expenditures, (ii) changes in electricity prices in markets in which the Company operates, (iii) regulatory and political environments including changes to environmental, financial reporting and tax legislation, (iv) acquisitions and developments including timing and costs of regulatory approvals and construction, (v) ability to fund current and future capital and working capital needs, (vi) changes in energy commodity market prices and use of derivatives, (vii) changes in market prices and availability of fuel, and (viii) changes in general economic and competitive conditions. See Risks and Risk Management for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

Performance Overview

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

Operational excellence

Performance measures	2011 targets	2011 actual results
Plant availability average	94% or greater	92%
Capital expenditures for plant maintenance and Genesee mine extension	Approximately $56 million	$71 million

The Company's plant availability averaged 92% for 2011 compared with a target of 94%. Keephills 3, Joffre and Genesee Units 1 and 2 performed better than anticipated; however, the overall under-performance was primarily attributable to the unplanned outage experienced at Genesee 3 from November 11, 2011 to January 15, 2012 and at CBEC Unit 3 from January 15 to June 17, 2011.

Capital expenditures for maintenance of the plants excluding the CPILP plants and the Genesee mine were $71 million for 2011. The increase compared with the target of $56 million was primarily due to the unbudgeted capital maintenance of $14 million for the New England plants acquired in 2011.

Financial stability and strength

Performance measures	2011 targets	2011 actual results
Normalized earnings per share (1)	$1.16 (2)	$1.24
Funds from operations excluding non-controlling interests in CPILP (1)	Modestly higher than the 2010 result of $277 million (3)	$352 million
Cash flow per share (1)	Modestly higher than the 2010 result of $3.53 (4)	$3.89
Dividend coverage ratio (1)	Modestly higher than the 2010 result of 2.1 times	2.1 times

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

(2) The original normalized earnings per share target of $1.20 under previous CGAAP equates to approximately $1.16 under current GAAP.

(3) The original funds from operations excluding non-controlling interests in CPILP target of "Modestly higher than the 2010 result of $257 million" was amended to reflect the revised actual funds from operations excluding non-controlling interests of $277 million for the year ended December 31, 2010.

(4) The original cash flow per share target of "Modestly higher than the 2010 result of $3.28" was amended to reflect the revised actual cash flow per share of $3.53 million for the year ended December 31, 2010.

The Company's operating results for the year ended December 31, 2011 were mainly ahead of management's expectations. In the third quarter of 2011, the Company's forecast for normalized earnings per share was $1.40 for the year less the impact of the loss on the settlement of the forward bond contracts and an increase in the Company's pension obligation recognized in the second quarter of 2011. Actual normalized earnings per share were in line with this expectation.

Factors impacting the variance between actual financial results achieved in 2011 as compared with the 2011 financial targets included the following:

- Higher EBITDA [(1)], excluding unrealized fair value changes, from the Alberta commercial plants (see Results by Plant Category and Other).
- Higher EBITDA [(1)] from the Alberta contracted plants as a result of higher availability incentive payments.
- Lower than expected EBITDA [(1)] excluding fair value changes from the North East U.S. commercial plants and portfolio optimization (see Results by Plant Category and Other).
- EBITDA is lower than expected since the Company completed its divestiture of its interest in CPILP in November 2011. Actual EBITDA includes approximately ten months of results compared with financial target expectations based on a full year's results.

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

Enhancing shareholders' value

Performance measures	2011 targets	2011 actual results
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	$949 million; commercial operation began on September 1, 2011.
Quality Wind and Port Dover & Nanticoke wind projects	Continue on time and on budget with commercial operation dates in 2012	Quality Wind in-line with target; Port Dover & Nanticoke's commercial operation date anticipated in 2013.

In 2010, the Company disclosed that the Port Dover & Nanticoke wind project was expected to enter commercial operation in the fourth quarter of 2012. However, the construction schedule for the Port Dover & Nanticoke wind project was revised to accommodate completion of the land title transfers and regulatory proceedings resulting in $57 million of planned expenditures being deferred to 2012. The change is not anticipated to impact the total project cost of $340 million but the project's completion date is expected to be delayed until 2013 given the delay in regulatory approvals.

Disciplined growth

Performance measure	2011 targets	2011 actual results
Committed capital for acquisitions / developments that are in-line with targeted rates of return	$1.5 billion or higher	$1.4 billion committed

The New England plant acquisitions, Halkirk wind project, K2 wind project, and the North Carolina plant acquisitions (see Significant Events) contributed approximately $1.4 billion towards the Company's target of $1.5 billion of capital committed in 2011.

Targets for 2012

The following table provides the Company's performance measure targets for 2012:

Performance measure	2012 target
Operational	
Plant availability average	91% or greater
Capital expenditures for plant maintenance, Genesee mine extension, and other	$108 million or lower
Maintenance and operating expenses	$215 million to $235 million
Financial	
Normalized earnings per share (1)	$1.50 to $1.70
Funds from operations (1)	$380 million to $420 million
Cash flow per share (1)	$3.90 to $4.30
Dividend coverage ratio (1)	2.2 times to 2.6 times
Construction / Development	
Quality Wind and Halkirk wind projects	Continue on time and on budget with commercial operation dates in the fourth quarter of 2012
Port Dover & Nanticoke and K2 wind projects	Full notice to proceed in 2012

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

Corporate responsibility report

Capital Power received an A+ rating for its 2010 Corporate Responsibility Report, "What's Behind Our Performance?" The report discloses the Company's challenges and accomplishments with respect to corporate responsibilities and 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 website at www.capitalpower.com.

Outlook

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A which identifies the material factors and assumptions used to develop forward-looking information and their material associated risk factors. Based upon a forecast average Alberta power price of approximately $74 per megawatt hour (MWh), normalized earnings per share and funds from operations for 2012 are expected to exceed the levels achieved in 2011. Items impacting the year-over-year comparison are as follows:

The Company's forecast for average Alberta power prices in 2012 is similar to those experienced in 2011. Thus, the Company expects similar realized prices on its economically unhedged position, profitability from the peaking facilities, and incentive revenues from Genesee 1 and 2.

- The forecast 2011 generation, at the beginning of 2011, from the baseload plants and acquired Sundance PPA in the Alberta commercial portfolio was 73% sold forward at an average price of low-$60 per MWh compared with the following portfolio positions for 2012, 2013, and 2014:

Alberta commercial portfolio positions and power prices	2012	2013	2014
Percentage sold forward	48%	20%	5%
Contracted price	High-$60 per MWh	Mid-$60 per MWh	Low-$60 per MWh

- While the Company's forecast for Alberta spot power prices for 2012 is similar to actual 2011 prices, the lower hedged position in 2012 is expected to result in higher realized prices for the portfolio.
- 2012 results will include a full year of operations from the New England facilities acquired in April 2011 and from Keephills 3 which began commercial operation in September 2011 (see Significant Events). The New England facilities are expected to contribute EBITDA of $51 million in 2012.
- The above favourable factors are partly offset by the lower plant availability target of 91%. In 2012, Capital Power has scheduled two maintenance outages, one at Genesee 2 and one at Genesee 3, compared with one scheduled maintenance outage expected at the beginning of 2011. The outage at Genesee 2 is expected to last 25 days and cost approximately $15 million in maintenance expenses and $12 million in

availability penalties. The outage at Genesee 3 is expected to last 28 days and Capital Power's portion of the maintenance cost is expected to be $9 million.

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

The Company's estimated 2012 capital expenditures in the following table only include expenditures for previously identified growth projects and exclude the cost of potential new development projects:

(unaudited, $millions) **Capital expenditures – growth**	**Target completion date**	**Year ended December 31, 2012 estimated**
Quality Wind	4th quarter 2012	$ 300
Halkirk	4th quarter 2012	174
Port Dover & Nanticoke	4th quarter 2013	52
K2 (1)	2014	46
		$ 572

(1) As discussed under Significant Events, Capital Power entered into a partnership agreement to develop K2 which is expected to be in operation by 2014. The 2012 capital expenditures estimated for the K2 project consist primarily of the Company's estimated contribution towards the partnership's equity.

(unaudited, $millions) **Capital expenditures – sustaining**	**Year ended December 31, 2012 estimated**
Plant maintenance	$ 73
Genesee mine maintenance (1) (2)	29
Information technology (3)	21
Other	1
	$ 124

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

(2) Included in the estimated capital expenditures for Genesee mine maintenance is approximately $16 million relating to purchase of lands for ongoing expansion of the mine.

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

Non-GAAP Financial Measures

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

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, gross income, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective.

EBITDA

Capital Power uses EBITDA to measure the operating performance of plants and groups of plants from period to period. For previously reported periods, the Company defined EBITDA as earnings before finance expense, income tax expense and depreciation and amortization. Commencing with this MD&A, EBITDA has been redefined to also exclude impairments, foreign exchange losses and gains on acquisitions and disposals. Management believes that EBITDA, as a measure of plant operating performance, is more meaningful if results not related to plant operations such as impairments, foreign exchange losses and gains on acquisitions and disposals are excluded from the EBITDA measure. All comparative EBITDA amounts for quarters and years prior to those ended on December 31, 2011 have been revised to reflect this change. A reconciliation of EBITDA to net income is as follows:

(unaudited, $millions)	**Year ended December 31**		**Three months ended**							
	2011	**2010**	**Dec 2011**	**Sep 2011**	**Jun 2011**	**Mar 2011**	**Dec 2010**	**Sep 2010**	**Jun 2010**	**Mar 2010**
Revenues	$ 1,691	$ 1,707	$ 382	$ 414	$ 455	$ 440	$ 430	$ 492	$ 301	$484
Other income	79	55	25	19	17	18	5	21	12	17
Energy purchases and fuel	(904)	(990)	(169)	(189)	(255)	(291)	(233)	(277)	(196)	(284)
Gross income	866	772	238	244	217	167	202	236	117	217
Other raw materials and operating charges	(149)	(104)	(40)	(43)	(37)	(29)	(43)	(20)	(22)	(19)
Staff costs and employee benefits expense	(155)	(175)	(34)	(40)	(42)	(39)	(44)	(43)	(47)	(41)
Other administrative expenses	(56)	(57)	(10)	(16)	(20)	(10)	(20)	(18)	(9)	(10)
Property taxes	(21)	(18)	(4)	(6)	(6)	(5)	(4)	(5)	(4)	(5)
EBITDA	**485**	**418**	**150**	**139**	**112**	**84**	**91**	**150**	**35**	**142**
Depreciation and amortization	(229)	(241)	(62)	(45)	(64)	(58)	(63)	(59)	(62)	(57)
Impairments	(43)	(65)	-	-	(43)	-	1	(66)	-	-
Foreign exchange losses	(13)	(1)	-	(7)	(4)	(2)	(1)	(1)	2	(1)
Gains on acquisitions and disposals	93	30	93	-	-	-	2	-	-	28
Finance expense	(105)	(78)	(29)	(32)	(35)	(9)	(13)	(26)	(20)	(19)
Income tax recovery (expense)	-	14	-	(11)	12	(1)	5	(1)	11	(1)
Net income (loss)	**$ 188**	**$ 77**	**$ 152**	**$ 44**	**$ (22)**	**$ 14**	**$ 22**	**$ (3)**	**$ (34)**	**$ 92**
Attributable to:										
Non-controlling interests	$ 111	$ 60	$ 68	$ 29	$ 3	$ 11	$ 25	$ (19)	$ (26)	$ 80
Shareholders of the Company	$ 77	$ 17	$ 84	$ 15	$ (25)	$ 3	$ (3)	$ 16	$ (8)	$ 12

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

Capital Power uses funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund capital expenditures, debt repayments and distributions to the Company's shareholders. Funds from operations are net cash flows from operating activities, including finance and current income tax expenses, and excluding changes in working capital. The Company includes interest and current income tax expenses recorded during the year rather than interest and income taxes paid. The timing of cash receipts and payments of interest and income taxes and the resulting cash basis amounts are not comparable from year to year. The timing of cash receipts and payments also affects the year-to-year comparability of changes in operating working capital which are also excluded from funds from operations. Since the non-controlling interests in CPILP's funds from operations were approximately 71% until Atlantic Power Corporation's acquisition of CPILP (see Significant Events), the Company used funds from operations excluding non-controlling interests in CPILP to provide a more meaningful measure of the Company's operating cash flows.

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

(unaudited, $millions)	Year ended December 31		Three months ended December 31	
	2011	**2010**	**2011**	**2010**
Net cash flows from operating activities per Consolidated Statements of Cash Flows	**$ 461**	**$ 391**	**$ 151**	**$ 103**
Unrealized changes in the fair value of forward bond contracts	2	6	4	(5)
Settlement of forward bond contracts	12	-	-	-
Miscellaneous financing charges	8	10	2	1
Finance expense	(105)	(78)	(29)	(13)
Interest paid	88	58	44	12
Current income tax (expense) excluding future income taxes	(5)	(10)	(5)	2
Income taxes paid (recovered)	14	(9)	1	1
Change in non-cash operating working capital	(42)	6	(69)	(3)
Funds from operations	**433**	**374**	**99**	**98**
Less funds from operations due to non-controlling interests in CPILP	81	97	11	20
Funds from operations excluding non-controlling interests in CPILP	**$ 352**	**$ 277**	**$ 88**	**$ 78**

Cash flow per share

Cash flow per share is calculated using the weighted average common shares of Capital Power Corporation and exchangeable common limited partnership units of CPLP that were outstanding during the period. The CPLP exchangeable common limited partnership units are exchangeable for common shares of Capital Power Corporation on a one-for-one basis.

(unaudited)	Year ended December 31		Three months ended December 31	
	2011	**2010**	**2011**	**2010**
Funds from operations excluding non-controlling interests in CPILP ($millions)	**$ 352**	**$ 277**	**$ 88**	**$ 78**
Weighted average common shares outstanding (millions)	44.25	22.19	55.64	23.47
Weighted average exchangeable common limited partnership units of CPLP outstanding (millions)	46.13	56.19	42.32	56.63
Weighted average shares and partnership units outstanding (millions)	90.38	78.38	97.96	80.01
Cash flow per share	**$ 3.89**	**$ 3.53**	**$ 0.90**	**$ 0.97**

Dividend coverage ratio

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

(unaudited, $millions except dividend coverage ratio)	**Year ended December 31**		**Three months ended December 31**	
	2011	**2010**	**2011**	**2010**
Funds from operations excluding non-controlling interests in CPILP	**$ 352**	**$ 277**	**$ 88**	**$ 78**
Less CPLP sustaining capital expenditures	92	67	47	32
Less CPLP's share of CPILP sustaining capital expenditures	6	2	1	1
Funds available for distribution	$ 254	$ 208	$ 40	$ 45
Common share dividends declared	60	30	18	10
Distributions to exchangeable common limited partnership unitholders of CPLP declared	57	68	12	15
Preferred share dividends declared	6	-	2	-
Total dividends and distributions declared	$ 123	$ 98	$ 32	$ 25
Dividend coverage ratio	**2.1**	**2.1**	**1.2**	**1.8**

Normalized earnings attributable to common shareholders and normalized earnings per share

The Company uses normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings per share is based on earnings used in the calculation of earnings per share according to GAAP adjusted for items that are not reflective of performance in the period such as fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or unusual contracts, and foreign exchange loss on the translation of U.S. dollar denominated debt. The foreign exchange gain on the translation of the New England plant assets which were financed by this U.S. debt was recognized in other comprehensive income as required by GAAP. However, the related U.S. debt is not part of the New England foreign investment since the Company has a centralized finance function. As a result of this mismatch in the income statement, the foreign exchange loss was excluded from normalized earnings. A reconciliation of net income (loss) attributable to shareholders to normalized earnings attributable to common shareholders, and earnings (loss) per share to normalized earnings per share is as follows:

(unaudited, $millions except earnings (loss) per share and number of common shares)	**Year ended December 31**		**Three months ended**							
	2011	**2010**	**Dec 2011**	**Sep 2011**	**Jun 2011**	**Mar 2011**	**Dec 2010**	**Sep 2010**	**Jun 2010**	**Mar 2010**
Earnings (loss) per share	**$1.60**	**$0.77**	**$1.47**	**$0.29**	**$(0.67)**	**$0.06**	**$(0.13)**	**$0.74**	**$(0.37)**	**$0.55**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income	**77**	**17**	**84**	**15**	**(25)**	**3**	**(3)**	**16**	**(8)**	**12**
Preferred share dividends	(6)	-	(2)	(1)	(2)	(1)	-	-	-	-
Earnings (loss) attributable to common shareholders	71	17	82	14	(27)	2	(3)	16	(8)	12
Unrealized changes in fair value of CPLP's derivative instruments and natural gas held for trading	15	9	2	2	2	9	3	(2)	8	-
Unrealized changes in fair value of CPILP's derivative instruments	1	-	(1)	2	-	-	(1)	-	1	-
Foreign exchange losses on translation of U.S. dollar debt	2	-	-	2	-	-	-	-	-	-
Impact of change in non-controlling interest percentage on adjustments of previous quarters	2	1	1	1	-	-	1	-	-	-
Impairment loss on manager and operating contracts	30	-	-	-	30	-	-	-	-	-
Impact of asset impairments recognized by subsidiaries	-	(5)	-	-	-	-	-	(5)	-	-
Gain on sale of CPILP	(60)	-	(60)	-	-	-	-	-	-	-
Gain on sale of Taylor Coulee Chute	(1)	-	(1)	-	-	-	-	-	-	-
Gain on settlement of pension expense from sale of CPILP	(3)	-	(3)	-	-	-	-	-	-	-
Obligation to EPCOR for Rossdale plant	-	2	-	-	-	-	-	2	-	-
Acquisition loss for Island Generation acquisition	-	6	-	-	-	-	6	-	-	
Income tax adjustments	(2)	1	-	-	(2)	-	(1)	3	-	(1)
Normalized earnings attributable to common shareholders	**55**	**31**	**20**	**21**	**3**	**11**	**5**	**14**	**1**	**11**
Weighted average number of common shares outstanding (millions)	44.25	22.19	55.64	48.33	40.42	32.32	23.47	21.77	21.75	21.75
Normalized earnings per share	**$1.24**	**$1.40**	**$0.36**	**$0.43**	**$0.07**	**$0.33**	**$0.21**	**$0.64**	**$0.05**	**$0.51**

Financial Highlights

(unaudited, $millions, except earnings per share) **Year ended December 31** [1]	**2011**	**2010**
Revenues and other income	$ 1,770	$ 1,762
EBITDA [2]	485	418
Net income	188	77
Net income attributable to shareholders of the Company	77	17
Normalized earnings attributable to common shareholders [2]	55	32
Earnings per share	$ 1.60	$ 0.77
Diluted earnings per share [3]	$ 1.59	$ 0.69
Normalized earnings per share [2]	$ 1.24	$ 1.40
Funds from operations [2]	433	374
Funds from operations excluding non-controlling interests in CPILP [2]	352	277
Cash flow per share [2]	$ 3.89	$ 3.53
Capital expenditures	493	329
Dividend coverage ratio [2]	2.1	2.1
Dividends per common share, declared and paid	$ 1.26	$ 1.26
Dividends per preferred share, declared and paid	$ 1.19	$ -

As at December 31	**2011**	**2010**
Loans and borrowings including current portion	$ 1,480	$ 1,869
Total assets	4,743	5,296

(1) Comparative amounts for 2009 have not been presented since the previously issued financial statements were not prepared or retrospectively adjusted in accordance with IFRS.

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

(3) Diluted earnings per share is calculated after giving effect to share purchase options and, the exchange of common limited partnership units of CPLP held by EPCOR which are exchangeable for common shares of Capital Power Corporation on a one-for-one basis.

Normalized earnings and normalized earnings per share

For the year ended December 31, 2011, the decrease in normalized earnings attributable to common shareholders compared with the previous year primarily reflected the issuance of additional equity in 2011, lower than expected contributions from the New England facilities, and losses realized on the settlement of forward bond contracts partly offset by higher EBITDA from the Alberta plants and contributions from the Island Generation plant.

Normalized earnings per share for 2011 and 2010 reflected normalized earnings attributable to common shareholders divided by 44.25 million and 22.19 million weighted average common shares outstanding, respectively. See Non-GAAP Financial Measures.

Funds from operations

As described under Significant Events, the Company divested its 29% indirect ownership of CPILP as of November 5, 2011. Prior to the sale, the Company used funds from operations excluding non-controlling interests in CPILP to provide a more meaningful measure of the Company's operating cash flows since the non-controlling interests in CPILP's funds from operations were approximately 71%. See Non-GAAP Financial Measures.

Significant Events

Maintenance outage at Genesee 3

On November 11, 2011, the Genesee 3 plant experienced an unplanned outage that resulted in damage to the turbine/generator bearings and rotor. An interim root cause failure report indicated that the damage was due to an electrical design issue. The unit underwent repairs and was returned to service on January 15, 2012. Incremental repair expenses, net of insurance recoveries, of $2 million were incurred. Additional generation from the Company's CBEC peaking facility offset some of the lost production from the Genesee 3 facility.

$224 million secondary offering of Capital Power common shares by EPCOR

In November 2011, a subsidiary of EPCOR exchanged 9,200,000 of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis and sold 9,200,000 common shares of Capital Power to the public pursuant to a secondary offering at $24.40 per common share. Capital Power did not receive any of the approximate $224 million of proceeds from EPCOR's sale of common shares. This transaction reduced EPCOR's ownership interest in CPLP to approximately 39% from its interest of approximately 49% at September 30, 2011 and reduced EPCOR's indirect ownership of the common shares of Capital Power on a diluted basis to 39% from 49%. EPCOR has advised the Company that it intends to sell all or a portion of its remaining interest in Capital Power subject to market conditions and its requirement for capital in the future.

Closing of Atlantic Power Corporation's acquisition of CPILP

In November 2011, Atlantic Power Corporation (Atlantic Power) acquired all of the outstanding limited partnership units of CPILP, including Capital Power's ownership interest in CPILP. In connection with the transaction, Capital Power acquired CPILP's Roxboro and Southport plants in North Carolina (North Carolina assets) for $121 million. This reduced the number of outstanding limited partnership units of CPILP held by the Company by approximately 6.3 million units. Atlantic Power acquired CPILP and its remaining eighteen facilities outside of North Carolina. Upon closing, Capital Power received $314 million in combined consideration for its ownership interest in CPILP. The consideration included $48 million of stock in Atlantic Power, $145 million of cash and $121 million of North Carolina assets described above. In addition, the Company's management and operations contracts with CPILP were terminated or assigned for consideration of $10 million.

As of June 30, 2011, the Company tested the CPILP net assets and management and operations contracts for impairment at the cash generating unit level, by comparing their recoverable amounts with their carrying amounts. The negotiated consideration for these assets less an estimate for disposal costs was used as the estimated recoverable amount. As a result, the management and operations contracts were determined to be impaired and an impairment loss of $43 million was recorded in the second quarter of 2011. The carrying amounts of the disposal group of assets and liabilities, after recognizing the impairment loss, were reclassified as assets and liabilities held for sale commencing with the Company's statement of financial position as at June 30, 2011. The Company recognized a total pre-tax gain of $89 million, net of legal and other disposal costs of $10 million, for the difference between the net proceeds received in November 2011 and the carrying amount of the Company's interest in CPILP net assets classified as assets held for sale.

Upon close of the disposal transactions, accumulated losses of $21 million relating to the Company's investment in CPILP were included in accumulated other comprehensive income. All accumulated other comprehensive losses relating to the Company's investment in CPILP were reclassified to net income, within the gain on disposal, upon close of the disposal transactions.

Sale of Taylor Coulee Chute

On November 1, 2011, in conjunction with Capital Power's corporate strategy to divest its interest in hydro facilities, the Company sold its interest in Taylor Coulee Chute to TransAlta Corporation (TransAlta) for total proceeds of $8 million. A pre-tax gain of $4 million was recorded upon disposal.

Keephills 3 power plant begins commercial operation

On September 1, 2011, the Company and TransAlta completed the 495 MW (gross) Keephills 3 generating facility, which is now in commercial operation. The facility is the most technologically advanced coal-fired plant in Canada and the Company's share of the plant's final cost was $949 million. Costs for the plant, excluding mine capital, are being equally shared by its owners: Capital Power which led the construction and TransAlta which operates the plant.

Development of K2 Wind Power Project

On August 3, 2011, CPLP closed a limited partnership agreement with Samsung Renewable Energy Inc. (Samsung) and Pattern Renewable Holdings Canada ULC (Pattern) for the development, construction and operation of a 270 megawatt (MW) wind power project called the K2 Wind Power Project (K2). Formerly referred to as the Kingsbridge II Wind Power Project, K2 will be developed in the Township of Ashfield-Colborne-Wawanosh in southwestern Ontario. The project has an expected total capital cost of $874 million, most of which will be funded through project financing.

The Ontario Power Authority has signed a power purchase arrangement (PPA) for K2. The completion of the project is subject to receiving regulatory approvals. The partners expect that construction would begin in 2013, with commercial operation in 2014.

At commencement of commercial operation, each of the three partners will have an equal economic interest in the project. Capital Power will contribute the project lease agreements and development work completed to August 3, 2011, while Samsung and Pattern will contribute the PPA and transmission access rights. Capital Power will continue to lead the provincial Renewal Energy Approval process for the project. Samsung will serve as the engineering procurement and construction contractor, and the K2 partnership will finalize the turbine model and supplier.

$231 million common share offering

In July 2011, the Company closed an offering to sell 9,200,000 common shares at a price of $25.10 per share to a syndicate of underwriters for gross proceeds of $231 million less underwriters' fees of approximately $9 million. The net proceeds from the common share offering were used to purchase an additional 9,200,000 common limited partnership units of CPLP. CPLP used the funds to repay a portion of the indebtedness outstanding under its credit facilities, which was drawn to fund the acquisitions of the New England facilities described below, and for general corporate purposes including financing development projects and working capital requirements.

US$295 million private placement of senior notes

On June 15, 2011, Capital Power U.S. Financing LP, an indirect subsidiary of CPLP, announced that it had closed a US$295 million private placement of senior notes. The net proceeds from the transaction were used to repay a portion of the debt outstanding under its credit facilities, which was drawn to fund the acquisitions of the New England facilities described below, and for general corporate purposes.

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

Acquisition of Halkirk Wind Project

In June 2011, CPLP announced that it had acquired 100% of Halkirk I Wind Project LP and Halkirk I Wind Project Ltd. from Greengate Power Corporation for $33 million. The assets of the acquired entities were comprised of intangible assets including various permits and land lease rights required to construct the Halkirk Wind Project (Halkirk), and a 20-year purchase and sale agreement for the sale of renewable energy credits to a third party. Halkirk is a 150-MW wind farm located in east central Alberta, which Capital Power will build, own and operate. All approvals and permits from the Alberta Utilities Commission (AUC) and Alberta Environment are in place for the Capital Power facility. The AUC permit for the high voltage transmission and substation interconnection is expected in the first quarter of 2012.

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

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

Acquisition of three New England power plants

On April 28, 2011, CPLP acquired 100% of the equity interests in Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport), for $346 million (US$363 million) including a working capital adjustment of $8 million (US$8 million). Bridgeport is a natural gas-fired combined cycle power generation plant located in Bridgeport, Connecticut, with a net winter capacity of 540 MW.

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

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

$300 million debt offering

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

$232 million common share offering

In March 2011, the Company issued and sold 9,315,000 common shares at a price of $24.90 per share to a syndicate of underwriters for gross proceeds of $232 million less issue costs of $9 million. The net proceeds from the common share offering were used to repay a portion of the outstanding indebtedness under the Company's credit facilities.

Subsequent Events

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

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

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

Plant Summary

	Energy source	Year ended December 31 2011 Electricity generation (GWh) [1]	2010	2011 Plant availability (%) [2]	2010	2011 Plant revenues (unaudited, $millions) [3]	2010
Total electricity generation, average plant availability and total plant revenues excluding acquired Sundance PPA and CPILP plants		13,659	9,205	92%	90%	$ 867	$ 465
Alberta commercial plants and acquired Sundance PPA							
Genesee 3	Coal	1,677	1,662	85%	88%	$ 126	$ 84
Keephills 3 [4]	Coal	871	-	99%	-	50	-
Joffre	Natural gas	349	283	92%	95%	61	36
Clover Bar Energy Centre 1, 2 and 3	Natural gas	391	361	80%	71%	75	43
Taylor Coulee Chute [5]	Water flows	16	11	98%	97%	2	1
Clover Bar Landfill Gas	Landfill gas	33	38	86%	93%	3	2
Alberta commercial plants - owned		3,337	2,355	87%	84%	317	166
Acquired Sundance PPA	Coal	2,600	2,908	86%	93%	181	146
		5,937	5,263	87%	87%	$ 498	$ 312
Alberta contracted plants							
Genesee 1	Coal	3,127	3,288	93%	100%		
Genesee 2	Coal	3,314	3,046	100%	92%		
		6,441	6,334	97%	96%	$ 314	$ 278
Ontario and British Columbia contracted plants							
Kingsbridge 1	Wind	102	105	99%	99%	$ 7	$ 6
Miller Creek	Water flows	88	95	87%	60%	2	3
Brown Lake	Water flows	51	43	86%	97%	4	3
Island Generation [6]	Natural gas	108	273	100%	99%	38	9
		349	516	98%	90%	$ 51	$ 21
North East U.S. commercial plants [7]							
Bridgeport	Natural gas	2,016	-	81%	-	$ 96	$ -
Rumford	Natural gas	321	-	95%	-	22	-
Tiverton	Natural gas	1,100	-	94%	-	53	-
		3,437	-	88%	-	$ 171	$ -
North Carolina U.S. contracted plants [8]							
Roxboro	Mixed [9]	36	-	100%	-	$ 5	$ -
Southport	Mixed [9]	59	-	100%	-	9	-
		95	-	100%	-	$ 14	$ -
CPILP plants [10]	Various	4,015	5,013	93%	95%	$ 444	$ 521

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

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

(3) In this summary, plant revenue represents revenue generated directly from plant activity and does not include portfolio or mark-to-market generated revenue.

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

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

(6) Island Generation was acquired effective October 19, 2010.

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

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

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

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

The Company's owned Alberta commercial generation fleet includes two supercritical-coal facilities, two natural gas-fired facilities and one landfill-gas facility with a total gross generating capacity of 1,739 MW (946 MW net ownership interest). In 2011, construction on the Keephills 3 unit, under joint venture with TransAlta, was completed. Commercial production commenced on September 1, 2011 adding 247 MW of generating capacity to the Company's existing fleet. In November 2011, the Company sold its interest in the 13 MW Taylor Coulee Chute hydro plant.

The Alberta commercial plants and portfolio optimization category also includes the Company's 52% ownership in the acquired Sundance PPA which has a committed capacity for Sundance Units 5 and 6 equal to 710 MW. This PPA was purchased in August 2000 and expires on December 31, 2020. In addition to earning pool receipt revenues and incurring its share of certain variable and fixed costs, the Company can earn penalty payment revenue or incur availability incentive payments which are a function of plant performance and a 30-day rolling average power price.

Alberta contracted plants comprises the Genesee 1 and 2 generation facilities; their capacity and output are sold under a long-term PPA with the Alberta Balancing Pool which expires at the end of 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 plant availability. The Company seeks to maximize earnings for contracted plants by achieving high availability and managing costs within the PPA terms.

Ontario and British Columbia contracted plants comprises the Kingsbridge 1 wind farm in Ontario and the Brown Lake and Miller Creek hydro facilities and the natural gas–fired Island Generation plant in British Columbia. Revenues from the Miller Creek and Brown Lake facilities are earned under contracts with BC Hydro and consist of sales calculated based on a contracted price per actual MWh generated. Miller Creek's price is based on the hourly Mid-C price. Brown Lake's price is based on a fixed amount escalated by 3% annually. Under the terms of the Company's PPA with BC Hydro, Island Generation earns revenue based on deemed generation. Deemed generation is based on deemed availability being the availability of the plant for dispatch. The actual dispatch strategy is determined by BC Hydro and does not affect the Company's revenues. The plant's maintenance costs are primarily based on equivalent operating hours and are a function of actual generation.

North East U.S. commercial plants and portfolio optimization consist of generation facilities for which the Company has not contracted their power and capacity to third parties. This category is a networked hub and includes the Company's directly-owned facilities located in New England, U.S. consisting of the Bridgeport, Rumford and Tiverton facilities acquired in April 2011 as described in Significant Events. The output of the plants is sold by the Company to the New England Power Pool (NEPOOL).

North Carolina U.S contracted plants include the Roxboro and Southport facilities acquired in November 2011, as described under Significant Events. Revenues from these plants are earned under PPAs with Progress Energy which expire in 2021. Under the PPAs, Progress Energy 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 these contracted plants by achieving high availability of the plants and managing costs within the PPA terms.

In this MD&A, the CPILP facilities are discussed on a combined basis rather than individually unless otherwise stated. During the period that the Company indirectly owned CPILP, the CPILP fleet consisted of 20 facilities located in Canada and the U.S. with PPAs and fuel supply contracts that provided stable cash flows.

Portfolio Optimization

Capital Power's commodity portfolio is comprised of generation assets, customer positions and trading positions. All commodity risk management and optimization activities are centrally managed by Capital Power's commodity portfolio management group. Portfolio optimization includes activities undertaken to manage Capital Power's exposure to commodity risk and enhance earnings. Overall commodity exposure within the portfolio is managed within limits established under Capital Power's risk management policies.

Capital Power manages its output from its commercial plants, contracted plants with residual commodity exposure and acquired PPAs under its networked hub strategy. Capital Power sells and/or buys physical and/or financial forward contracts that are generally non-unit specific, reducing exposure to plant specific availabilities.

Capital Power also takes specific and limited positions in the electricity, natural gas, and emission markets outside of the Alberta and U.S. Northeast regions to develop capability to support Capital Power's growth strategy and to generate trading profits.

Capital Power's commodity portfolio team performs the following functions:

- Manages price and volume risk in Capital Power's commodity portfolio;
- Sets the generation unit offer strategy for electricity, capacity and ancillary services in order to optimize returns while managing potential exposure arising from generation and transmission risks, including unplanned outages;
- Acquires and schedules deliveries of natural gas supplies used to generate electricity;
- Derives earnings from wholesale trading of electricity, natural gas and emissions products in all deregulated North America markets, with the exception of Electric Reliability Council of Texas;
- Ensures compliance with existing and emerging market-based environmental regulations such as the GHG offset investments and purchases that are designed to proactively manage potential compliance risks and costs associated with GHG regulations; and
- Explores and researches electricity, natural gas and emissions markets to ensure preparedness for effective commodity portfolio management of Capital Power's growing commodity portfolio.

Capital Power controls its trading activities by measuring and reporting portfolio risk, validating transactions, valuing the portfolio and managing and reporting credit exposures. Capital Power uses mark-to-market valuation and Value-at-Risk (VaR) techniques to assess the risk of its commodity portfolio. 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 utilizes historical data and back testing to assess market risk arising from possible future changes in commodity prices over the holding period. Capital Power actively manages the aggregate VaR exposure of its commodity portfolio within approved limits as set out in Capital Power's risk management policies.

North East U.S. portfolio optimization includes electricity trading in the eastern Canada and North East U.S. markets. Other portfolio activities include natural gas trading in North American markets and electricity trading in the Pacific North West U.S. markets. The Company also holds retail and commercial natural gas customer contracts in Alberta but 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.

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

(unaudited)	**Unit**	**2011**	**2010**
Alberta portfolio			
Hedged position [1]	% sold forward at beginning of year	73	90
Realized power price [2]	$/MWh	68	66
Spot power price	$/MWh	76	51
North East U.S portfolio			
Hedged position	Approximate average % contracted throughout period	55	-

(1) Hedged position is for the Alberta baseload plants and acquired Sundance PPA.

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

Consolidated Net Income

The primary factors contributing to the change in net income for the year ended December, 31, 2011 compared with the year ended December 31, 2010 are presented below; a detailed analysis of these items can be found in the Results by Plant Category and Other and the Consolidated Other Expenses and Non-controlling Interests sections.

(unaudited, $millions)	
Consolidated net income for year ended December 31, 2010	**$ 77**
Increase in gains on acquisitions and disposals	63
Increase in EBITDA due to acquisitions of North East U.S., North Carolina U.S. and Island Generation plants	56
Increase in EBITDA for Alberta plants and portfolio due primarily to higher power prices	53
Decrease in impairment losses	22
Decrease in depreciation and amortization expense	12
Increase in net unrealized losses on fair value adjustments of derivative instruments, natural gas inventory held for trading, investment in Atlantic Power, and forward bond sale contracts	(19)
Increase in interest expense excluding unrealized gains or losses	(19)
Increase in realized loss on foreign exchange and forward bond sale contracts settled in 2011	(20)
Decrease in EBITDA for CPILP plants	(27)
Other	4
Increase in income before tax	125
Increase (decrease) in income tax	(14)
Increase in net income	**111**
Consolidated net income for the year ended December 31, 2011	**$ 188**

Results by Plant Category and Other

The Company reports results of operations in the following categories: (i) Alberta commercial plants, acquired Sundance PPA and portfolio optimization, (ii) Alberta contracted plants, (iii) Ontario and British Columbia contracted plants, (iv) North East U.S. commercial plants and portfolio optimization, (v) North Carolina U.S. contracted plants, (vi) CPILP plants, (vii) Other portfolio activities, and (viii) Corporate.

Financial results

(unaudited, $millions)	Year ended December 31	
	2011	**2010**
Revenues and other income		
Alberta commercial plants, acquired Sundance PPA and portfolio optimization [1]	$ 793	$ 915
Alberta contracted plants	314	278
Ontario and British Columbia contracted plants	51	21
North East U.S. commercial plants and portfolio optimization [2]	173	-
North Carolina U.S. contracted plants [3]	14	-
CPILP plants	447	525
Other portfolio activities	92	106
Corporate	22	27
Interplant category transaction eliminations	(64)	(63)
	1,842	1,809
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments, and natural gas held for trading	(62)	(55)
Unrealized changes in fair value of CPILP's foreign exchange contracts	(10)	8
	(72)	(47)
	$1,770	**$1,762**
EBITDA [4]		
Alberta commercial plants and portfolio optimization [1]	$ 224	$ 201
Alberta contracted plants	190	160
Ontario and British Columbia contracted plants	38	13
North East U.S. commercial plants and portfolio optimization [2]	26	-
North Carolina U.S. contracted plants [3]	4	-
CPILP plants	148	174
Other portfolio activities	8	-
Corporate	(105)	(103)
Interplant category transaction eliminations	-	(1)
	533	444
Unrealized changes in fair value of CPLP's energy and foreign exchange derivative instruments and natural gas held for trading	(39)	(26)
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	(9)	-
	(48)	(26)
	$ 485	**$ 418**

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

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

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

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

Spot price averages	Year ended December 31 2011	2010
Alberta power ($/MWh)	76	51
New England mass hub (US$/MWh) (1)	43	n/a
Alberta natural gas (AECO) ($/Gj) (2)	3.44	3.79

(1) New England mass hub average price from April 2011, when the New England plants were acquired, to December 31, 2011.

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

Alberta commercial plants, acquired Sundance PPA and portfolio optimization

Alberta commercial plants, acquired Sundance PPA and portfolio optimization (1)	Year ended December 31 2011	2010
Electricity generation (GWh)	5,937	5,263
Availability (%)	87	87
Revenues (unaudited, $millions)	793	915
EBITDA (unaudited, $millions) (2)	224	201

(1) Alberta commercial plants, acquired Sundance PPA and portfolio optimization includes the Company's interest in the acquired Sundance PPA.

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

Alberta commercial plants, acquired Sundance PPA and portfolio optimization comprises the Company's interests in Alberta merchant facilities including the Company's interest in the acquired Sundance PPA and trading activities in the Alberta market.

For the year ended December 31, 2011, production increased 674 GWh compared with the corresponding period of 2010 primarily due to the addition of Keephills 3 and increased opportunities to dispatch the Company's Alberta based peaking and mid-merit plants (CBEC and Joffre), as a result of higher average Alberta power prices. Overall availability was consistent compared with the prior year primarily due to increased availability from CBEC offset by the unfavourable impact of outages at Genesee 3 and Sundance units 5 and 6. The CBEC units were unavailable for a combined total 160 days in 2011 compared with 231 days during 2010. In both years unit outages were due to the need for mechanical repairs. Genesee 3 went offline on November 11, 2011 and returned to service on January 15, 2012. The unit went offline due to an electrical design issue that resulted in damage to the turbine/generator bearings and rotor. Sundance Unit 6 went offline on August 18, 2011 due to a transformer failure and remained offline until October 14, 2011 for planned maintenance. There were no significant outages at the Sundance units for the year ended December 31, 2010.

Alberta spot prices experienced higher volatility than prior years due to a tighter supply demand balance. The average Alberta power spot price was $76/MWh for the year ended December 31, 2011 compared with $51/MWh in 2010. The higher average spot price for the year ended December 31, 2011 was primarily driven by several unplanned coal outages throughout the year and increased demand for power.

For the year ended December 31, 2011, lower revenues compared with 2010 primarily reflected the expiry of the Company's RRT contracts with EPCOR and the impact of periods of high Alberta power prices on the Company's derivative sell contracts. Lower revenues related to the termination of the Company's contracts with EPCOR were almost completely offset by lower costs from the termination of these contracts making the EBITDA impact immaterial. Lower revenues were partly offset by the addition of Keephills 3 in September 2011 and increased opportunities to dispatch Joffre and CBEC.

The favorable EBITDA for the year ended December 31, 2011 compared with 2010 was primarily driven by a combination of the impact of higher Alberta power prices on Alberta commercial plants, the addition of Keephills 3 and the portfolio optimization strategies employed by the Company. In the year ended December 31, 2011, the Company positioned the portfolio with enough length to take advantage of volatile market conditions.

Alberta contracted plants

Alberta contracted plants	Year ended December 31 2011	2010
Electricity generation (GWh)	6,441	6,334
Availability (%)	97	96
Revenues (unaudited, $millions)	314	278
EBITDA (unaudited, $millions) (1)	190	160

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

The Genesee station achieved strong availability and generation for the years ended December 31, 2011 and 2010. Genesee Unit 2 had a 21-day outage during the second quarter of 2010 and Genesee Unit 1 had a 21-day outage from March 28 to April 18, 2011. Both outages were for scheduled maintenance.

Revenues and EBITDA for Alberta contracted plants were higher for the year ended December 31, 2011 compared with the same period in 2010 primarily due to higher availability incentive revenues. Availability incentive revenues were higher primarily due to the impact of higher rolling average power prices in 2011. Revenues also included lower availability penalties of $5 million incurred during the 21-day scheduled maintenance outage at Genesee 1 compared with $12 million during a similar 21-day scheduled outage at Genesee 2 in 2010. Lower availability penalties during the scheduled outage in 2011 were primarily due to lower rolling average power prices during the outage compared with 2010.

The favourable revenues and EBITDA changes were partly offset by lower capacity payments primarily due to lower 2011 Statistics Canada indices which are an input to the capacity payment calculation. Higher operating expenses for the year ended December 31, 2011, including transmission and power charges for higher production and new initiatives to comply with anticipated environmental requirements, also partly offset the favourable EBITDA change.

Ontario and British Columbia contracted plants

Ontario and British Columbia contracted plants	Year ended December 31 2011	2010
Electricity generation (GWh)	349	516
Availability (%)	98	90
Revenues (unaudited, $millions)	51	21
EBITDA (unaudited, $millions) (1)	38	13

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

For the year ended December 31, 2011, production decreased 167 GWh compared with 2010 primarily due to reduced Island Generation output since the plant was dispatched less during 2011 by BC Hydro. Availability was higher for the year ended December 31, 2011 primarily due to increased availability at the Miller Creek plant. Miller Creek units were off line for a total of 25 days for scheduled maintenance in 2011 compared with 144 days in 2010.

Revenues and EBITDA for the year ended December 31, 2011 were higher than the corresponding period of 2010 primarily due to the acquisition of Island Generation in October 2010.

North East U.S. commercial plants and portfolio optimization

North East U.S. commercial plants (1)	Year ended December 31 2011	2010
Electricity generation (GWh)	3,437	-
Availability (%)	88	-
Revenues (unaudited, $millions)	173	-
EBITDA (unaudited, $millions) (2)	26	-

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

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

The three New England plants contributed $26 million to the Company's EBITDA excluding unrealized changes in the fair value of derivative contracts from May 2011 to December 2011. Since their acquisition in 2011, the results for the North East U.S plants have reflected lower availability and generation than anticipated due to unplanned outages that occurred in the fourth quarter of 2011 which caused higher than expected maintenance work. Power prices and, thus, spark spreads were lower than expected. For the period from acquisition to December 31, 2011, the North East U.S. trading portfolio incurred a net loss due to the impact of low market prices on the overall short position.

North Carolina U.S. contracted plants

	Year ended December 31	
North Carolina U.S contracted plants (1)	**2011**	**2010**
Electricity generation (GWh)	95	-
Availability (%)	100	-
Revenues (unaudited, $millions)	14	-
EBITDA (unaudited, $millions) (2)	4	-

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

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

The results for the North Carolina U.S. plants from their date of acquisition to December 31, 2011 were in line with expectations.

CPILP plants

	Year ended December 31	
CPILP plants (1)	**2011**	**2010**
Electricity generation (GWh)	4,015	5,013
Availability (%)	93	95
Revenues (unaudited, $millions)	447	525
EBITDA (unaudited, $millions) (2)	148	174

(1) The Company disposed of its approximate 29% indirect ownership in CPILP in November 2011.

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

As described in Significant Events, the Company divested its limited partnership units of CPILP in November 2011. The divestiture is the primary reason for lower revenues and EBITDA for the year ended December 31, 2011 which includes results for approximately 10 months compared with a full year in 2010.

Other portfolio activities

	Year ended December 31	
Other portfolio activities	**2011**	**2010**
Revenues (unaudited, millions)	92	106
EBITDA (unaudited, $millions) (1)	8	-

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

See Portfolio Optimization section for description of other portfolio activities.

The decrease in revenues for the year ended December 31, 2011 compared with 2010 was primarily due to the termination of the natural gas storage contract partly offset by higher emission credit sales. In addition, revenues for the year ended December 31, 2010 reflected a gain related to the change in the provision for estimated future losses on certain natural gas retail contracts. EBITDA was higher for the year ended December 31, 2011 compared with 2010 primarily due to higher emission credit sales in 2011 and gains from natural gas trading activities in 2011 compared with losses incurred in 2010.

Corporate

Corporate	Year ended December 31 2011	2010
Revenues (unaudited, $millions)	22	27
EBITDA (unaudited, $millions) [1]	(105)	(103)

[1] The financial results by plant category, except for EBITDA, have been prepared in accordance with GAAP. See Non-GAAP Financial Measures.

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

For the year ended December 31, 2011, Corporate EBITDA reflected higher costs related to increased business development activity and higher employee short-term incentive payments resulting from better 2011 performance against the Company's target metrics. In 2010, costs related to the CPILP strategic review were greater than 2011 and a $7 million obligation to EPCOR was recognized in the third quarter of 2010 for operations and maintenance costs for the Rossdale plant to be incurred over the ten-year period ending in 2019.

Unrealized changes in fair value of energy and foreign exchange derivative instruments, natural gas inventory held for trading and investment in Atlantic Power

Unrealized changes in fair value of energy and foreign exchange derivative instruments, natural gas inventory held for trading and investment in Atlantic Power	Year ended December 31 2011	2010
Revenues (unaudited, $millions)	(72)	(47)
EBITDA (unaudited, $millions) [1]	(48)	(26)

[1] The financial results by plant category, except for EBITDA, have been prepared in accordance with GAAP. See Non-GAAP Financial Measures.

The Company's financial results relating to its Alberta commercial plants and portfolio optimization, North East U.S. commercial plants and portfolio optimization, and other portfolio activities include unrealized changes in the fair value of energy derivative instruments, natural gas inventory held for trading, and the Company's investment in Atlantic Power.

Until the settlement of the Company's derivative instruments used for portfolio optimization purposes, their fair value fluctuations are considered unrealized; upon settlement, the unrealized fair value changes on these instruments are reversed and the gain or loss upon settlement is reflected in the appropriate portfolio optimization category EBITDA.

For the year ended December 31, 2011, unrealized losses of $53 million representing fair value decreases related to the Alberta electricity portfolio were recorded compared with $28 million for the year ended December 31, 2010. The unrealized losses for 2011 resulted from the impact of Alberta forward power prices on the portfolio position and the reversal of unrealized gains representing fair value increases recorded and included in this category in periods prior to the period of reversal. The unrealized losses for 2010 were primarily due to similar reversals of previously recorded unrealized gains. These previously recorded unrealized gains were subsequently realized; at the time of realization, the realized gains were recorded in the results for the Alberta commercial plants category.

Upon acquisition of the New England plants in the second quarter of 2011, the Company began trading in electricity heat rate options surrounding the Bridgeport and Tiverton facilities. Heat rate is the amount of combustible fuel (for example, coal or natural gas) required to produce a unit of electricity. In 2011, the Company recognized fair value increases of $8 million related to its heat rate options included in the North East U.S. portfolio. There was no comparable amount in 2010.

Consideration for the sale of the Company's ownership interest in CPILP included $48 million of stock in Atlantic Power. See Significant Events and Subsequent Events. At December 31, 2011, the fair value of these shares had increased by $5 million. There was no comparable amount in 2010.

Prior to the disposition of the Company's interest in CPILP, the fair value of CPILP's foreign exchange contracts decreased $10 million in 2011 compared with an increase of $8 million for the year ended December 31, 2010. These changes in fair value were primarily due to increases in the forward prices for U.S. dollars relative to Canadian dollars for the period ended November 4, 2011 and decreases for the year ended December 31, 2010.

The fair value of CPILP's natural gas supply contracts that were not designated as hedges for accounting purposes increased $1 million for the year ended December 31, 2011, compared with a decrease of $8 million in 2010. In both years, CPILP designated certain of its natural gas supply contracts as hedges for accounting purposes and the changes in the fair value of these contracts were recorded in other comprehensive income. The unrealized gain in EBITDA in 2011 was primarily the result of the reversal of previously recorded fair value losses on contracts that settled during the period ended November 4, 2011. The unrealized loss in EBITDA for the year ended December 31, 2010 primarily resulted from decreases in forward natural gas prices. The unrealized losses recorded in CPILP's EBITDA for the year ended December 31, 2010 were related to the contracts that were not designated as hedges and resulted from decreases in forward natural gas prices. Although forward natural gas prices decreased for the year ended December 31, 2011, the decreases were smaller and the unrealized losses were offset by the reversal of the previously recorded unrealized losses on contracts that settled in these periods.

Consolidated Other Expenses and Non-controlling Interests

(unaudited, $millions)	Year ended December 31	
	2011	**2010**
Unrealized loss (gain) for changes in fair value of forward bond sale contracts	(2)	(6)
Other finance expense	(103)	(72)
Total finance expense	(105)	(78)
Impairments	(43)	(65)
Gains on acquisitions and disposals	93	30
Foreign exchange loss	(13)	(1)
Depreciation and amortization	(229)	(241)
Income tax recovery	-	14
Net income attributable to non-controlling interests	111	60

Finance expense

In the third quarter of 2011, the Company entered into $200 million of forward bond sale contracts which decreased in fair value by $8 million as of December 31, 2011. This unrealized loss was partly offset by the reversal of an unrealized loss of $6 million recognized in 2010 relating to $200 million of forward bond contracts that were entered into in the second quarter of 2010 and settled in the first quarter of 2011.

Other finance expense for the year ended December 31, 2011 was higher compared with the prior year primarily due to interest on borrowings related to the acquisition of the New England facilities in April 2011. In addition, finance expenses for the year ended December 31, 2011 included a loss of $12 million realized on the settlement of forward bond sale contracts compared with no contract settlements in 2010. The purpose of these contracts was to hedge, on an economic basis, exposure to interest rate risk on anticipated debt issues. The realized loss will be offset by future interest payments incurred at a rate lower than the rate that was locked in by the hedge.

Impairments

For the year ended December 31, 2011, the Company recognized an impairment loss of $43 million related to Capital Power's management and operations agreements with CPILP. The impairment loss was recorded in the second quarter of 2011 as a result of the Company's agreement with Atlantic Power to terminate or assign the contracts in exchange for $10 million. The impairment loss of $65 million for the year ended December 31, 2010 was recognized in the third quarter of 2010 reflecting lower expectations for the availability of waste heat fuel supply at CPILP's Ontario plants.

Gains on acquisitions and disposals

For the year ended December 31, 2011, the Company recognized a pre-tax gain on disposal of CPILP, including the termination of the manager contracts, of $89 million after deducting legal and other disposal costs of $10 million.

For the year ended December 31, 2010, the Company recorded a gain of $28 million on disposal of its final remaining interest in the Battle River Power Syndicate Agreement.

Foreign exchange losses

For the year ended December 31, 2011, foreign exchange losses included an $8 million loss realized on the settlement of foreign exchange contracts. The foreign exchange contracts were entered into in anticipation of U.S. cash payments primarily related to the acquisition of the New England facilities. No material foreign exchange contracts settled in the corresponding period of 2010.

Foreign exchange losses for the year ended December 31, 2011 also included $6 million of foreign currency translation losses primarily related to U.S. dollar denominated debt compared with $1 million in 2010.

Depreciation and amortization

Depreciation and amortization expense was lower for the year ended December 31, 2011 compared with 2010 primarily due to lower depreciation on the CPILP assets as depreciation was not recorded while the CPILP assets were classified as held for sale from June 2011 to November 2011. In addition, depreciation on the Genesee assets decreased as a result of the change in the estimated useful life of the coal plants from 35 years to 45 years effective January 1, 2011. These decreases were partly offset by higher depreciation on the Island Generation, the New England plants, and the North Carolina plants since their acquisitions in October 2010, April 2011 and November 2011, respectively, and depreciation on Keephills 3 since it was commissioned in September 2011.

Income tax expense

Income tax expense was higher for the year ended December 31, 2011 compared with 2010 primarily due to significantly higher taxable income in the current year and lower income attributable to non-controlling interests.

Higher income tax expense in 2011 was partly offset by non-taxable amounts related to the Company's sale of CPILP and income tax recoveries not previously recognized with respect to the Company's acquisition of North Carolina U.S. assets.

Income tax recoveries in 2010 reflected the impact of the enactment of the SIFT legislation on CPILP partly offset by income tax expense related to the Company's review of strategic alternatives for its investment in CPILP. Income tax expense was recorded in the third quarter of 2010 to reflect the tax liability that would result upon the realization of the Company's intention to sell its CPILP partnership units.

Non-controlling interests

Net income attributable to non-controlling interests in CPILP was approximately 71% (2010 - 70%) of CPILP's net income until the disposal of CPILP units on November 5, 2011. Net income attributable to non-controlling interests in CPLP was approximately 49% (2010 - 69%) of CPLP's net income. Net income attributable to non-controlling interests also included the Genesee coal mine partner's share of the consolidated coal costs. The year-over-year increase in non-controlling interests was primarily due to higher net income from CPILP and CPLP in 2011 compared with 2010. CPILP's 2011 net income was higher primarily due to the absence of depreciation on the assets held for sale in the third and fourth quarters of 2011 and impairment losses recognized in the third quarter of 2010. CPLP's net income for 2011 was higher compared with 2010 primarily due to higher EBITDA and the gain on disposal of CPILP partly offset by an impairment loss and higher financing, foreign exchange and depreciation expenses.

The year over year comparability of non-controlling interests was also affected by the disproportionate allocation of certain income items between the non-controlling and controlling interests. Only $30 million of the $89 million gain on disposal of CPILP in 2011 was attributable to non-controlling interests. This outcome was a result of a higher carrying amount for the non-controlling interests' share of the CPILP assets as determined by the purchase price allocation for the acquisition of power generation assets and operations (the Reorganization) from EPCOR on July 9, 2009. Only $4 million of the $43 million impairment loss recognized in 2011 on the Company's management and operations contracts with CPILP was attributable to non-controlling interests as the majority of the contracts based on their carrying amounts were owned by the Company rather than CPLP. Net income attributable to non-controlling interests for the year ended December 31, 2010 included 100% of the gain on sale of the Battle River PPA. The sale had no impact on the net income attributable to common shareholders as their 28% share of the fair value of the Battle River PPA was recognized in the purchase price allocation for the Reorganization.

The net income from CPILP, until the divestiture of the Company's ownership of CPILP units in November 2011, that was attributable to CPLP was approximately 29% (2010 - 30%). Therefore, the net income attributable to non-controlling interests in CPLP included approximately 14% (49% of 29%) of CPILP net income for the year ended December 31, 2011 and 21% (69% of 30%) for the year ended December 31, 2010.

Financial Position

The significant changes in the Consolidated Statements of Financial Position from December 31, 2010 to December 31, 2011 included the acquisitions of the 100 % interests in Bridgeport, Rumford and Tiverton generation facilities and the sale of CPILP units to Atlantic Power as discussed under Significant Events.

(unaudited, $millions)	Year ended December 31			Increase (decrease) due to			
	2011	2010	Increase (decrease)	Acquisitions through business combinations	CPILP disposal	Other	Primary other changes
Trade and other receivables	198	286	(88)	21	(49)	(60)	Primarily due to lower customer energy consumption and the 2011 expiry of customer contracts including the EPCOR rate regulated tariff (RRT) energy supply contract.
Other financial assets - current	53	-	53	-	48	5	Unrealized fair value increase in investment in shares of Atlantic Power.
Intangible assets	296	651	(355)	10	(366)	1	Primarily due to acquisitions including emission credits and permits and land lease rights related to Halkirk partly offset by impairment losses recognized on management and operations contracts and amortization.
Property, plant and equipment	3,842	3,678	164	626	(847)	385	Primarily due to capital expenditures partly offset by depreciation.
Goodwill	46	104	(58)	23	(83)	2	
Net derivative financial instruments assets (liabilities)	(36)	14	(50)	(10)	75	(115)	Primarily due to decreases in the fair value of derivative power contracts affected by increased Alberta forward power prices.
Trade and other payables	220	282	(62)	25	(23)	(64)	Primarily due to lower accruals for energy purchases resulting from lower customer energy consumption and the 2011 expiry of customer contracts including the EPCOR RRT energy supply contract.
Loans and borrowings (including current portion)	1,480	1,869	(389)	-	(724)	335	Primarily due to the $300 million debt offering and US$295 million private placement of senior notes completed during the second quarter of 2011 offset by the $237 million repayment of senior debt payable to EPCOR and the impact of the strengthening U.S. dollar on the translation of the senior notes partly offset by net repayments under credit facilities.
Provisions (including current portion)	230	175	55	-	(54)	109	Primarily due to the recognition of decommissioning provision for the New England and North Carolina U.S. plants.
Share capital	1,499	820	679	-	-	679	Primarily due to the issuance of common shares in March, July and November 2011.
Non-controlling interests	1,072	1,779	(707)	-	(474)	(233)	Non-controlling interests' share of CPLP and CPILP distributions and CPLP's and CPILP's other comprehensive loss, partly offset by non-controlling interests' share of CPLP and CPILP net income and the conversion of CPLP units to common shares by EPCOR in November 2011.

Liquidity and Capital Resources

($millions)	Year ended December 31		
Cash inflows (outflows)	**2011**	**2010**	**Increase (decrease)**
Operating activities	$ 461	$ 391	$ 70
Investing activities	(985)	(483)	(502)
Financing activities	541	99	442

Operating activities

See Funds from Operations.

Investing activities

The year-over-year increase in cash flows used in investing activities primarily reflects the acquisitions of the New England facilities and the Halkirk wind project during the second quarter of 2011 and higher capital spending on the Quality Wind and Port Dover & Nanticoke projects. Cash flows used in investing activities for the year ended December 31, 2011 was partly offset by cash proceeds from the sale of the Company's interest in CPILP as discussed under Significant Events. During the year ended December 31, 2010, cash flows used in investing activities was partly offset by the cash proceeds from the sale of the Battle River PSA.

Financing activities

The cash flows from financing activities during the year ended December 31, 2011 primarily reflected proceeds from the Company's $300 million debt offering in April 2011, US$295 million private placement of senior notes in June 2011, and $232 million and $231 million common share offerings in March and July 2011 (see Significant Events). These cash inflows were partly offset by debt repayments totaling $237 million owing to EPCOR in the second and fourth quarters of 2011. During the year ended December 31, 2010, the Company issued $425 million of debt and $125 million of preferred shares. These cash inflows were partly offset by $247 million of debt repayments primarily to EPCOR which were financed with draws on credit facilities.

On December 31, 2011, CPLP had $1,220 million of credit facilities, of which $868 million remained available as CPLP had $165 million of long-term debt and $187 million of letters of credit outstanding under the facilities. CPLP made a net repayment of $52 million, during the year ended December 31, 2011, under its revolving credit facilities. In addition, Capital Power Corporation had an undrawn bank line of credit of $5 million.

CPLP's available credit facilities will provide it with adequate funding for ongoing development projects and the $28 million of principal debt repayments due in the year ended December 31, 2012.

On June 28, 2011, Standard & Poor's, a division of the McGraw Hill Companies, Inc. (S&P) reaffirmed CPLP's corporate credit rating of BBB but revised its outlook from stable to negative. CPLP has received a long-term debt credit rating of BBB from DBRS Limited (DBRS). The BBB rating assigned by S&P is the fourth highest rating of S&P's ten corporate credit ratings. According to S&P, a BBB corporate credit rating exhibits adequate capacity to meet financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. The BBB rating assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. A BBB rating is an investment grade credit rating, which enhances CPLP's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

Capital expenditures

(unaudited, $millions)	Year ended December 31, 2011	Total project: Incurred to December 31, 2011 (2)	Total project: Total cost estimate (1)	Expected or actual completion date
CPLP				
Keephills 3	$ 57	$ 949	$ 949	3rd quarter 2011
Quality Wind	131	155	455	4th quarter 2012
Halkirk	183	183	357	4th quarter 2012
Port Dover & Nanticoke	24	49	340	4th quarter 2013
Sustaining	92			
Total CPLP	487			
CPILP				
North Carolina plants enhancements	2	93	93	2011
Maintenance capital	19			
Total CPILP	21			
Total capital expenditures (3)	508			
Emission credits	21			
Capitalized interest	(36)			
Net payments to acquire property, plant and equipment and other assets	**$ 493**			

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

(2) Total project capital expenditures incurred to December 31, 2011 reflect capital expenditures incurred since the inception of the project.

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

Keephills 3 commenced commercial operation on September 1, 2011.

2011 capital expenditures for the Quality Wind project were approximately $15 million lower than previously anticipated due to the deferral of certain planned expenditures to 2012. The change is not anticipated to impact the planned completion date of the fourth quarter of 2012 or the total cost of $455 million.

Construction of the Port Dover & Nanticoke project was delayed by completion of the land title transfers and regulatory proceedings, which resulted in $57 million of planned expenditures being deferred to 2012. The delay is not expected to impact the total cost of the project, but the project's completion date has been delayed until the fourth quarter of 2013 pending regulatory proceedings.

In the second quarter of 2011, the Company acquired the Halkirk wind project. The expenditures incurred to date include $33 million for permits and land lease rights, $17 million for distribution and transmission lines, a $124 million payment to the supplier of the wind turbines, and $9 million of other expenditures.

Sustaining capital expenditures include spending on plant maintenance, the Genesee mine, information technology for a new energy trading and risk management system, and leasehold improvements for offices in Calgary and Edmonton.

Future cash requirements

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's estimated cash requirements for 2012 are expected to include approximately $628 million for capital expenditures, approximately $48 million for CPLP distributions to EPCOR (subject to approval by CPLP's Board of Directors), approximately $74 million for Capital Power's common share dividends, and approximately $6 million for quarterly preferred share dividends (subject to approval by Capital Power Corporation's Board of Directors). Effective January 1, 2012, the Company launched a Dividend Re-investment Plan where shareholders may elect to reinvest their quarterly cash dividends for additional shares of Capital Power as an alternative to receiving cash dividends. Accordingly, cash requirements for common share dividends may differ from the above expectations. The cash flow impact of the Dividend Re-investment Plan cannot be estimated until the extent of shareholder participation in the plan is known.

The current portion of loans and borrowings on the statement of financial position of $28 million consists primarily of $25 million payable to EPCOR in the next year.

The Company expects to fund the construction of the Quality Wind, Port Dover & Nanticoke and Halkirk wind projects using existing bank credit facilities. When construction is complete, the Company expects to put long-term financing in place. The Company's other cash requirements identified above, are expected to be funded with cash on hand, cash provided by operating activities, use of existing bank credit facilities, proceeds from the disposition of the interest in CPILP and proceeds from the February 2012 sale of Atlantic Power shares. If there are any further divestitures of hydro facilities, additional funds will be available.

The Company's two short form base shelf prospectuses provide, market conditions permitting, the Company with the ability to obtain new debt and equity capital from external markets when required for a major investment. Under the short form base shelf prospectuses, Capital Power may raise up to $2 billion by issuing common shares, preferred shares, or subscription receipts exchangeable for common shares or other securities of the Company, and up to $1 billion by issuing medium-term notes with maturities of not less than one year. As of the date of this MD&A, Capital Power has approximately $2 billion of equity and $150 million of debt available under these short form base shelf prospectuses.

Financial market stability remains an issue. If instability reoccurred in the Canadian and U.S. financial markets, CPLP's ability to raise new capital, to meet its financial requirements, and to refinance indebtedness under existing credit facilities and debt agreements may be adversely affected. CPLP has credit exposure relating to various agreements, particularly with respect to its PPA, trading and supplier counterparties. While CPLP continues to monitor its exposure to its significant counterparties, there can be no assurance that all counterparties will be able to meet their commitments.

Contractual Obligations

(unaudited, $ millions)	Payments Due by Period						
	2012	2013	2014	2015	2016	Thereafter	Total
Acquired PPA obligations – fixed of capital nature [1]	$ 25	$ 26	$ 27	$ 28	$ 27	$ 101	$ 234
Acquired PPA obligations – variable and other fixed [1]	66	69	69	73	73	325	675
Capital projects [2]	573	455	24	-	-	-	1,052
Energy purchase and transportation contracts [3]	74	19	10	8	8	15	134
Operating and maintenance contracts [4]	3	9	9	9	8	58	96
Environmental credits	20	12	11	11	9	8	71
Operating leases	5	5	5	5	5	64	89
Loans and borrowings	28	19	14	480	145	803	1,489
Interest on loans and borrowings	80	78	76	73	50	173	530
Net commodity contracts-for-differences	55	6	1	-	-	-	62
Decommissioning provisions [5]	1	1	1	2	1	318	324
Other	6	-	-	-	-	-	6
Total	**$ 936**	**$ 699**	**$ 247**	**$ 689**	**$ 326**	**$ 1,865**	**$ 4,762**

(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. Fixed costs of capital nature include depreciation, decommissioning, return on equity, return on debt and working capital.

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

(3) Natural gas transportation contracts are based on estimates subject to changes in regulated rates for transportation and have expiry terms ranging from 2012 to 2017.

(4) 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.

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

Off-Statement of Financial Position Arrangements

As at December 31, 2011, management of the Company does not believe they have any off-statement of financial position arrangements that have, or are reasonably likely to have, a current or future material effect on the Company's financial condition, results of operations, liquidity, capital expenditures or resources.

Transactions with Related Parties

($ millions)		Year ended December 31	
Related party, relationship and transaction	**Note**	**2011**	**2010**
EPCOR (shareholder)			
CPLP distributions paid to EPCOR	(1)	60	71
Purchase of distribution and transmission services from EPCOR	(2)	23	30
Purchase of other services from EPCOR	(2)	7	13
Power sales to EPCOR	(2)	239	370
Interest incurred on unsecured senior debt payable and expensed	(3)	30	7
Interest incurred on unsecured senior debt payable and capitalized	(3)	8	44
Repayment of unsecured senior debt payable	(3)	237	253
Obligation for future maintenance costs associated with Rossdale plant	(4)	7	7
The City of Edmonton (sole shareholder of EPCOR)			
Power sales to the City of Edmonton	(2)	34	29
CPILP (former subsidiary)			
Acquisition of North Carolina assets	(5)	121	-

(1) In November 2011, a subsidiary of EPCOR exchanged a total of 9.2 million of its exchangeable common limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis. Subsequently, EPCOR entered into an agreement for a secondary offering of 9.2 million common shares of Capital Power. As a result, at December 31, 2011, EPCOR owned 38.216 million exchangeable common limited partnership units of CPLP, and 38.216 million accompanying special voting shares and one special limited voting share in the capital of Capital Power Corporation. At December 31, 2010, EPCOR owned 47.416 million exchangeable common limited partnership units of CPLP and 47.416 million accompanying special voting shares and one special limited voting shares of Capital Power Corporation. In connection with EPCOR's shareholdings, CPLP paid distributions to EPCOR for the years ended December 31, 2011 and 2010.

(2) The power sales and purchase of other services transactions with EPCOR and the City of Edmonton were in the normal course of operations and were recorded at the exchange values which were based on normal commercial rates. During the year ended December 31, 2011, the Company entered into a lease agreement with EPCOR for office space. The agreement requires payment to EPCOR of $4 million per year through 2031.

(3) The Company's unsecured senior debt payable to EPCOR was $382 million at December 31, 2011 compared with $619 million at December 31, 2010. This debt 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 common 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. Refer to Liquidity and Capital Resources section for discussion over repayment obligation.

(4) 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 designed as Provincial Historical Resources by the Province of Alberta and are thereby legally protected from demolition. These structures, and additional structures at the plant site, are also on the City of Edmonton's Register of Historic Resources. CPLP has an obligation to EPCOR to share in some of the costs for ongoing operations and maintenance of the Rossdale plant and related assets until 2019.

(5) Refer to Significant Events for discussion of Capital Power's acquisition of the North Carolina assets from CPILP.

Risks and Risk Management

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.

Capital Power has implemented an Enterprise Risk Management Program (ERM Program) to identify, evaluate, report and monitor key risks that may affect the achievement of the Company's strategic and related business objectives. The ERM Program aligns with the International Organization for Standardization's standard for risk management, ISO 31000, and the Company's approach is to undertake risk assessment in conjunction with core corporate processes.

Subject to the oversight of the Board of Directors, risk management is carried out at three levels. First, 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 periodically to review enterprise risk management performance and to evaluate significant or emerging risks. Second, 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. Third, 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; it continually looks for ways to enhance the Company's risk management processes.

Capital Power's principal risk factors could have an adverse impact on the Company's business, prospects, financial condition, results of operations, cash flow, liquidity, capital expenditures, or resources. Not only do these risks provide Capital Power with exposure to negative consequences but also to the possibility that positive consequences will be missed. The identified risk factors are interdependent and the potential impact of any one factor is generally difficult to quantify as the impact of other risk factors changes at the same time or at a subsequent time. These principal risk factors are discussed below:

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 impacted 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 its 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 terms of the PPAs for owned plants and the acquired Sundance PPA provide appropriate incentives to plant owners to keep the plants well maintained and operational. They also provide force majeure protection for high-impact, low-probability events including major equipment failure.

Strategies for managing operations risk

- Execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time for the Company's plants.
- Maintain an inventory of strategic spare parts which can reduce down time in the event of failure.
- Participate in a leased engine program for the LMS 100 units at CBEC to reduce down time by replacing a failed unit with a leased unit provided by the manufacturer.
- Establish appropriate business interruption and property and boiler insurance to reduce the impact of prolonged outages caused by insured events.

Electricity price and volume risk

The market price for electricity, in the jurisdictions and markets in which Capital Power operates, affects Capital Power's revenues. 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 environmental and other regulatory requirements, the structure of the particular market, and weather conditions. It is not possible to predict future electricity prices with 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. 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% interests in Genesee 3 and Keephills 3 are not covered by long-term commercial contracts, the units are baseload coal-fired generating plants with relatively low variable costs and generally run when they are available. For the Company's Genesee 3, Keephills 3, CBEC and Joffre plants, the acquired Sundance PPA plant, and the Company's North East U.S commercial facilities, electricity spot prices, the plants' variable costs, and planned and unplanned outages affect profitability.

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.

Strategies for managing electricity price and volume risk

- Limit exposure to market price volatility by entering into long-term commercial contracts such as those contracts for the Company's Genesee Units 1 and 2, Kingsbridge 1, Miller Creek, Brown Lake, Island Generation, Roxboro and Southport plants.
- Execute Company's growth strategy and re-contract generation plants under new or extended contracts to maintain a balance of contracted and non-contracted plants.
- Minimize exposure to extreme price fluctuations, especially during higher priced peak hour periods. To do this, Capital Power relies on historical load shape data provided by load settlement agents and local distribution companies to anticipate what the 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 electricity if it is short or sell electricity if it is long. Such exposures can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.
- Limit exposure to spot price variability within specified risk limits by entering into various purchase and sale arrangements for periods of varying duration. 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 commodity risk 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.

Environmental risk

Environmental risk encompasses aspects of several different types of risk including political, legislative and regulatory risks, technology risk, physical (such as weather) risks, litigation risk and reputation 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. 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. Further, there can be no assurance that compliance with or changes to environmental regulations will not materially adversely impact Capital Power's business, prospects, financial condition, operations or cash flow.

Strategies for managing environmental risk

- Comply with all applicable laws, regulations and guidelines and monitor compliance by performing environmental compliance audits with corrective actions as necessary.
- Consult with all levels of government with respect to policy development and current and potential legislation.
- Proactive identification of environmental risks within operations, maintenance and construction activities and promote awareness throughout and at all levels of the Company.
- Ensure that contractors align with Capital Power's environmental policies and procedures.

For further discussion of aspects of environmental risks, see rest of Risks and Risk Management section.

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 overpayment 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. These include obtaining government permits and approvals, site agreements, construction contracts, access to power grids, 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 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.

Strategies for managing acquisition and development risk

- Perform detailed project analyses, risk assessments and due diligence prior to and during construction or acquisition.
- Perform post-implementation evaluation of all major acquisition and development projects to improve internal capabilities and processes and to leverage lessons learned for future projects. When necessary, corrective actions are taken to increase the likelihood of investment recovery.
- Enter into favourable long-term contracts for the projects' output, whenever possible.

Political, legislative and regulatory risk

Capital Power is subject to risk associated with changing political conditions and with changes in federal, provincial, state, local or common law and regulations and their interpretation. While it is not possible to predict changes in the legislative and regulatory environment or their impact on the Company's business, income tax status, and operations, there has been an increase in regulatory activity and penalties. Capital Power is also required to maintain numerous licenses, permits and governmental approvals for the operation of its projects and participation in its markets. If Capital Power fails to satisfy the conditions of these instruments, there could be an adverse impact on the effectiveness and cost of those projects or operations. 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. Changes in law and regulatory requirements, such as the Dodd-Frank Wall Street Reform and Consumer Protection Act, may also adversely impact the market dynamics for Capital Power, the participation levels of counterparties that Capital Power relies on to support its portfolio optimization strategies and the costs associated with participating in these markets.

Strategies for managing political, legislative and regulatory risk

- Identify existing, new or changed laws or regulations and prepare appropriate responses or plans.
- Establish positive relationships with all levels of government and stakeholders.

- Execute on-time permitting, license renewals and other activities associated with laws and regulations.

Liquidity risk

Capital Power's ability to fund current and future capital requirements, along with its working capital needs is dependent upon access to financial markets. Uncertainty and volatility in the Canadian and U.S. financial markets may adversely affect Capital Power's ability to access and arrange financing under favourable terms and conditions. The cost of capital will also depend upon prevailing market conditions as well as the business performance of Capital Power. If Capital Power is unable to access sufficient amounts of capital on terms acceptable to Capital Power, it could have an adverse effect on Capital Power's business plan and financial condition.

Strategies for managing liquidity risk:

- Monitor cash and currency requirements on regular basis by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements.
- Meet financing requirements through a combination of committed and demand revolving credit facilities, financings in public and private capital debt markets, and equity offerings.

Derivatives and energy trading risk

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

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

Strategies for managing derivatives and energy trading risk

- Establish and maintain a commodity risk management program which provides the infrastructure to manage commodity and trading risks associated with the commodity business.
- Take market risk positions within authorized limits approved by Capital Power’s executive team and Board of Directors.
- Report daily key risk measures in relation to applicable limits to the executive team with quarterly review by the Board of Directors.
- Perform regular commodity portfolio stress testing to observe the effects of plausible scenarios taking into account historical maximum volatilities and observed price movements.

Fuel supply risk

Capital Power requires energy from sources such as coal, natural gas, water, wind, wood waste and tire derived fuel to generate electricity. A disruption in the supply 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 supply and demand for such fuel supplies, (ii) the quality of the fuel, 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. Most of Capital Power's natural gas-fired plants are operated as merchant facilities and as such are susceptible to the risks associated with the volatility of natural gas prices and the prevailing electricity market prices. Natural gas purchases for these power plants are made under variable price contracts and when facility heat rates do not meet expectations, unit profitability is affected. Island Generation operates under a long term PPA with fuel cost flow-through provisions.

The Company's hydroelectric facilities are dependent upon the availability of water. Variances in water flows may be caused by uncontrollable weather-related factors affecting precipitation. 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.

Strategies for managing fuel supply risk

- Establish long-term supply agreements.
- Maintain coal stock-pile inventories.
- Establish contracts with fuel cost-flow provisions, where possible.

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.

Strategies for managing health and safety risk

- Establish and maintain company-wide health and safety system with regular measurements and compliance audits.

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.

Strategies for managing PPA contract risk

- Measure performance against benchmarks.
- Execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time.

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, although 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.

Strategies for managing Sundance PPA risk

- Work with plant owner to execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time.

Tax risk

Capital Power's operations are complex and the computation of the provision for income taxes involves income 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 its tax filings. Future changes in tax legislation may have an adverse impact on Capital Power, its shareholders and the value of the Company's shares.

The sensitivity of changes in income tax rates upon the Company's net earnings is as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings ($millions)
Tax rate	1	1

The effective income tax rate on normalized earnings before income taxes for 2011 was 26.5%. The effective income tax rate can change depending on the mix of earnings from various jurisdictions, and on deductions and inclusions in determining taxable income that do not fluctuate with earnings.

Strategies for managing tax risk

- Develop and maintain tax expertise and resources necessary to interpret tax legislation.
- Comply with tax laws of jurisdictions that Capital Power operates in.
- Consult with government with respect to policy development and proposed legislation.

Major information technology system implementation risk

In 2011, Capital Power initiated two information technology (IT) implementation projects, one for an Energy Trading and Risk Management system and another for an Enterprise Resource Planning system which are expected to be implemented in 2012 and 2013, respectively. These systems are expected to support the Company's long-term growth strategy since they are planned to provide the flexibility and scalability necessary for Capital Power's growing business. A significant amount of capital and human resources are planned for these projects. Accordingly, existing processes and internal resources will be strained during the implementation periods, which will increase the potential for errors in the related transactions and for failure to successfully implement the new systems on time and on budget.

Strategies for managing major information technology system implementation risk

- Minimize the customization of the associated software, monitor the impacts on processes and internal controls and undertake remedial actions, as required.
- Ensure projects are properly resourced with qualified staff and contractors.

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 other agreements may not be replaceable on similar terms. Capital Power is also dependent upon its cogeneration hosts and suppliers of fuel to its plants. Should a wholesale electricity market counterparty default, Capital Power may not be able to replace such counterparty to effectively 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.

Strategies for managing counterparty risk

- Establish a credit policy including limits for credit risk exposure levels.
- Conduct periodic credit reviews on existing counterparties.
- Use credit enhancements such as cash deposits, prepayments, parent company guarantees, bank letters of credit, master netting agreements, margin account and credit derivatives.
- Monitor and report credit risk exposures.

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, there may be a material adverse effect on Capital Power's ability to sell and deliver wholesale power.

Capital Power's ability to develop new projects is also affected 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.

Strategies for managing reliance on transmission systems risk

- Support the timely development of appropriate transmission capability through active relationships with regulators and government.

Corporate structure risk

The Company is dependent upon cash dividends, distributions or other transfers from its subsidiaries, including CPLP, 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 unitholder 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 of December 31, 20122, the Company has loaned $195 million 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 common limited partnership units.

For as 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.

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 common limited partnership units of CPLP or common shares of the Company. At December 31, 2011, EPCOR's interest in the Company was approximately 39%. EPCOR has advised the Company that it intends to eventually sell all or a substantial number of the common shares underlying its exchangeable common 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.

Strategies for managing corporate structure risk

- Maintain good relationship with EPCOR to ensure that EPCOR continues to act only as an investor in and not as a manager of the Company.

Foreign exchange risk

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.

Strategies for managing reliance on foreign exchange risk.

- Utilize foreign currency forward contracts.
- Contract significant purchases or borrowings in Canadian dollars.
- Utilize U.S. dollar denominated debt to finance U.S. acquisitions and developments.

General economic conditions, business environment and other risks

In addition to all 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, market competition, lawsuits, and risks that are not fully covered by various insurance policies.

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. 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. As identified by ongoing research and development activities, Capital Power's plants may over time be unable to compete with newer more efficient plants utilizing improvements to existing power technologies and cost-efficient 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.

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 storm and other weather conditions and natural disasters.

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.

The Company considers reputation risk to be a consequence of all other risks that it faces. If a certain risk factor results in positive or negative consequences to the Company, its reputation may also be positively or negatively affected. In part, the Company manages it reputation risk by employing appropriate risk management strategies for all identified risks.

Capital Power's property, business interruption and liability insurance coverages are 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.

Strategies for managing other risks

- Establish and maintain good human resource practices including monitoring developments.
- Conduct ongoing research and development activities to improve upon existing power technologies and reduce the cost of power generation.
- Establish and maintain security measures to mitigate the risk related to loss of data due to theft or corruption and system recovery programs to minimize any losses experienced as a result of a computer application system shutdown.
- Establish and maintain insurance programs to minimize financial exposures associated with extreme weather and other events.
- Establish and maintain emergency and other related contingency planning measures to enable the timely response to and recovery from extreme weather and other events.

Environmental Contractual Obligations

The Company has recorded decommissioning provisions of $157 million as at December 31, 2011 for its generation plants and the Genesee coal mine as it is obliged to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. Decommissioning provisions for the coal mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

The Company is obligated to purchase environmental credits totaling approximately $71 million in future years and expects to use these credits to comply with certain environmental regulations.

Critical Accounting Estimates and Accounting Judgments

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the Company's critical accounting estimates which make assumptions about matters that are highly uncertain at the time the accounting estimate is made or period-to-period changes in the estimate would have a material impact on financial condition, changes in financial condition or financial performance.

Financial instruments

The Company is required to estimate the fair value of certain assets and obligations for determining the valuation of derivative instruments and certain other financial instruments.

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. When traded markets are not considered to be sufficiently active or do not exist, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates and maximize, when available, the use of external readily observable market data including future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rates, counterparty credit risk, the Company's own credit risk, and volatility. 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.

Non-financial assets

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

In the first quarter of 2011, management performed a review of the useful life of the Company's coal plants and determined that the useful life did not match common industry practices. As a result of an analysis compared with industry peers, historical averages, and the Company's maintenance practices, the estimate of the useful life of the coal plants was revised. Effective January 1, 2011, the Company prospectively revised its estimate of the useful life of its coal plants from 35 years to 45 years. The change in estimate resulted in lower depreciation expense for the year ended December 31, 2011.

For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the cash generating units (CGU) that are expected to benefit from the acquisition.

Estimates of fair value for the recoverable amount of CGUs undergoing impairment testing, and for purchase price allocations for business combinations are primarily based on discounted cash flow projections techniques employing estimated future cash flows based on assumptions regarding the expected market outlook and cash flows from each CGU or asset. The cash flow estimates will vary with the circumstances of the particular assets or CGU and will be based on, among other things, the lives of the assets, contract prices, estimated future prices, revenues and expenses, including growth rates and inflation, and required capital expenditures.

For purposes of impairment testing of non-financial assets, assets that are managed as a portfolio are grouped together into a CGU, which is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purpose of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination.

The Company has determined its CGUs and for non-financial assets subject to depreciation and amortization, it performs impairment testing when events or changes in circumstances may indicate or cause the asset's carrying amount to exceed its recoverable amount. The Company reviews the recoverability of goodwill and indefinite life intangibles on an annual basis, or more frequently if events or circumstances indicate that the carrying amount may be impaired.

Identifying events or changes in circumstances that may indicate or cause a non-financial asset's carrying amount to exceed its recoverable amount requires judgment in assessing what events or circumstances would have such an impact. For the year ended December 31, 2011, the Company recognized an impairment loss of $43 million on management contracts associated with the operations of CPILP prior to the sale of CPILP units to Atlantic Power.

Decommissioning and other provisions

Measurement of the Company's provisions and the related change in discount rate require 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 for the decommissioning provisions and estimates of expected customer renewals for the Company's other provisions.

The Company estimates the undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $324 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2012 and 2084, which reflects the anticipated useful lives of the different power plants. The majority of the payments to settle the obligations are expected to occur between 2032 and 2066 for the power generation plants and between 2012 and 2019 for sections of the Genesee coal mine. Discount rates used to calculate the carrying amount of the obligation ranged from 0.95% to 2.89%. The actual costs to settle decommissioning obligations may vary from estimates as a result of changes to contractor rates required to perform the decommissioning.

The Company holds retail and commercial natural gas customer contracts in Alberta, acquired as part of the July 1, 2009 acquisition of assets from EPCOR. The future unavoidable costs of meeting the terms of these contracts are expected to exceed the economic benefits to be received under these contracts. As a result, a provision has been recorded to reflect the estimated present value of the loss on these contracts. The expected timing of settlement of these contracts range from 2012 to 2046 and the costs were discounted using risk free rates between 0.5% and 2.4%. The timing and settlement of the obligation is dependent on expectations or renewal of the contracts and expectations of the forward price of natural gas.

Income taxes

Income taxes are determined based on estimates of the Company's current income taxes and estimates of deferred income taxes resulting from temporary tax differences. Deferred tax assets are assessed to determine the likelihood that they will be realized from future taxable income.

Revenue recognition

Estimates of the value of electricity and natural gas consumed by customers but not billed until subsequent to period-end are based on volume data provided by the parties responsible for delivering the commodity and contracted prices. Actual results may differ from these estimates with adjustments to previous estimates being recorded in the period that they become known.

Leases or arrangements containing a lease

The Company has exercised judgment in determining whether the risks and rewards of its generation assets which are subject to a PPA are transferred to the contracted purchaser under the PPA, in determining whether a lease exists and if so, whether the lease should be treated as a finance or operating lease.

The PPA under which the Company's Kingsbridge1 power generation facility operates is accounted for as a finance lease.

For other power generation plants operating under PPAs, their assets are accounted for as assets under operating leases.

Transition to IFRS and Impact on Accounting Policies

Capital Power's December 31, 2011 consolidated financial statements were prepared in accordance with GAAP which is based on IFRS. The comparative information for the year ended December 31, 2010 has been restated based on the application of IFRS 1 - *First-time Adoption of International Financial Reporting Standards*. The Company's previously issued interim and financial reports, for periods prior to and including the year ended December 31, 2010, were prepared in accordance with previous CGAAP.

IFRS 1 provided that first time adopters could make certain elections that would provide exemption from retrospectively adopting certain IFRS. The following elections were significant to Capital Power as of the transition date of January 1, 2010:

- The Company elected to use fair value as the deemed cost of its property, plant and equipment for certain plants.
- The Company elected not to retrospectively apply the IFRS standards requiring that non-controlling interests be recognized at fair value on acquisition or at the non-controlling interests' share of the amounts recognized for the acquisition excluding goodwill to the acquisition of power generation assets and operations from EPCOR in June 2009.
- The Company elected to deem any cumulative translation amounts to be nil as of the transition date and reclassified the previous balance to retained earnings with no impact on the statement of income.

The revised standards required certain changes in accounting policies resulting in adjustments to the Company's balance sheet as of the transition date and for future periods. Those changes that significantly affected Capital Power were:

- Certain spare parts that no longer meet the capitalization criteria now are being directly expensed.

- The Kingsbridge 1 PPA is considered to be finance lease for accounting purposes which reduced property, plant and equipment and increases finance lease receivable.

In periods subsequent to the date of transition, Capital Power expects that the adoption of IFRS will have the following impacts relative to previous CGAAP:

- Impairment of assets standards will result in more frequent write-downs of goodwill and long-lived assets.
- Changes to the calculation of capitalized borrowing costs will result in decreased finance expense.
- The componentization of property, plant and equipment at a more detailed level and the increase in decommissioning assets will result in increased depreciation expense

Future Accounting Changes

The following new and amended standards will be effective in future periods as indicated and may have an impact on Capital Power's financial statements. The Company is currently assessing the impact of adopting these standards and amendments on its consolidated financial statements. For those standards where earlier application is permitted, Capital Power expects to apply the changes at the effective date.

IAS 1 – *Presentation of Financial Statements* – In June 2011, the International Accounting Standards Board (IASB) issued amendments to IAS 1 which will require entities to group items within other comprehensive income on the basis of whether or not they will be reclassified to profit or loss in a future period. The implications of adopting the amendments to IAS 1 will be limited to the Company's presentation within its statement of other comprehensive income. The amendments are effective for annual periods beginning on or after July 1, 2012 and are to be applied retrospectively. Earlier application is permitted.

IFRS 7 – *Financial Instruments: Disclosures* – In December 2011, the IASB issued amendments to IFRS 7 which establishes enhanced disclosure requirements for offsetting financial assets and liabilities. The implications of adopting the amendments to IFRS 7 will result in additional disclosure to the Company's consolidated financial statements. The amendments are effective for annual periods beginning on or after January 1, 2013 and are to be applied retrospectively. Earlier application is permitted.

IFRS 10 – *Consolidated Financial Statements* – In May 2011, the IASB issued IFRS 10 which replaces IAS 27 – *Consolidated and Separate Financial Statements* and SIC 12 - *Consolidation* – *Special Purpose Entities*. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. The new standard provides a revised definition of control and a single consolidation model as the basis for consolidation for all types of entities. The standard also provides additional guidance to assist in the determination of control. Capital Power does not expect that the adoption of this new standard will have a material effect on the consolidated financial statements, as application of the new definition of control does not change the Company's current accounting treatment for entities in which it holds an interest in. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 11 and IFRS 12.

IFRS 11 – *Joint Arrangements* – IFRS 11 was issued in May 2011 and supersedes IAS 31 – *Interests in Joint Ventures* and SIC 13 – *Jointly Controlled Entities – Non-Monetary Contributions by Venturers*. The standard classifies joint arrangements as joint operations or joint ventures. Joint operations are arrangements where the owners directly own a share of the individual assets and are directly responsible for contributing a share of the individual liabilities of the joint arrangement. The owners will account for its share of the arrangement using the proportionate consolidation method. Joint ventures are arrangements where the arrangement itself directly owns the assets and is directly responsible for the liabilities of the arrangement. IFRS 11 eliminated the choice to account for joint ventures using the proportionate consolidation method and instead requires the equity method of accounting. The Company does not expect that the adoption of this new standard will have a material effect on the consolidated financial statements, as it is substantially aligned with the Company's current practice. IFRS 11 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 10 and IFRS 12.

IFRS 12 – *Disclosures of Interests in Other Entities* – In May 2011, the IASB issued IFRS 12, a new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. IFRS 12 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively and will result in additional disclosure to the Company's consolidated financial statements. Earlier application is permitted but must be applied simultaneously with IFRS 11 and IFRS 10.

IFRS 13 – *Fair value Measurement* – In May 2011, the IASB issued IFRS 13 which defines fair value, sets out in a single IFRS a framework for measuring fair value and enhances disclosures about fair value measurements. IFRS 13 applies to fair value measurements required or permitted by other IFRSs, but does not (a) introduce any new requirements to measure an asset or a liability at fair value, (b) change what is measured at fair value in

IFRSs, or (c) address how to present changes in fair value. The implications of adopting this new standard will be limited to the Company's fair value disclosures for financial instruments and asset impairment calculations. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and is to be applied prospectively. Earlier application is permitted.

IAS 19 – *Employee Benefits* – In June 2011, the IASB issued an amendment to IAS 19 which introduced changes related to: (a) eliminating the option to defer the recognition of actuarial gains and losses, known as the corridor method, (b) requiring a new method of calculating finance costs on defined benefit plans where a single discount rate is applied to the net pension assets or obligations, and (c) enhancing the disclosure requirements to provide better information about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. Capital Power expects that the new method of calculating finance costs will lower the Company's net earnings, as the expected return on assets is currently higher than the obligation discount rate. The extent of the financial impact is expected to be immaterial. Amendments to IAS 19 are effective for annual periods beginning on or after January 1, 2013 and are to be applied retrospectively. Earlier application is permitted.

International Financial Reporting Standards Interpretations Committee (IFRIC) 20 – *Stripping Costs in the Production Phase of a Surface Mine* – In October 2011, the IASB issued an interpretation which clarifies the accounting requirement for waste removal costs incurred in the production phase of a surface mine (stripping costs). IFRIC 20 addresses (a) when stripping costs are recognized as an asset, (b) where the costs should be classified on the statement of financial position, and (c) the initial and subsequent measurement of the asset. The Company does not expect that the adoption of this interpretation will have a material effect on the consolidated financial statements, as it is substantially aligned with the Company's current policies. This interpretation is effective for annual periods beginning on or after January 1, 2013 and is to be applied prospectively. Earlier application of the interpretation is permitted.

IAS 32 – *Financial Instruments: Presentation* – In December 2011, the IASB issued amendments to IAS 32 which clarifies the criteria for offsetting financial assets and liabilities. Capital Power does not expect that the adoption of the amendments will have a material effect on the consolidated financial statements, as they are substantially aligned with the Company's current policies. The amendments are effective for annual periods beginning on or after January 1, 2014 and are to be applied retrospectively. Earlier application is permitted.

IFRS 9 – *Financial Instruments* – In November 2009, the IASB issued IFRS 9 – *Financial Instruments* which addresses the classification and measurement requirements of financial assets. The standard was amended in October 2010 to include the requirements for the classification and measurement of financial liabilities. The changes are effective for annual periods beginning on or after January 1, 2015 and are to be applied retrospectively. Earlier application is permitted.

Financial Instruments

The Company has various financial assets that are classified for financial reporting purposes as available for sale, held at fair value through income or loss, or loans and receivable. Financial liabilities are classified as either held at fair value through income or loss or other liabilities. Initially, all financial assets and financial liabilities are recorded on the statement of financial position at fair value with subsequent measurement determined by the classification of each financial asset and liability.

The Company classifies its cash and cash equivalents as loans and receivables, and its current and non-current derivative financial instruments assets and liabilities as held at fair value through income or loss. Trade and other receivables are classified as loans and receivables and trade and other payables are classified as other liabilities. Trade and other receivables and trade and other payables 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 amounts and fair values of other financial instruments held at December 31, 2011 and 2010 were as follows:

($millions)	As at December 31, 2011		As at December 31, 2010	
	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets				
Loans and receivables	$ 38	$ 37	$ 54	$ 52
Financial assets designated at fair value through income or loss	53	53	-	-
Finance lease receivable				
Loans and receivables	58	50	85	75
Other financial liabilities				
Loans and borrowings (including current portion)	1,480	1,571	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 statement of financial position 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.

Unrealized changes in the fair value of financial and non-financial derivatives that do not qualify for hedge accounting and non-financial derivatives that do not qualify for the expected purchase, sale or usage requirements of the contract are recognized in revenues or energy purchases and 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, foreign 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 statement of financial position 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.

The derivative instruments assets and liabilities held at December 31, 2011 as compared with 2010 and used for risk management purposes were measured at fair value and consisted of the following:

($millions)	Energy cash flow hedges	Energy non-hedges	Foreign exchange non-hedges	Interest rate non-hedges	Total
Derivative instruments net assets (liabilities) as at December 31, 2011	$ (23)	$ (5)	$ -	$ (8)	$ (36)
Derivative instruments net assets (liabilities) as at December 31, 2010	(57)	44	33	(6)	14

Energy derivatives designated as accounting hedges

At December 31, 2011, the fair value of the energy derivative instruments designated and qualifying for hedge accounting was a net liability of $23 million, a decrease from the net liability of $57 million at December 31, 2010. The decrease in the net liability primarily reflects the impact of increased forward Alberta power prices on power derivative contracts relative to the contract prices. Unrealized gains and losses for fair value changes on derivatives that qualify for hedge accounting are recorded in other comprehensive income and reclassified to net income as revenues or energy purchases and fuel, as appropriate, when realized.

Derivatives not designated as accounting hedges

At December 31, 2011, the fair value of energy derivative instruments not designated as hedges for accounting purposes was a net liability of $5 million as compared with a net asset of $44 million at December 31, 2010. The difference primarily reflected the impact of changes in the forward Alberta power prices on the Alberta power portfolio. Unrealized and realized gains and losses for fair value changes on energy derivative instruments that do not qualify for hedge accounting are recorded in revenues or energy purchases and fuel as appropriate.

In November 2011, the Company disposed of its interest in CPILP as discussed under Significant Events. Accordingly, at December 31, 2011, the Company did not have any forward foreign currency contracts outstanding since these contracts were primarily used to economically hedge U.S. dollar denominated revenues and expected future net U.S. dollar cash flows from CPILP's U.S. plants. At December 31, 2010, the fair value of the Company's forward foreign currency contracts was a net derivative asset of $33 million. Unrealized and realized losses on foreign exchange derivatives that are not designated as hedges for accounting purposes are recorded in energy revenues or foreign exchange gains and losses.

At December 31, 2011, the fair value of the Company's forward bond sale contracts was a net derivative instrument liability of $8 million. These contracts were entered into in August 2011 and will mature in March 2012. The unrealized changes in the fair value of these contracts for the fourth quarter of 2011 were recognized in financing expenses, as discussed under Consolidated Other Expenses and Non-controlling Interests. At December 31, 2010, the fair value of the Company's two $100 million forward bond sale contracts was a derivative instrument liability of $6 million.

Other comprehensive income

For the years ended December 31, 2011 and December 31, 2010, losses net of income taxes on derivative instruments designated as cash flow hedges of $100 million and $38 million, respectively, were recorded in other comprehensive income for the effective portion of cash flow hedges. Realized losses, net of income taxes, for the year ended December 31, 2011 of $45 million and for the year ended December 31, 2010 of $8 million were reclassified to energy purchases and revenues as appropriate. For the years ended December 31, 2011 and December 31, 2010, the change in the fair value of the ineffective portion of hedging derivatives recognized in the statement of income, before non-controlling interests, was a loss of $2 million and a gain of $2 million, respectively.

Disclosure Controls and Procedures and Internal Control over Financial Reporting

As at December 31, 2011, management conducted an evaluation of the design and operation 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. 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.

As at December 31, 2011, management conducted an evaluation of the design and operation 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 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 2011 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting. The Company's transition to IFRS did not result in any significant changes to the Company's internal controls.

Summary of Quarterly Results

(GWh)	Three months ended							
Electricity generation	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**	**Sep 30 2010**	**Jun 30 2010**	**Mar 31 2010**
Total generation excluding acquired Sundance PPA and CPILP plants	3,780	4,221	3,207	2,451	2,556	2,329	2,059	2,261
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	222	496	477	482	272	475	432	483
Keephills 3	485	336	50	-	-	-	-	-
Joffre	104	90	57	98	82	67	93	41
Clover Bar Energy Centre 1, 2 and 3	132	57	40	162	179	37	102	43
Taylor Coulee Chute	2	12	2	-	1	7	3	-
Clover Bar Landfill Gas	7	9	9	8	9	9	10	10
Alberta commercial plants – owned	952	1,000	635	750	543	595	640	577
Acquired Sundance PPA	596	545	701	758	749	680	728	751
	1,548	1,545	1,336	1,508	1,292	1,275	1,368	1,328
Alberta contracted plants								
Genesee 1	855	843	661	768	854	841	780	813
Genesee 2	849	845	789	831	826	824	571	825
	1,704	1,688	1,450	1,599	1,680	1,665	1,351	1,638
Ontario and British Columbia contracted plants								
Kingsbridge 1	35	12	24	31	39	18	22	26
Miller Creek	8	49	26	5	7	46	35	7
Brown Lake	14	8	15	14	14	5	11	13
Island Generation	1	-	55	52	273	n/a	n/a	n/a
	58	69	120	102	333	69	68	46
North East U.S. commercial plants								
Bridgeport	499	872	645	n/a	n/a	n/a	n/a	n/a
Rumford	83	170	68	n/a	n/a	n/a	n/a	n/a
Tiverton	389	422	289	n/a	n/a	n/a	n/a	n/a
	971	1,464	1,002	n/a	n/a	n/a	n/a	n/a
North Carolina U.S. contracted plants								
Roxboro	36	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Southport	59	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	95	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CPILP plants	427	1,294	1,155	1,139	1,311	1,306	1,128	1,268

(%)	Three months ended							
Plant availability	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**	**Sep 30 2010**	**Jun 30 2010**	**Mar 31 2010**
Total average plant availability excluding acquired Sundance PPA and CPILP plants	87%	97%	91%	93%	91%	93%	83%	93%
Alberta commercial plants and acquired Sundance PPA								
Genesee 3	44%	100%	100%	100%	56%	99%	96%	100%
Keephills 3	99%	100%	n/a	n/a	n/a	n/a	n/a	n/a
Joffre	93%	99%	78%	99%	99%	98%	84%	100%
Clover Bar Energy Centre 1, 2 and 3	99%	91%	65%	54%	95%	63%	52%	72%
Taylor Coulee Chute	100%	100%	94%	100%	100%	100%	90%	98%
Clover Bar Landfill Gas	77%	86%	86%	95%	88%	92%	96%	96%
Alberta commercial plants – owned	84%	97%	82%	87%	83%	86%	76%	90%
Acquired Sundance PPA	81%	72%	91%	98%	95%	88%	93%	97%
	83%	89%	84%	91%	87%	87%	83%	92%
Alberta contracted plants								
Genesee 1	100%	100%	81%	92%	100%	100%	100%	99%
Genesee 2	100%	100%	99%	100%	97%	97%	75%	99%
	100%	100%	90%	96%	98%	99%	87%	99%
Ontario and British Columbia contracted plants								
Kingsbridge 1	98%	99%	99%	98%	100%	99%	100%	99%
Miller Creek	78%	92%	99%	78%	12%	96%	96%	37%
Brown Lake	93%	53%	99%	100%	99%	93%	99%	97%
Island Generation	100%	100%	100%	99%	99%	n/a	n/a	n/a
	98%	98%	100%	97%	91%	97%	98%	74%
North East U.S. commercial plants								
Bridgeport	59%	96%	100%	n/a	n/a	n/a	n/a	n/a
Rumford	94%	95%	99%	n/a	n/a	n/a	n/a	n/a
Tiverton	89%	97%	100%	n/a	n/a	n/a	n/a	n/a
	76%	96%	99%	n/a	n/a	n/a	n/a	n/a
North Carolina U.S. contracted plants								
Roxboro	100%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Southport	100%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	100%	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CPILP plants	96%	96%	88%	92%	95%	97%	90%	95%

Financial results

(unaudited, $millions)	Three months ended							
	Dec 31 2011	Sep 30 2011	Jun 30 2011	Mar 31 2011	Dec 31 2010	Sep 30 2010	Jun 30 2010	Mar 31 2010
Revenues and other income								
Alberta commercial plants, acquired Sundance PPA and portfolio optimization (1)	$ 168	$ 144	$ 215	$ 266	$ 236	$ 247	$ 197	$ 235
Alberta contracted plants	86	87	64	77	75	73	57	73
Ontario and British Columbia contracted plants	13	12	13	13	12	3	3	3
North East U.S. commercial plants and portfolio optimization	51	71	51	-	-	-	-	-
North Carolina U.S. contracted plants	14	-	-	-	-	-	-	-
CPILP plants	51	139	129	128	140	130	116	139
Other portfolio activities	21	19	18	34	21	20	22	43
Corporate	5	5	6	6	6	5	10	6
Interplant category transaction eliminations	(11)	(16)	(17)	(20)	(16)	(14)	(18)	(15)
	398	461	479	504	474	464	387	484
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments, and natural gas held for trading	-	(5)	(8)	(49)	(50)	38	(55)	12
Unrealized changes in fair value of CPILP's foreign exchange contracts	9	(23)	1	3	11	11	(19)	5
	9	(28)	(7)	(46)	(39)	49	(74)	17
	$ 407	**$ 433**	**$ 472**	**$ 458**	**$ 435**	**$ 513**	**$ 313**	**$ 501**
EBITDA								
Alberta commercial plants and portfolio optimization	$ 70	$ 72	$ 44	$ 38	$ 43	$ 59	$ 46	$ 53
Alberta contracted plants	51	57	35	47	40	47	29	44
Ontario and British Columbia contracted plants	10	8	10	10	7	2	2	2
North East U.S. commercial plants and portfolio optimization)	6	10	10	-	-	-	-	-
North Carolina U.S. contracted plant	4	-	-	-	-	-	-	-
CPILP plants	19	48	37	44	36	45	43	50
Other portfolio activities	6	-	2	-	(6)	5	(5)	6
Corporate	(26)	(28)	(28)	(23)	(29)	(29)	(25)	(20)
Interplant category transaction eliminations	-	-	-	-	(1)	-	-	-
	140	167	110	116	90	129	90	135
Unrealized changes in fair value of CPLP's energy and foreign exchange derivative instruments and natural gas held for trading	-	(5)	-	(34)	(12)	14	(37)	9
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	10	(23)	2	2	13	7	(18)	(2)
	10	(28)	2	(32)	1	21	(55)	7
	$ 150	**$ 139**	**$ 112**	**$ 84**	**$ 91**	**$ 150**	**$ 35**	**$ 142**

Quarterly revenues, net income and funds provided by operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, and planned and unplanned plant outages as well as items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's derivative power, 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 2011	Sep 30 2011	Jun 30 2011	Mar 31 2011	Dec 31 2010	Sep 30 2010	Jun 30 2010	Mar 31 2010
Revenues and other income	$ 407	$ 433	$ 472	$ 458	$ 435	$ 513	$ 313	$ 501
EBITDA [(1)]	150	139	112	84	91	150	35	142
Net income (loss)	152	44	(22)	14	22	(3)	(34)	92
Net income (loss) attributable to shareholders of the Company	84	15	(25)	3	(3)	16	(8)	12
Earnings (loss) per share	$ 1.47	$ 0.29	$ (0.67)	$ 0.06	$ (0.13)	$ 0.74	$ (0.37)	$ 0.55
Normalized earnings per share [(1)]	$ 0.36	$ 0.43	$ 0.07	$ 0.33	$ 0.21	$ 0.64	$ 0.05	$ 0.51

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

	Three months ended							
Spot price averages	**Dec 31 2011**	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**	**Sep 30 2010**	**Jun 30 2010**	**Mar 31 2010**
Alberta power ($/MWh)	$ 76	$ 95	$ 52	$ 82	$ 46	$ 36	$ 81	$ 41
New England mass hub (US$/MWh)	$ 38	$ 47	$ 42	n/a	n/a	n/a	n/a	n/a
Alberta natural gas (AECO) ($/Gj)	$ 3.03	$ 3.47	$ 3.68	$ 3.57	$ 3.79	$ 3.36	$ 3.70	$ 4.72
Capital Power's Alberta portfolio's average realized power price ($/MWh)	$ 75	$ 74	$ 56	$ 64	$ 64	$ 66	$ 66	$ 67

Factors impacting the 2011 fourth quarter results

During the quarter ended December 31, 2011, the Company recorded net income attributable to shareholders of $84 million and normalized earnings per share of $0.36 which were significant increases compared with the results of the previous quarters in 2011 and 2010. This increase was primarily due to the pre-tax gain of $89 million on the disposal of CPILP in the fourth quarter. This gain was excluded from normalized earnings per share.

The events and items that affected the Company's results for this quarter included the disposal of CPILP in November 2011, the inclusion of a full quarter's results for Keephills 3 after its commissioning in September 2011, and the combined effects of plant outages and higher power prices in the Alberta market.

Capital Power's Genesee 3 plant experienced an unplanned outage which reduced its generation volumes but this was partly offset by increased generation from the Company's CBEC facility. This and other Alberta portfolio optimization activities given the higher power prices experienced due to plant outages and higher demand helped offset a portion of the loss of earnings from Genesee 3 being offline.

For the three months ended December 31, 2011, Alberta commercial plants and acquired Sundance PPA production increased relative to the first two quarters of 2011 and decreased compared with generation volume for the third quarter of 2011. These changes in production levels reflected the addition of Keephills 3 in September 2011 and increased opportunities to dispatch the Company's Alberta based peaking and mid-merit plants (CBEC and Joffre) and fourth quarter plant outages for Genesee 3 and Sundance Unit 6. These factors, particularly the Genesee 3 outage, also influenced the changes in availability on a quarter-over-quarter basis. Genesee 3 went offline on November 11, 2011 and returned to service on January 15, 2012. Sundance Unit 6 went offline on August 18, 2011 due to a transformer failure and remained offline until October 14, 2011 for planned maintenance.

In the fourth quarter of 2011, Alberta spot prices averaged $76/MWh and consistent with most other quarters of 2011 were higher than the same quarters of the previous year. The higher prices for the fourth quarter of 2011 were primarily the result of several significant coal plant outages in the area including the Company's Genesee 3 and acquired Sundance PPA units. Increased demand and market participant offer strategies at the onset of the quarter led to higher Alberta power prices but were partly offset by increased wind volumes, warm weather and conservative market participant pricing as the quarter came to an end. The realized price for the Company's Alberta commercial portfolio was $75/MWh for the fourth quarter of 2011 compared with the spot price average of $76/MWh.

Generally lower revenues in the three months ended December 31, 2011 compared with previous quarters primarily reflected the Company's loss of its RRT contracts with EPCOR and the impact of high Alberta power prices on the settlement of the Company's derivative sell contracts at contracted strike prices lower than the prevailing Alberta power prices. Lower revenues were partly offset by the addition of Keephills 3 in September 2011 and increased opportunities to dispatch CBEC and Joffre.

Lower revenues related to the termination of the Company's contracts with EPCOR were almost completely offset by lower costs from the termination of these contracts making the EBITDA impact immaterial. The favorable EBITDA in the fourth quarter of 2011 compared with previous quarters was primarily driven by the impact of high Alberta power prices on the Company's portfolio position, particularly in the first week of October 2011, when Alberta power prices averaged $203/MWh. A significant amount of portfolio length was lost with the unplanned outages for Genesee 3 and Sundance Units 5. Portfolio optimization strategies utilized by the Company mitigated what could have otherwise been significant losses and allowed the Company to take advantage of high Alberta power prices. The maintenance costs, net of insurance recoveries, for the Genesee 3 outage were approximately $2 million. The Company was able to partly offset the unfavourable revenue contribution from losses on derivative sell contracts with lower losses on derivative buy contracts in the three months ended December 31, 2011 compared with the same period of 2010.

Revenues and EBITDA for Alberta contracted plants in the fourth quarter of 2011 continued the trend of higher results in 2011 compared to 2010 primarily due to higher net availability incentive revenues based on higher 2011 rolling average power prices. The favourable revenues and EBITDA changes were partly offset by increased operating expenses including transmission and power charges for higher production and new initiatives to comply with anticipated environmental requirements.

North East U.S plants and portfolio optimization revenues and EBITDA for the fourth quarter of 2011 were negatively impacted by market conditions including relatively low power prices and spark spreads and the level of required plant maintenance work. Due to these factors, the Rumford plant did not operate for most of December 2011.

When the Company sold its limited partnership units of CPILP to Atlantic Power effective November 5, 2011 (see Significant Events), the results for CPILP operations were not consolidated with the Company's results after the effective date. Thus, revenues and EBITDA for the three months ended December 31, 2011 have decreased relative to previous quarters.

Net income attributable to shareholders of the Company for quarter ended December 31, 2011 included a $5 million valuation adjustment of pension obligations that decreased pension expense. This pension valuation adjustment was based on an actuarial valuation of the Company's pension plans. It was partly offset by higher short-term incentive payments for the three months ended December 31, 2011.

Factors impacting results for the previous quarters

Significant events and items which affected results for the previous quarters were as follows:

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

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

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

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

In the third quarter of 2010, the expected recovery of $8 million in business insurance proceeds relating to the outage of CBEC Unit 2 from March 8 until September 22, 2010 was recorded in the results for Alberta commercial plants and portfolio optimization. CPILP's results included impairment losses of $66 million reflecting lower expectations for the availability of waste heat fuel supply at CPILP's Ontario plants. Corporate results included $7 million for the recognition of the obligation to EPCOR for operations and maintenance costs for the Rossdale plant over the ten-year period ending in 2019. Income taxes reflected the recognition of a deferred income tax liability relating to the investment in CPILP, as a result of the strategic alternatives review.

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

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

Share and Partnership Unit Information

Quarterly common share trading information

The Company's common shares trade on the Toronto Stock Exchange under the symbol CPX and began trading on June 26, 2009.

	Three months ended							
	Dec 31 2011	**Sep 30 2011**	**Jun 30 2011**	**Mar 31 2011**	**Dec 31 2010**	**Sep 30 2010**	**Jun 30 2010**	**Mar 31 2010**
Share price ($/ common share)								
High	$ 25.78	$ 26.38	$ 28.00	$ 26.44	$ 24.84	$ 24.20	$ 23.39	$ 23.00
Low	$ 22.88	$ 21.50	$ 24.90	$ 22.80	$ 23.25	$ 21.75	$ 21.76	$ 20.97
Close	$ 25.12	$ 25.45	$ 25.00	$ 25.92	$ 23.65	$ 24.10	$ 22.14	$ 22.50
Volume of shares traded (millions)	10.6	7.6	9.5	8.9	3.4	2.4	4.4	7.6

Outstanding share and partnership unit data

As at March 13, 2012, the Company had 58.969 million common shares outstanding, 38.216 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 44.254 million for the year ended December 31, 2011. All of the outstanding special voting shares and the outstanding special limited voting share are held by EPCOR.

As at March 13, 2012, CPLP had 21.750 million general partnership units outstanding, 36.924 million common limited partnership units outstanding and 38.216 million exchangeable common limited partnership units outstanding, which are exchangeable for 38.216 million common shares of the Company. All of the outstanding general partnership units and the outstanding common limited partnership units are held, indirectly, by the Company. All of the outstanding exchangeable common limited partnership units are held by EPCOR.

Additional Information

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

Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(In millions of Canadian dollars)
Years ended December 31, 2011 and 2010

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 International Financial Reporting Standards. 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 13, 2012. 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 International Financial Reporting Standards. 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 fulfills 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 13, 2012

CAPITAL POWER CORPORATION
Consolidated Financial Statements

Years ended December 31, 2011 and 2010

KPMG LLP
Chartered Accountants
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Edmonton AB T5J 3V8
Canada

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Capital Power Corporation

We have audited the accompanying consolidated financial statements of Capital Power Corporation, which comprise the consolidated statements of financial position as at December 31, 2011 and 2010 and January 1, 2010, the consolidated statements of income, comprehensive income, changes in equity and cash flows for the years ended December 31, 2011 and 2010, 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 International Financial Reporting Standards, 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 opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Capital Power Corporation as at as at December 31, 2011 and 2010 and January 1, 2010, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2011 and 2010 in accordance with International Financial Reporting Standards**.**

KPMG LLP

Chartered Accountants

March 13, 2012
Edmonton, Canada

CAPITAL POWER CORPORATION

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

Years ended December 31, 2011 and 2010

	2011	2010
Revenues	$1,691	$ 1,707
Other income	79	55
Energy purchases and fuel	(904)	(990)
Gross income	866	772
Other raw materials and operating charges (note 4)	(149)	(104)
Staff costs and employee benefits expense (note 4)	(155)	(175)
Depreciation and amortization (note 4)	(229)	(241)
Impairments (note 8)	(43)	(65)
Other administrative expenses (note 4)	(56)	(57)
Property taxes	(21)	(18)
Foreign exchange losses	(13)	(1)
Operating income	200	111
Gains on acquisitions and disposals (notes 8 and 9)	93	30
Finance expense (note 5)	(105)	(78)
Income before tax	188	63
Income tax recovery (note 6)	-	14
Net income	$ 188	$ 77
Attributable to:		
Non-controlling interests	$ 111	$ 60
Shareholders of the Company	$ 77	$ 17

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

	2011	2010
Basic (note 7)	$ 1.60	$ 0.77
Diluted (note 7)	$ 1.59	$ 0.69

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Comprehensive Income
(In millions of Canadian dollars)

Years ended December 31, 2011 and 2010

	2011	2010
Net income	$ 188	$ 77
Other comprehensive income (loss):		
Available-for-sale assets:		
Unrealized (losses) gains on available-for-sale financial assets[1]	(1)	9
Cash flow hedges:		
Unrealized losses on derivative instruments[2]	(100)	(38)
Reclassification of losses on derivative instruments to income for the year[3]	45	8
Reclassification of ineffective portion to income for the year[4]	2	(2)
Defined benefit plans:		
Actuarial losses[5]	(5)	(2)
Net investment in foreign subsidiaries:		
Unrealized gain (loss)[6]	39	(32)
Losses realized in net income on disposal of CPILP (note 8) [7]	21	-
Other comprehensive income (loss), net of tax	1	(57)
Total comprehensive income	$ 189	$ 20
Attributable to:		
Non-controlling interests	$ 110	$ 11
Shareholders of the Company	$ 79	$ 9

[1] For the year ended December 31, 2011, net of income tax recovery of $1. For the year ended December 31, 2010, net of income tax expense of $4.

[2] For the year ended December 31, 2011, net of income tax recovery of $18. For the year ended December 31, 2010, net of income tax recovery of $19.

[3] For the year ended December 31, 2011, net of reclassification of income tax recovery of $8. For the year ended December 31, 2010, net of reclassification of income tax recovery of $1.

[4] For the years ended December 31, 2011 and December 31, 2010, net of income tax expense of nil.

[5] For the year ended December 31, 2011, net of income tax recovery of $2. For the year ended December 31, 2010, net of income tax recovery of $1.

[6] For the year ended December 31, 2011, net of income tax expense of nil. For the year ended December 31, 2010, net of income tax expense of $2.

[7] For the year ended December 31, 2011, net of reclassification of income tax recovery of $10. For the year ended December 31, 2010, net of income tax expense of nil.

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Financial Position
(In millions of Canadian dollars)

	December 31, 2011	December 31, 2010 (note 37)	January 1, 2010 (note 37)
Assets			
Current assets:			
Cash and cash equivalents (note 10)	$ 73	$ 56	$ 52
Trade and other receivables (note 11)	198	286	315
Inventories (note 12)	59	60	68
Derivative financial instruments assets (note 13)	25	152	146
Other financial assets (note 15)	53	-	-
Assets classified as held for sale (note 8)	-	-	36
	408	554	617
Non-current assets:			
Other assets	24	19	20
Derivative financial instruments assets (note 13)	13	76	155
Finance lease receivables (note 14)	58	85	91
Other financial assets (note 15)	42	89	70
Deferred tax assets (note 16)	14	40	33
Intangible assets (note 17)	296	651	702
Property, plant and equipment (note 18)	3,842	3,678	3,345
Goodwill (note 19)	46	104	128
Total assets	$ 4,743	$ 5,296	$ 5,161

Approved on behalf of the Board:

Donald Lowry
Director and Chairman of the Board

William Bennett
Director and Chairman of the Audit Committee

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Financial Position
(In millions of Canadian dollars)

	December 31, 2011	December 31, 2010 (note 37)	January 1, 2010 (note 37)
Liabilities and equity			
Current liabilities:			
Trade and other payables (note 20)	$ 220	$ 282	$ 325
Derivative financial instruments liabilities (note 13)	67	125	107
Loans and borrowings (note 21)	28	235	247
Deferred revenue and other liabilities	13	10	8
Provisions (note 22)	33	20	8
	361	672	695
Non-current liabilities:			
Derivative financial instruments liabilities (note 13)	7	89	95
Loans and borrowings (note 21)	1,452	1,634	1,472
Deferred revenue and other liabilities	76	61	55
Deferred tax liabilities (note 16)	55	73	92
Provisions (note 22)	197	155	136
	1,787	2,012	1,850
Equity:			
Equity attributable to shareholders of the Company			
Share capital (note 24)	1,499	820	477
Retained earnings	16	8	7
Other reserves (note 25)	8	5	9
Retained earnings and other reserves	24	13	16
	1,523	833	493
Non-controlling interests	1,072	1,779	2,123
Total equity	2,595	2,612	2,616
Commitments and contingencies (note 33)			
Subsequent events (note 36)			
Total liabilities and equity	$ 4,743	$ 5,296	$ 5,161

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Equity
(In millions of Canadian dollars)

	Share capital (note 24)	Cash flow hedges[1]	Cumulative translation account[1]	Available-for-sale financial assets[1]	Defined benefit plan actuarial gains (losses)[1]	Employee benefits reserve	Retained earnings	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2011	$ 820	$ 7	$ (7)	$ 1	$ (2)	$ 6	$ 8	$ 833	$ 1,779	$ 2,612
Net income	-	-	-	-	-	-	77	77	111	188
Other comprehensive income (loss):										
Net change in fair value of available-for-sale financial assets	-	-	-	(2)	-	-	-	(2)	-	(2)
Cash flow derivative hedge losses	-	(118)	-	-	-	-	-	(118)	-	(118)
Reclassification of losses to income	-	53	-	-	-	-	-	53	-	53
Reclassification of ineffective portion to income	-	2	-	-	-	-	-	2	-	2
Defined benefit plan actuarial losses	-	-	-	-	(7)	-	-	(7)	-	(7)
Unrealized gain on foreign currency translation	-	-	39	-	-	-	-	39	-	39
Losses realized in net income on disposal of CPILP(note 8)	-	23	11	(3)	-	-	-	31	-	31
Tax on items recognized directly in equity	-	(1)	-	2	2	-	-	3	-	3
Attributed to non-controlling interests	-	25	(26)	2	-	-	-	1	(1)	-
Other comprehensive income (loss)	-	(16)	24	(1)	(5)	-	-	2	(1)	1
Total comprehensive income (loss)	-	(16)	24	(1)	(5)	-	77	79	110	189
Issue of share capital	694	-	-	-	-	(1)	3	696	(242)	454
Transaction costs	(20)	-	-	-	-	-	-	(20)	-	(20)
Deferred taxes	5	(1)	-	-	-	-	-	4	-	4
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	(115)	(115)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	-	11	11
Reduction in non-controlling interests on disposal of CPILP (note 8)	-	-	-	-	-	-	(6)	(6)	(474)	(480)
Issue of partnership units	-	-	-	-	-	-	-	-	14	14
Common share dividends (note 24)	-	-	-	-	-	-	(60)	(60)	-	(60)
Preferred share dividends (note 24)	-	-	-	-	-	-	(6)	(6)	-	(6)
Preferred share dividends paid by subsidiary	-	-	-	-	-	-	-	-	(11)	(11)
Share-based compensation	-	-	-	-	-	3	-	3	-	3
Equity as at December 31, 2011	$ 1,499	$ (10)	$ 17	$ -	$ (7)	$ 8	$ 16	$ 1,523	$ 1,072	$ 2,595

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

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Equity
(In millions of Canadian dollars)

	Share capital (note 24)	Cash flow hedges[1]	Cumulative translation account[1]	Available-for-sale financial assets[1]	Defined benefit plan actuarial gains (losses)[1]	Employee benefits reserve	Retained earnings	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2010	$ 477	$ 7	$ -	$ -	$ -	$ 2	$ 7	$ 493	$ 2,123	$ 2,616
Net income	-	-	-	-	-	-	17	17	60	77
Other comprehensive income (loss):										
Net change in fair value of available-for-sale financial assets	-	-	-	13	-	-	-	13	-	13
Cash flow derivative hedge losses	-	(57)	-	-	-	-	-	(57)	-	(57)
Reclassification of losses to income	-	9	-	-	-	-	-	9	-	9
Reclassification of ineffective portion to income	-	(2)	-	-	-	-	-	(2)	-	(2)
Unrealized loss on foreign currency translation	-	-	(30)	-	-	-	-	(30)	-	(30)
Defined benefit plan actuarial losses	-	-	-	-	(3)	-	-	(3)	-	(3)
Tax on items recognized directly in equity	-	18	(2)	(4)	1	-	-	13	-	13
Attributed to non-controlling interests	-	32	25	(8)	-	-	-	49	(49)	-
Other comprehensive income (loss)	$ -	$ -	$ (7)	$ 1	$ (2)	$ -	$ -	$ (8)	$ (49)	$ (57)
Total comprehensive income (loss)	-	-	(7)	1	(2)	-	17	9	11	20
Issue of preferred shares	122	-	-	-	-	-	-	122	-	122
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	(137)	(137)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	-	12	12
Issue of partnership units	-	-	-	-	-	-	-	-	27	27
Common share dividends (note 24)	-	-	-	-	-	-	(30)	(30)	-	(30)
Preferred share dividends paid by subsidiary	-	-	-	-	-	-	-	-	(14)	(14)
Share-based compensation	-	-	-	-	-	4	-	4	-	4
Exchange of CPLP units for common shares	221	-	-	-	-	-	14	235	(243)	(8)
Equity as at December 31, 2010	$ 820	$ 7	$ (7)	$ 1	$ (2)	$ 6	$ 8	$ 833	$ 1,779	$ 2,612

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

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Cash Flows
(In millions of Canadian dollars)

Years ended December 31, 2011 and 2010

	2011	2010
Cash flows from operating activities:		
Net income	$ 188	$ 77
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	229	241
Gains on acquisitions and disposals	(93)	(30)
Impairments (note 8)	43	65
Finance expense	105	78
Fair value changes on derivative instruments	49	36
Unrealized foreign exchange losses	6	1
Income tax recovery	-	(14)
Other items	(6)	(8)
Interest paid[1]	(88)	(58)
Income taxes paid	(14)	(6)
Income taxes recovered	-	15
	419	397
Change in non-cash operating working capital (note 26)	42	(6)
Net cash flows from operating activities	461	391
Cash flows used in investing activities:		
Business acquisitions, net of acquired cash (note 9)	(647)	(205)
Payments to acquire property, plant and equipment and other assets	(493)	(329)
Proceeds on disposal of assets (note 8)	131	64
Other cash flows from (used in) investing activities	24	(13)
Net cash flows used in investing activities	(985)	(483)
Cash flows from financing activities:		
Proceeds from issue of loans and borrowings	604	425
Repayment of loans and borrowings	(293)	(247)
Debt issue costs	(5)	(5)
Proceeds from issue of common shares (note 24)	469	1
Proceeds from issue of preferred shares (note 24)	-	125
Share issue costs (note 24)	(20)	(4)
Distributions paid to non-controlling interests	(110)	(112)
Common share dividends paid (note 24)	(51)	(27)
Preferred share dividends paid (note 24)	(6)	-
Preferred share dividends paid by subsidiary	(11)	(13)
Interest paid[1]	(36)	(44)
Net cash flows from financing activities	541	99
Foreign exchange losses on cash held in a foreign currency	-	(3)
Net increase in cash and cash equivalents	17	4
Cash and cash equivalents at beginning of year	56	52
Cash and cash equivalents at end of year	$ 73	$ 56

[1] Total interest paid.

See accompanying notes to the consolidated financial statements

1. Reporting entity:

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

The registered and head office of the Company is located at 10423 101 Street, Edmonton, Alberta, Canada, T5H 0E9. The common shares of the Company are traded on the Toronto Stock Exchange under the symbol “CPX”.

2. Significant accounting policies:

(a) Basis of presentation and conversion to IFRS:

These consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS). These are the Company's first annual consolidated financial statements prepared in accordance with IFRS and IFRS 1 First time Adoption of International Financial Reporting Standards has been applied.

An explanation of how the transition to IFRS has affected the financial position, financial performance and cash flows of the Company is provided in note 37. This note includes reconciliations of equity and total comprehensive income reported under previous Canadian generally accepted accounting principles (GAAP) to those reported under IFRS for the opening IFRS statement of financial position as at January 1, 2010 (transitional date) and as at and for the year ended December 31, 2010.

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

These consolidated financial statements were approved and authorized for issue by the Board of Directors on March 13, 2012.

(b) Basis of consolidation:

These consolidated financial statements include the accounts of Capital Power and its subsidiaries. Subsidiaries are fully consolidated from the date of acquisition, being the date on which the Company obtains control, and continue to be consolidated until the date that such control ceases to exist.

The Company has an approximate 60.6% interest in Capital Power L.P. (CPLP) (December 31, 2010 – 39.5%, January 1, 2010 – 27.8%). Based on an assessment of the relationship between Capital Power and CPLP, Capital Power controls CPLP and therefore CPLP is treated as a subsidiary of Capital Power.

EPCOR Utilities Inc. (EPCOR) holds 38.216 million (December 31, 2010 – 47.416 million, January 1, 2010 – 56.625 million) exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) which represents approximately 39.4% of CPLP (December 31, 2010 – 60.5%, January 1, 2010 – 72.2%). 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. 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. Although EPCOR, through its ownership of the special voting shares described above, is the largest single shareholder, its representation on the board of directors does not represent a controlling vote. Since a subsidiary of Capital Power is the general partner of CPLP, Capital Power has control over CPLP and, on that basis, the operations of CPLP are consolidated by Capital Power for financial statement purposes.

As a result of the disposal of Capital Power Income L.P. (CPILP), as described in note 8, the Company has no interest in CPILP as at December 31, 2011 (December 31, 2010 – 29.6%, January 1, 2010 – 30.5%). Prior to the disposal, based on an assessment of the relationship between Capital Power and CPILP, Capital Power controlled CPILP and therefore CPILP was treated as a subsidiary of Capital Power until November 5, 2011, the date of the disposal.

2. Significant accounting policies, continued:

(b) Basis of consolidation, continued:

Prior to the disposal of CPILP, as described in note 8, CPLP held 49% and EPCOR held 51% of the voting rights in CPI Investments Inc. CPI Investments Inc. owned the approximate 29.2% interest (December 31, 2010 – 29.6%, January 1, 2010 – 30.5%) in CPILP. However, as CPLP was entitled to all of the economic interest in CPI Investments Inc., CPLP was the primary beneficiary of CPI Investments Inc. and accordingly, CPLP, and therefore CPC, consolidated the financial results of CPILP until November 5, 2011, the date of the disposal.

Non-controlling interests in subsidiaries are identified separately from the Company's equity. The non-controlling interests may be initially measured either at fair value or at the non-controlling interests' proportionate share of the fair value of the acquired business' identifiable net assets. The choice of measurement basis is made on an acquisition-by-acquisition basis. Subsequent to acquisition, the carrying amount of non-controlling interests is the amount of those interests at initial recognition plus the non-controlling interest's share of subsequent changes in equity. Total comprehensive income is attributed to non-controlling interests even if this results in the non-controlling interests having a deficit balance.

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

The financial statements of the subsidiaries are prepared for the same reporting period as Capital Power, using consistent accounting policies.

(c) Business combinations and goodwill:

Acquisitions on or after January 1, 2010

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of acquisition in exchange for control of the acquired business. Acquisition-related costs are recognized into net income as incurred. Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. When the excess is negative, a bargain purchase gain is recognized immediately into income.

Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the date of acquisition. Where an acquisition involves consideration contingent on future events, any changes in the amount of consideration paid will be recognized into net income.

The Company elects on a transaction-by-transaction basis whether to measure non-controlling interest at its fair value, or at its proportionate share of the recognized amount of the identifiable net assets, at the acquisition date. Transaction costs, other than those associated with the issue of debt or equity securities, that the Company incurs in connection with a business combination are expensed as incurred.

Acquisitions prior to January 1, 2010

On transition to IFRS, the Company has elected not to restate business combinations that occurred prior to the date of transition, January 1, 2010, as described in note 37. Any goodwill arising on such business combinations before the date of transition represents the amount recognized under previous Canadian GAAP.

2. Significant accounting policies, continued:

(c) Business combinations and goodwill, continued:

Goodwill

After initial recognition, goodwill is not amortized, but is measured at cost less any accumulated impairment losses. Goodwill is tested for impairment annually, or more frequently if events or changes in circumstances indicate that the carrying amount may be impaired, at the cash-generating unit (CGU) level. For the purpose of impairment testing, goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the Company's CGUs that are expected to benefit from the acquisition.

For further discussion over impairment of goodwill, refer to the accounting policy for impairment of non-financial assets (note 2(n)).

Where goodwill forms part of a CGU and part of the operation within that unit is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the CGU retained.

(d) Investments in joint ventures:

Capital Power has interests with other parties (the venturers), whereby in each case the venturers have a contractual arrangement that establishes joint control over the economic activities of the arrangement. These arrangements involve the joint ownership of assets which are used to obtain benefits for each venturer, and are considered to be joint asset arrangements.

In these situations Capital Power recognizes its share of the jointly controlled assets and liabilities in accordance with those associated rights and obligations, along with its share of the income from the output of the jointly controlled asset along with its share of any expenses incurred by the joint arrangement. The accounting policies of these joint arrangements are aligned with the accounting policies of the Company.

(e) Foreign currency translation:

Transactions in foreign currencies are translated to the respective functional currencies of the Company, or the subsidiary concerned, at exchange rates in effect at the transaction date. At each reporting date monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect at the date of the statement of financial position. The translation for other non-monetary assets is not updated from historical exchange rates unless they are carried at fair value. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting foreign exchange gains and losses are included in net income.

On consolidation the assets and liabilities of operations that have a functional currency that is different from the Company's functional currency of Canadian dollars, principally on U.S. operations that have a functional currency of U.S. dollars, are translated into Canadian dollars at the exchange rates in effect at the date of the statement of financial position. 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 as part of translation gains and losses.

2. Significant accounting policies, continued:

(f) Revenue recognition:

Energy sales

Revenues from the sales of electricity and natural gas are recognized when the risks and rewards of ownership pass to the buyer, collection is reasonably assured and the price is reasonably determinable. This occurs upon 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.

The Company recognizes revenues from certain of its generation units operating under power purchase agreements (PPAs) as described in note 2(g). PPAs are a form of long-term sales arrangement between the owner of a generation unit and the contracted purchaser under the PPA.

Revenues from other generation units operating under PPAs, which have not been assessed as containing a lease are recognized on delivery of output or upon availability for delivery as prescribed by the respective PPA. In determining the fair value of revenue to be recognized for certain long-term contracts which contain fixed rates which vary dependent on cumulative volume delivered, revenue is recognized as 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.

Revenues from the sale of other goods are recognized when the products have been delivered.

Service revenues

Revenues from operating and management services are recognized when the service has been performed or delivered.

Derivative instruments

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 of short positions occurs and unrealized gains and losses are recorded as revenues based on the related changes in the fair value of the financial instrument at the end of each reporting period.

Deferred revenues

Payments received on one of the Company’s operating leases may be in excess of accounting lease revenues. In such cases, the Company records deferred revenue on its consolidated statement of financial position.

Monetary contributions received from third parties used to either connect a customer to a network or to provide the customer with ongoing access to a supply of goods or services are measured at fair value of the cash received and are initially recorded as deferred revenue. Revenue is recognized as the service is performed, or if an ongoing service is performed as part of an agreement, over the life of the agreement but no longer than the life of the asset.

(g) Leases or arrangements containing a lease:

The Company has entered into PPAs to sell power at predetermined prices. 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. Such types of arrangements may be classified as either finance or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property from the Company are classified as finance leases. PPAs that do not transfer substantially all of the benefits and risks of ownership of property, plant and equipment are classified as either operating leases or executory contracts.

2. Significant accounting policies, continued:

(g) Leases or arrangements containing a lease, continued:

For those PPAs determined to be finance leases with the Company as the lessor, finance income is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is composed of 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 into net income over the lease term.

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

For those PPAs determined to be operating leases with the Company as the lessor, revenue is recognized on a straight-line basis unless another method better represents the earnings process.

Where the Company has purchased goods or services as a lessee, and the lease has been determined to be an operating lease, rental payments are expensed on a straight-line basis over the life of the lease. The Company has not entered into any finance lease arrangements as a lessee.

(h) Non-derivative financial instruments:

Financial assets are identified and classified as either available for sale, held at fair value through income or loss, or loans and receivables. Financial liabilities are classified as either held at fair value through income or loss or other financial liabilities.

Financial instruments at fair value through income or loss

A financial asset is classified as held at fair value through income or loss if it is classified as held for trading or is designated as such upon initial recognition. The Company may designate financial instruments as held at fair value through income or loss 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.

Upon initial recognition transaction costs are recognized into net income as incurred. Financial assets classified as held at fair value through income or loss are measured at fair value with the changes in fair value reported in net income. Fair values are determined in the manner described in note 29.

Gains or losses realized on de-recognition of investments held at fair value through income or loss are recognized into net income.

Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. The Company’s current loans and receivables comprise its cash and cash equivalents and trade and other receivables. Non-current loans and other long-term receivables comprise promissory notes receivable and amounts due from customers more than one year from the date of the statement of financial position which will be repaid between 2012 and 2025.

These assets are recognized initially at fair value plus any directly attributable transaction costs. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses as described in note 2(o). 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.

2. Significant accounting policies, continued:

(h) Non-derivative financial instruments, continued:

Available-for-sale financial assets

The Company's equity investments are classified as available-for-sale financial assets. Available-for-sale financial assets are measured at fair value with any changes in fair value reported in other comprehensive income until the asset is disposed of, or becomes impaired, as described in note 2(o). On derecognition of an available-for-sale financial asset the cumulative gain or loss that was previously recognized in equity is transferred to net income.

Other financial liabilities

The Company's loans and borrowings and trade and other payables are recognized on the date at which the Company becomes a party to the contractual arrangement. Liabilities are derecognized when the contractual obligations are discharged or cancelled or expire.

Liabilities are recognized initially at fair value plus any directly attributable transaction costs, such as debenture discounts, premiums and issue expenses. Subsequently these liabilities are measured at amortized cost using the effective interest rate method.

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.

(i) 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 statement of financial position as derivative financial instruments assets or derivative financial instruments liabilities except for embedded derivative instruments that are clearly and closely related 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. 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.

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 the fair value of the effective portion of the derivatives are recorded in other comprehensive income.

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.

2. Significant accounting policies, continued:

(i) Derivative instruments and hedging activities, continued:

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 derivative instruments are included in the initial carrying amount of the asset acquired in the same period or periods in which the asset is acquired or constructed.

The Company may use non-financial 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 or fuel, as appropriate. The amounts recognized in other comprehensive income as cash flow hedging gains/losses are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income when it becomes probable that the hedged items will not occur.

The Company has not designated any fair value hedges at the date of the statement of financial position.

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.

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 as part of cash flow hedging gains/losses 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.

2. Significant accounting policies, continued:

(i) Derivative instruments and hedging activities, continued:

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized in net income. The fair value of derivative financial 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 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.

(j) Property, plant and equipment:

Property, plant and equipment are recorded at cost, net of accumulated depreciation and/or accumulated impairment losses, if any.

Capitalization

Cost includes contracted services, materials, borrowing costs on qualifying assets, direct labour, directly attributable overhead costs, development costs associated with specific property, plant and equipment and asset retirement costs. When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing a part of an item of property, plant and equipment is capitalized if it is probable that the future economic benefits of the part will flow to the Company and that its cost can be measured reliably. The carrying amount of the replaced part is derecognized. Costs of day to day repairs and maintenance costs are recognized into net income as incurred.

Depreciation

Depreciation is charged to net income on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment, since this most closely reflects the expected pattern of consumption of the asset. Major components of property, plant and equipment are depreciated separately over their respective useful lives. Land and construction work in progress are not depreciated. The estimated useful lives for generation plants and equipment range from 1 to 60 years.

The estimated useful lives, residual values and methods of depreciation are reviewed annually, and adjusted prospectively if appropriate.

Gains and losses on the disposal or retirement of an item of property, plant and equipment are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are recognized into net income within other operating income or other operating costs.

2. Significant accounting policies, continued:

(k) Intangible assets:

Capitalization

Intangible assets with definite lives are recorded at cost, net of accumulated amortization and/or accumulated impairment losses, if any. Intangible assets with definite lives are amortized over the related assets useful lives, as described below. Refer to note 17 for additional discussion over intangible assets.

The only indefinite life intangible assets recorded by the Company are the emission credits.

Amortization

Amortization is charged to net income on a straight-line basis to write-off the cost less the estimated residual value over the estimated remaining term of the agreement or in line with the life of the related generating plant to which it relates. Software work in progress is not amortized as the software is not available for use. Land lease rights will be amortized when the related wind power assets are constructed and commissioned for service over the lives of the related wind power assets or the term of the lease, whichever is shorter. Coal supply access rights are amortized over the life of the coal supply agreement related to the Keephills 3 plant. Emission credits are not amortized, but are expensed as the associated benefits are realized. The periods over which intangible assets are amortized are as follows:

Alberta PPAs	11 years
Contract rights	5 years
Water rights	over the lives of the associated property, plant and equipment
Software	1 to 10 years
Customer rights	30 years

Estimated useful lives, methods of amortization and residual values are reviewed annually, and adjusted prospectively if required.

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount of the asset, and are recognized into net income as other operating income or other operating costs.

(l) Research and development costs:

Expenditures on research activities, undertaken with the prospect of gaining new scientific or technical knowledge and understanding, are recognized in income or loss as incurred.

Development activities involve a plan or design for the production of new or substantially improved products and processes. Development expenditures are capitalized only if development costs can be measured reliably, the product or process is technically and commercially feasible, future economic benefits are probable, and the Company intends to and has sufficient resources to complete development and to use or sell the asset. Other development expenditures are recognized in income or loss as incurred.

Capitalized development expenditures are measured at cost less accumulated amortization and accumulated impairment losses.

(m) Capitalized borrowing costs:

The Company capitalizes interest during construction on its property, plant and equipment and intangible assets to provide for the costs of borrowing on its 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. Qualifying assets are those which necessarily take a significant amount of time to get ready for their intended use.

2. Significant accounting policies, continued:

(n) Impairment of non-financial assets:

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into a CGU, which is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation is subject to an operating segment ceiling test and reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

The Company reviews the recoverability of non-financial assets subject to depreciation or amortization (property, plant and equipment and definite life intangible assets) when events or changes in circumstances may indicate or cause the asset's carrying amount to exceed its recoverable amount. The Company reviews the recoverability of goodwill and indefinite life intangibles on an annual basis, or more frequently if events or changes in circumstances indicate that the carrying amount may be impaired. The asset's recoverable amount is the higher of its fair value less costs to sell and its value in use. The value in use is the present value of expected future cash flows discounted using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. Fair value less costs to sell is based on estimated market values based on actual market transactions, if available. When actual market transactions are not available, a valuation model is used.

The Company's corporate assets do not generate separate cash inflows. If there is an indication that a corporate asset may be impaired, then the recoverable amount is determined for the CGU to which the corporate asset belongs.

Any impairment loss would be recorded in net income in the period when it is determined that the carrying amount of the asset may not be recoverable. The impairment loss would be recorded as the excess of the carrying amount of the asset over its recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs, and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

At the end of each reporting period the Company makes an assessment as to whether there is any indication that previously incurred impairment losses no longer exist. If such an indication exists, the Company estimates the asset's recoverable amount. Any reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount or the carrying amount that would have been determined, after depreciation or amortization, had the original impairment loss not been recognized.

Any reversal is recognized into net income for the period. An impairment loss in respect of goodwill is not reversed.

(o) Impairment of financial assets:

Financial assets, other than those classified as held at fair value through income or loss with changes in fair value recognized in the statement of income, are assessed for indicators of impairment at the end of each reporting period. An impairment loss would be recorded for investments recorded at cost where it is identified that there is objective evidence that one or more events has occurred after the initial recognition of the asset, that has had an impact on the estimated future cash flows of the asset that can be reliably estimated.

For listed and unlisted equity investments classified as available for sale, a significant or prolonged decline in the fair value of the investment below its cost is considered to be objective evidence of impairment.

2. Significant accounting policies, continued:

(o) Impairment of financial assets, continued:

For certain categories of financial assets, such as trade receivables, assets that are assessed not to be impaired individually are in addition assessed for impairment on a collective basis. Objective evidence of impairment includes the Company's past experience of collecting payments, as well as observable changes in national or local economic conditions.

For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the asset's original effective interest rate. Any impairment loss is recognized in net income. If, in a subsequent reporting period, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognized, the previously recognized impairment loss is adjusted through net income.

When an available-for-sale financial asset is considered to be impaired, any cumulative gains or losses previously recognized in other comprehensive income are reclassified to income or loss in the period. Impairment losses previously recognized in income are not reversed through income or loss. Any increase in fair value subsequent to an impairment loss is recognized in other comprehensive income.

(p) Income taxes:

Income tax expense is comprised of current and deferred taxes. Current and deferred tax is recognized in net income except to the extent that it relates to a business combination, or items recognized directly in equity or in other comprehensive income.

Current income taxes for the current period, including any adjustments to tax payable in respect of previous years, are recognized and measured at the amount expected to be recovered from or payable to the taxation authorities based on the tax rates that are enacted or substantively enacted by the end of the reporting period.

Deferred income tax assets and liabilities are recognized for temporary differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases using the tax rates that are expected to apply in the period in which the deferred tax asset or liability is expected to settle, based on the laws that have been enacted or substantively enacted by the reporting date. Such deferred tax assets and liabilities are not recognized if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable income nor the accounting income. Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which they can be utilized. Deferred tax assets are reviewed at each reporting date and reduced accordingly to the extent that it is no longer probable that they can be utilized.

Deferred tax liabilities are recognized for taxable temporary differences associated with investments in subsidiaries, and interests in joint arrangements, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests are only recognized to the extent that it is probable that there will be sufficient taxable income against which to utilize the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

With respect to CPLP, the Company records deferred income tax provisions related to its economic interest in CPLP and the Company records current income taxes pursuant to the provision in the CPLP Limited Partnership Agreement.

2. Significant accounting policies, continued:

(q) Inventories:

Parts and other consumables and coal, principally all 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 circumstance.

(r) 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 measured at amortized cost using the effective interest method.

(s) Government assistance:

Government assistance is recognized when there is reasonable assurance that the Company will comply with the conditions attached to the government assistance and the grants will be received. Such assistance is recorded as a reduction to the related expense or asset.

(t) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. The obligation is discounted using a discount rate that reflects current market assessments of the time value of money and the risks specific to the obligation for which the estimates of future cash flows have not been adjusted. The change in discount rate due to the passage of time is recognized as a finance expense, and is recorded over the estimated time period until settlement of the obligation. Provisions are reviewed and adjusted, when required, to reflect the current best estimate at the end of each reporting period.

The Company recognizes decommissioning provisions in the period in which a legal or constructive obligation is incurred. A corresponding decommissioning cost is added to the carrying amount of the associated property, plant and equipment, and it is depreciated over the estimated useful life of the asset. Accretion of the liability is recorded in finance expense.

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under contract. The provision is measured at the present value of the lower of expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on the assets associated with that contract.

(u) 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 multi-employer 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. It is accounted for as a defined contribution plan as insufficient information exists to enable the Company to account for the plan as a defined benefit plan. Accordingly the Company does not recognize its share of any plan surplus or deficit.

2. Significant accounting policies, continued:

(u) Employee future benefits, continued:

The Company maintains additional defined contribution and defined benefit pension plans to provide pension benefits to those employees (comprising approximately 50% of the 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. 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 date of the statement of financial position 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 period until the benefits become vested, or are recognized immediately into income to the extent that the benefits are already vested. 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. The Company recognizes all actuarial gains and losses immediately in other comprehensive income.

The Company has an unfunded long-term disability 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 discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the date of the statement of financial position 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 immediately in other comprehensive income.

(v) Share-based payments:

The Company operates an equity-settled, share-based compensation plan where each option converts into one common share. The fair value of the employee services received in exchange for the grant of the options is recognized as a compensation expense within staff costs and credited to the employee benefits reserve. The employee benefits reserve is reduced as the options are exercised and the amount initially recorded as a credit in employee benefits reserve is reclassified to share capital. The total amount to be expensed over the vesting period is determined by reference to the fair value of the options granted.

The Company determines the fair value of stock options using a binomial option pricing model at the date of grant. Measurement inputs include the share price on the measurement date, the exercise price of the instrument, expected volatility, expected term of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

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.

2. Significant accounting policies, continued:

(v) Share-based payments, continued:

The fair values of the amounts payable to employees/directors in respect of the Performance Share Unit (PSU) Plan and the Directors' Deferred Share Unit (DSU) Plan, which are settled in cash, are recognized as expenses with corresponding increases in liabilities, over the period that the employees/directors unconditionally become entitled to payments. The liability is re-measured at each reporting date to fair value and at settlement date. Any changes in the fair value of the liability are recognized in income or loss.

(w) 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.

(x) Assets held for sale:

Non-current assets, or disposal groups comprising assets and liabilities, that are expected to be recovered through sale rather than through continuing use, are classified as held for sale. Immediately before classification as held for sale, the assets, or components of the disposal group, are re-measured in accordance with the Company's accounting policies. Thereafter, the assets, or disposal group, are measured at the lower of their carrying amount and fair value less costs to sell. Any impairment losses on initial classification as held for sale or subsequent gain on re-measurement are recognized into net income. Gains are not recognized in excess of any cumulative impairment losses.

(y) Future accounting changes:

A number of new standards, and amendments to standards and interpretations, as described below, are not yet effective for the year ended December 31, 2011 and have not been applied in preparing these consolidated financial statements. The Company is currently assessing the impact of adopting these standards and amendments on its consolidated financial statements. For those standards where earlier application is permitted, the Company expects to apply the changes at the effective date.

IAS 1 – Presentation of Financial Statements – In June 2011, the International Accounting Standards Board (IASB) issued amendments to IAS 1 which will require entities to group items within other comprehensive income on the basis of whether or not they will be reclassified to income or loss in a future period. The implications of adopting the amendments to IAS 1 will be limited to the Company's presentation within its statement of other comprehensive income. The amendments are effective for annual periods beginning on or after July 1, 2012 and are to be applied retrospectively. Earlier application is permitted.

IFRS 7 – Financial Instruments: Disclosures – In December 2011, the IASB issued amendments to IFRS 7 which establishes enhanced disclosure requirements for offsetting financial assets and liabilities. The implications of adopting the amendments to IFRS 7 will result in additional disclosure to the Company's consolidated financial statements. The amendments are effective for annual periods beginning on or after January 1, 2013 and are to be applied retrospectively. Earlier application is permitted.

2. Significant accounting policies, continued:

(y) Future accounting changes, continued:

IFRS 10 – Consolidated Financial Statements – In May 2011, the IASB issued IFRS 10 which replaces IAS 27 – Consolidated and Separate Financial Statements and SIC 12 - Consolidation – Special Purpose Entities. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. The new standard provides a revised definition of control and a single consolidation model as the basis for consolidation for all types of entities. The standard also provides additional guidance to assist in the determination of control. Capital Power does not expect that the adoption of this new standard will have a material effect on the consolidated financial statements, as application of the new definition of control does not change the Company's current accounting treatment for entities in which it holds an interest in. IFRS 10 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 11 and IFRS 12.

IFRS 11 – Joint Arrangements – IFRS 11 was issued in May 2011 and supersedes IAS 31 – Interests in Joint Ventures and SIC 13 – Jointly Controlled Entities – Non-Monetary Contributions by Venturers. The standard classifies joint arrangements as joint operations or joint ventures. Joint operations are arrangements where the owners directly own a share of the individual assets and are directly responsible for contributing a share of the individual liabilities of the joint arrangement. Each owner will account for its share of the arrangement using the proportionate consolidation method. Joint ventures are arrangements where the arrangement itself directly owns the assets and is directly responsible for the liabilities of the arrangement. IFRS 11 eliminated the choice to account for joint ventures using the proportionate consolidation method and instead requires the equity method of accounting. The Company does not expect that the adoption of this new standard will have a material effect on the consolidated financial statements, as it is substantially aligned with the Company's current practice. IFRS 11 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively. Earlier application is permitted but must be applied simultaneously with IFRS 10 and IFRS 12.

IFRS 12 – Disclosures of Interests in Other Entities – In May 2011, the IASB issued IFRS 12, a new and comprehensive standard on disclosure requirements for all forms of interests in other entities, including subsidiaries, joint arrangements, associates and unconsolidated structured entities. IFRS 12 is effective for annual periods beginning on or after January 1, 2013 and is to be applied retrospectively and will result in additional disclosure to the Company's consolidated financial statements. Earlier application is permitted but must be applied simultaneously with IFRS 11 and IFRS 10.

IFRS 13 – Fair value Measurement – In May 2011, the IASB issued IFRS 13 which defines fair value, sets out in a single IFRS a framework for measuring fair value and enhances disclosures about fair value measurements. IFRS 13 applies to fair value measurements required or permitted by other IFRSs, but does not (a) introduce any new requirements to measure an asset or a liability at fair value, (b) change what is measured at fair value in IFRSs, or (c) address how to present changes in fair value. The implications of adopting this new standard will be limited to the Company's fair value disclosures for financial instruments and asset impairment calculations. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and is to be applied prospectively. Earlier application is permitted.

2. Significant accounting policies, continued:

(y) Future accounting changes, continued:

IAS 19 – Employee Benefits – In June 2011, the IASB issued an amendment to IAS 19 which introduced changes related to: (a) eliminating the option to defer the recognition of actuarial gains and losses, known as the corridor method, (b) requiring a new method of calculating finance costs on defined benefit plans where a single discount rate is applied to the net pension assets or obligations, and (c) enhancing the disclosure requirements to provide better information about the characteristics of defined benefit plans and the risks that entities are exposed to through participation in these plans. Capital Power expects that the new method of calculating finance costs will decrease the Company's net income, as the expected return on assets is currently higher than the obligation discount rate. Currently, the extent of the financial impact cannot be estimated. Amendments to IAS 19 are effective for annual periods beginning on or after January 1, 2013 and are to be applied retrospectively. Earlier application is permitted.

International Financial Reporting Standards Interpretations Committee (IFRIC) 20 – Stripping Costs in the Production Phase of a Surface Mine – In October 2011, the IASB issued an interpretation which clarifies the accounting requirement for waste removal costs incurred in the production phase of a surface mine (stripping costs). IFRIC 20 addresses (a) when stripping costs are recognized as an asset, (b) where the costs should be classified on the statement of financial position, and (c) the initial and subsequent measurement of the asset. The Company does not expect that the adoption of this interpretation will have a material effect on the consolidated financial statements, as it is substantially aligned with the Company's current policies. This interpretation is effective for annual periods beginning on or after January 1, 2013 and is to be applied prospectively. Earlier application is permitted.

IAS 32 – Financial Instruments: Presentation – In December 2011, the IASB issued amendments to IAS 32 which clarifies the criteria for offsetting financial assets and liabilities. Capital Power does not expect that the adoption of the amendments will have a material effect on the consolidated financial statements, as they are substantially aligned with the Company's current policies. The amendments are effective for annual periods beginning on or after January 1, 2014 and are to be applied retrospectively. Earlier application is permitted.

IFRS 9 – Financial Instruments – In November 2009, the IASB issued IFRS 9 – Financial Instruments which addresses the classification and measurement requirements of financial assets. The standard was amended in October 2010 to include the requirements for the classification and measurement of financial liabilities. The changes are effective for annual periods beginning on or after January 1, 2015 and are to be applied retrospectively. Earlier application is permitted.

3. Use of judgments and estimates:

The preparation of the Company's consolidated financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses in the consolidated financial statements and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. The Company reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgment in making these estimates and assumptions.

Critical judgments in applying accounting policies

The main judgments that were used in preparing the Company's consolidated financial statements relate to:

Non-financial assets

The determination of CGUs was based on management's judgment, giving consideration to geographic proximity and shared risk exposure and risk management.

Identifying events or changes in circumstances that may indicate or cause an asset's carrying amount to exceed its recoverable amount requires judgment in assessing what events or circumstances would have such an impact.

Classification of arrangements which contain a lease

As noted in note 2(g), the Company has exercised judgment in determining whether the risks and rewards of its generation assets which are subject to a PPA are transferred to the contracted purchaser under the PPA, in determining whether a lease exists and if so, whether the lease should be treated as a finance or operating lease. Details of those PPAs which contain either finance or operating leases are provided in note 14.

Key sources of estimation uncertainty

The main sources of estimation uncertainty in preparing the Company's consolidated financial statements relate to:

Financial instruments

The valuation of the Company's derivative instruments and certain other financial instruments requires estimation of the fair value of each instrument at the reporting date. Details of the basis on which fair values are estimated are provided in notes 13 and 29.

Non-financial assets

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

For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the CGUs that are expected to benefit from the acquisition.

Estimates of fair value for the recoverable amount of CGUs undergoing impairment testing, and for purchase price allocations for business combinations, are primarily based on discounted cash flow projection techniques employing estimated future cash flows based on assumptions regarding the expected market outlook and cash flows from each CGU or asset. The cash flow estimates will vary with the circumstances of the particular assets or CGU and will be based on, among other things, the lives of the assets, contract prices, estimated future prices, revenues and expenses, including growth rates and inflation, and required capital expenditures. Details of the key estimates used in assessing the recoverable amount of each CGU at the last impairment review date are provided in note 19. Market capitalization and comparative market multiples, where available, are used to corroborate management's discounted cash flow projections.

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

3. Use of judgments and estimates, continued:

Key sources of estimation uncertainty, continued

Decommissioning and other provisions

Measurement of the Company's provisions and the related change in discount rate require 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 for the decommissioning provisions and estimates of expected customer renewals for the Company's other provisions. The key assumptions used in determining these provisions are provided in note 22.

Income taxes

Income taxes are determined based on estimates of the Company's current income taxes and estimates of deferred income taxes resulting from temporary tax differences. Deferred income tax assets are assessed to determine the likelihood that they will be realized from future taxable income. Details of tax losses expected to be utilized and the basis of utilization are provided in note 16.

Revenue recognition

As noted in note 2(f), estimates of the value of electricity and natural gas consumed by customers but not billed until subsequent to period-end are based on volume data provided by the parties responsible for delivering the commodity and contracted prices.

Actual results may differ from these estimates. Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

4. Expenses:

	2011	2010
Included in other raw materials and operating charges		
Research and development costs	1	1
Included in staff costs and employee benefits expense		
Equity-settled share-based payments (note 28)	6	6
Post-employment defined contribution plan expense	14	9
Post-employment defined benefit plan (gain) expense (note 23)	(1)	2
Included in depreciation and amortization		
Depreciation of property, plant and equipment (note 18)	192	186
Amortization of intangible assets (note 17)	35	52
Losses on disposal of property, plant and equipment	2	5
Other	-	(2)
	229	241
Included in other administrative expenses		
Operating lease payments	2	2
Research and development costs	-	1

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

5. Finance expense:

	2011	2010
Finance expense:		
Interest on borrowings	$ 114	$ 104
Capitalized interest	(36)	(44)
Total interest expense	78	60
Loss on financial instruments (note 13)	14	6
Unwinding of the discount on decommissioning provisions (note 22)	5	4
Other	8	8
	$ 105	$ 78

6. Income tax:

	2011	2010
Current income tax		
Current income tax	$ 5	$ 10
Deferred income tax		
Amounts previously not recognized on investments in subsidiaries	(5)	5
Relating to origination and reversal of temporary differences	1	(33)
Adjustments in respect of prior periods	1	4
Relating to write-downs of deferred tax asset	(2)	-
Total deferred income tax	(5)	(24)
Income tax expense (recovery)	$ -	$ (14)

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

	2011	2010
Income before tax	$ 188	$ 63
Income tax at the statutory rates of 26.5% and 28.0% respectively	50	18
Increase (decrease) resulting from		
Taxable income attributable to non-controlling interests	(28)	(15)
Non-taxable amounts relating to gains on acquisitions and disposals	(16)	-
Amounts previously not recognized on investments in subsidiaries	(5)	5
Change in valuation allowance	(2)	-
Non-taxable amounts	-	(13)
Prior period tax adjustments	1	4
Change due to enactment of SIFT legislation	-	(11)
Other	-	(2)
Income tax expense (recovery)	$ -	$ (14)

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

7. Earnings per share:

Basic earnings per share

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

	2011	2010
Income for the period attributable to shareholders of the Company	$ 77	$ 17
Preferred share dividends of the Company [1]	(6)	-
Earnings used in the calculation of basic earnings per share	$ 71	$ 17

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

	2011	2010
Weighted average number of common shares used in the calculation of basic earnings per share	44,253,610	22,188,266

Diluted earnings per share

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

	2011	2010
Earnings used in the calculation of basic earnings per share	$ 71	$ 17
Effect of exchangeable limited partnership units issued to EPCOR for common shares [2]	73	37
Earnings used in the calculation of diluted earnings per share	$ 144	$ 54

[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, 2011, 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 $89 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 $16 million. For the year ended December 31, 2010 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 $55 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 $18 million.

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

7. Earnings per share, continued:

Diluted earnings per share

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

	2011	2010
Weighted average number of common shares used in the calculation of basic earnings per share	44,253,610	22,188,266
Effect of dilutive share purchase options[1]	133,446	-
Effect of exchangeable limited partnership units issued to EPCOR for common shares	46,130,521	56,196,088
Weighted average number of common shares used in the calculation of diluted earnings per share	90,517,577	78,384,354

[1] For the year ended December 31, 2011, the average market price of the Company's common shares exceeded the exercise price of certain of the granted share purchase options described in note 28 and as a result had a dilutive effect on earnings per share. For the year ended December 31, 2010, the average market price of the Company's common shares was below the exercise price of all granted share purchase options and as a result none of the share purchase options had a dilutive effect on earnings per share.

8. Disposal of assets:

The gains recognized on disposals of assets were as follows:

	2011	2010
CPILP	$ 89	$ -
Power syndicate agreement	-	28
Other	4	-
Gains on disposals	$ 93	$ 28

CPILP

In November 2011, the Company's indirect subsidiary, CPILP, completed a transaction with a third party, Atlantic Power Corporation (Atlantic), pursuant to which Atlantic acquired directly and indirectly, all of the outstanding limited partnership units of CPILP, including Capital Power's approximate 29.2% ownership interest in CPILP. In connection with and immediately prior to the transaction, Capital Power acquired CPILP's Roxboro and Southport plants in North Carolina (North Carolina Assets) for a $121 million note payable. Atlantic acquired CPILP and its remaining eighteen facilities. Upon close of the transaction, Capital Power received $314 million in combined consideration for its ownership interest in CPILP. The consideration included $48 million of stock in Atlantic, $145 million of cash and the settlement of the $121 million note payable to CPILP for the acquisition of the North Carolina Assets described above. In connection with this transaction, the management contracts between Capital Power and CPILP were terminated or assigned to Atlantic for consideration of $10 million. The Company recognized a total gain on disposal of CPILP, including the termination of the manager contracts, of $89 million, net of legal and other disposal costs of $10 million. Of the $10 million in other disposal costs, $2 million have been recorded as current provisions as at December 31, 2011.

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

8. Disposal of assets, continued:

CPILP, continued

The carrying amounts of the assets and liabilities of CPILP at the time of disposal net of the North Carolina Assets described above were as follows:

	2011
Cash and cash equivalents	$ 23
Trade and other receivables	49
Inventories	14
Derivative financial instruments assets – current and non-current	26
Finance lease receivables	23
Other financial assets – non-current	45
Deferred tax assets	10
Intangible assets	366
Property, plant and equipment	847
Goodwill	83
Trade and other payables	(23)
Derivative financial instruments liabilities – current and non-current	(101)
Loans and borrowings – current and non-current	(724)
Deferred revenue and other liabilities – current and non-current	(14)
Deferred tax liabilities	(7)
Provisions – non-current	(54)
	563
Non-controlling interests in net assets disposed	(474)
Carrying amount of net assets before change in retained earnings	89
Change in retained earnings on change in ownership interest in the North Carolina Assets	(6)
Carrying amount of net assets disposed	$ 83

Immediately before the initial classification of the CPILP assets and management contracts described above to assets held for sale in the second quarter of 2011, the Company determined, based on the negotiated consideration to be received as compared to the existing carrying amounts for the assets to be reclassified to assets held for sale, that it was necessary to test the management contracts for impairments in addition to those recorded upon transition to IFRS and to test certain other cash generating units (CGUs), consisting of various CPILP plants, within the disposal group for potential reversals of impairments recorded upon transition to IFRS. As a result, the Company recorded additional impairments of $43 million on the management contracts immediately prior to reclassification to assets held for sale in the second quarter of 2011, consisting of $7 million within the U.S. geographic area and $36 million within the Canadian geographic area. The Company did not record reversals of any previous impairments taken on its CGUs.

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

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

8. Disposal of assets, continued:

CPILP, continued

Upon close of the transactions described above, accumulated losses of $21 million relating to the Company's investment in CPILP were included in accumulated other comprehensive income, within other reserves within the consolidated statement of financial position. All accumulated other comprehensive losses relating to the Company's investment in CPILP were reclassified to net income, within the gain on disposal, upon close of the disposal transactions.

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 recorded a gain on disposal of $28 million in the first quarter of 2010. The Battle River PSA was previously acquired by the Company, effective July 1, 2009, as a part of the acquisition of assets from EPCOR Utilities Inc. At the acquisition date, the Company recognized fair value adjustments to the Battle River PSA asset for the Company's then 27.8% 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. 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 a third party over a four-year period ending in January 2010.

9. Business combinations:

Acquisitions of Bridgeport, Tiverton and Rumford

On April 28, 2011, a subsidiary of the Company acquired one hundred per cent of the equity interests in Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport Energy), from a third party. Bridgeport Energy is a natural gas-fired combined cycle power generation facility located in Bridgeport, Connecticut, with a nominal capacity of 520 megawatts (MW). The total fair value of consideration was $346 million (US$363 million) in cash, which consists of the acquisition's $338 million (US$355 million) base purchase price, plus normal working capital adjustments of $8 million (US$8 million), and was allocated to the assets acquired and liabilities assumed based on their estimated fair values as described below. Of the total $346 million (US$363 million) consideration, the Company initially paid $349 million (US$367 million) in cash and had an amount receivable of $3 million (US$4 million) from the third party to the transaction. As at December 31, 2011, $1 million (US$1 million) of this amount receivable has been collected.

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

9. Business combinations, continued:

Acquisitions of Bridgeport, Tiverton and Rumford, continued

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

	Bridgeport Energy	Tiverton and Rumford
Trade and other receivables	$ 9	$ 12
Inventories	4	4
Intangible assets	7	3
Deferred tax assets	-	2
Property, plant and equipment	337	289
Goodwill	20	3
Trade and other payables	(13)	(12)
Derivative financial instruments liabilities - current	-	(2)
Derivative financial instruments liabilities - non-current	(8)	-
Deferred tax liabilities	(10)	-
Fair value of net assets acquired	$ 346	$ 299

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

The $9 million and $12 million allocated to trade and other receivables for the Bridgeport Energy and Tiverton and Rumford acquisitions above represent both the estimated fair value and the gross contractual amounts receivable. As at April 28, 2011 and April 29, 2011 for each acquisition respectively, the Company estimated that all of the contractual cash flows pertaining to the acquired trade and other receivables were collectible.

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

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

The results of operations of Bridgeport Energy and Tiverton and Rumford are included in the Company's consolidated statements of income and statements of changes in equity from the dates of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statement of financial position.

Amounts included in the consolidated statement of income for the year ended December 31, 2011, since the respective dates of acquisition are as follows:

	Bridgeport Energy	Tiverton and Rumford
Revenues	$ 102	$ 77
Net income (loss)	(4)	2

Had the acquisitions occurred at January 1, 2011, the Company would have had a total of $1,796 million of revenues and $186 million of net income for the year ended December 31, 2011.

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

9. Business combinations, continued:

Acquisitions of Bridgeport, Tiverton and Rumford, continued

In conjunction with the above acquisitions, the Company incurred $3 million in acquisition costs which have been recorded on the Company's statement of income as other administrative expenses for the year ended December 31, 2011.

Changes in the deferred taxes and working capital adjustments on the Bridgeport Energy acquisition in the fourth quarter of 2011 resulted in changes to the fair values allocated to trade and other receivables and deferred tax liabilities, as compared to the amounts disclosed within the condensed interim consolidated financial statements for the quarter ended September 30, 2011. As of the release date of these financial statements, information required to finalize the working capital adjustments associated with the acquisitions of Bridgeport Energy and Tiverton and Rumford is outstanding and as a result the purchase prices and allocations to the acquired assets and assumed liabilities above are preliminary and are subject to change. The Company expects to finalize the Bridgeport Energy and Tiverton and Rumford purchase price allocations by the second quarter of 2012.

Prior year acquisition of Island Generation Facility

On October 19, 2010, the Company's subsidiary, CPLP, acquired Island Generation, a 275 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 supported 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:

Trade and other receivables	$ 3
Property, plant and equipment	218
Trade and other payables	(3)
Provisions	(2)
Deferred tax liabilities	(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 $3 million allocated to trade and other receivables represents both the estimated fair value and the gross contractual amounts receivable. As at October 19, 2010, the Company estimated that all of the contractual cash flows pertaining to the acquired trade and other receivables were collectible.

The results of operations of Island Generation are included in the Company's consolidated statement of income and statement of changes in equity from the date of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statement of financial position. Since the acquisition date of October 19, 2010, $8 million of revenue and $3 million of net income from Island Generation was 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 Company would have had a total of $1,743 million of revenue and $76 million of net income for the year ended December 31, 2010.

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

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

10. Cash and cash equivalents:

	December 31, 2011	December 31, 2010	January 1, 2010
Cash and cash equivalents	$ 73	$ 56	$ 52

Included in the Company's cash and cash equivalents is its proportionate share of its rights to cash and cash equivalents, which are restricted to use within its joint arrangements of $20 million (December 31, 2010 - $8 million, January 1, 2010 - $17 million).

11. Trade and other receivables:

	December 31, 2011	December 31, 2010	January 1, 2010
Accrued revenues	$ 103	$ 193	$ 179
Trade receivables	64	25	23
Receivables from related parties (note 27)	8	52	63
Government assistance receivable	-	-	9
Finance lease receivable (note 14)	3	4	4
Allowance for doubtful accounts (note 30)	(1)	(1)	(1)
Net trade receivables	177	273	277
Income taxes recoverable	14	6	30
Prepayments	7	7	8
	$ 198	$ 286	$ 315

Details of the aging of trade receivables and analysis of the movement on the allowance for doubtful accounts are provided in note 30.

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

12. Inventories:

	December 31, 2011	December 31, 2010	January 1, 2010
Parts and other consumables	$ 50	$ 47	$ 52
Coal	9	9	8
Natural gas held in storage for trading purposes	-	4	8
	$ 59	$ 60	$ 68

Inventories expensed upon usage for the year ended December 31, 2011 of $39 million (year ended December 31, 2010 - $67 million) were charged to energy purchases and fuel, and other raw materials and operating charges. No write-downs of inventories were recognized in the year ended December 31, 2011 (year ended December 31, 2010 – $1 million). There were no reversals of previous write downs recognized in the year ended December 31, 2011 (year ended December 31, 2010 – nil). At December 31, 2011, no inventories were pledged as security for liabilities (December 31, 2010 – nil, January 1, 2010 - nil).

13. Derivative financial instruments and hedge accounting:

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

The derivative instruments assets and liabilities used for risk management purposes as described in note 30 consist of the following:

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

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

13. Derivative financial instruments and hedge accounting, continued:

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

	January 1, 2010				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative financial instruments assets:					
Current	$ 15	$ 126	$ 5	$ -	$ 146
Non-current	32	97	26	-	155
Derivative financial instruments liabilities:					
Current	(23)	(82)	(2)	-	(107)
Non-current	(37)	(54)	(4)	-	(95)
Net fair value	$ (13)	$ 87	$ 25	$ -	$ 99
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(4)			
Gigajoules of natural gas (millions)	45	13			
Foreign currency (U.S. dollars)			$ (379)		
Bond forwards				$ -	
Range of contract terms in years	0.1 to 7.0	0.1 to 4.8	0.1 to 6.0		

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

13. Derivative financial instruments and hedge accounting, continued:

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

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

	Year ended December 31, 2011		Year ended December 31, 2010	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (62)	$ (53)	$ (46)	$ (9)
Energy non-hedges	(41)	(8)	(38)	21
Foreign exchange non-hedges	(10)	3	8	4
Interest rate non-hedges	(2)	(12)	(6)	-

Realized gains and losses relate only to derivative financial instruments. The following items are included in the Company's statement of income for the years ended December 31, 2011 and 2010.

	2011	2010
Revenues	(142)	(34)
Energy purchases and fuel	39	20
Foreign exchange losses	(6)	-
Finance expense	(14)	(6)

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

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity and natural gas prices. For the year ended December 31, 2011, the changes in the fair value of the ineffective portion of hedging derivatives required to be recognized as losses in the statement of income was $2 million (year ended December 31, 2010 – gains of $2 million).

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

13. Derivative financial instruments and hedge accounting, continued:

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

	December 31, 2011
Within one year	$ (18)
Between one and five years	1
After five years	-
	$ (17)

The Company's cash flow hedges extend to 2016.

14. Leases:

Finance lease receivables

	Minimum lease payments			Present value of minimum lease payments		
	December 31, 2011	December 31, 2010	January 1, 2010	December 31, 2011	December 31, 2010	January 1, 2010
Amounts receivable under finance leases:						
Less than one year	$ 5	$ 9	$ 9	$ 3	$ 4	$ 4
Between one and five years	18	34	35	12	21	20
More than five years	56	78	88	46	64	71
Unearned finance income	(18)	(32)	(37)	-	-	-
Lease payment receivable	61	89	95	61	89	95
Less current portion: (included within trade and other receivables (note 11))	3	4	4	3	4	4
	$ 58	$ 85	$ 91	$ 58	$ 85	$ 91

The PPA under which the Company's power generation facility located in Kingsbridge, Ontario operates, expires in 2026 and has an effective rate inherent in the lease of 3.2%. The lease receivable contains an unguaranteed residual value of $13 million.

Details of the fair value of the finance lease receivables are given in note 29.

Finance income of $4 million was recognized in other income during the year ended December 31, 2011 (year ended December 31, 2010 - $5 million).

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 the Manchief, Mamquam, Moresby Lake, Roxboro, Kenilworth, Greeley, Williams Lake, Genesee units 1 and 2, Miller Creek, Brown Lake and Island Generation are accounted for as assets under operating leases.

As at December 31, 2011 the cost of such property, plant and equipment was $1,250 million (December 31, 2010 - $1,419 million, January 1, 2010 - $1,171 million), less accumulated depreciation of $143 million (December 31, 2010 - $93 million, January 1, 2010 - $32 million).

Manchief, Mamquam, Moresby Lake, Kenilworth, Greeley and Williams Lake were disposed of in November 2011 as described in note 8.

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

14. Leases, continued:

Plants under operating leases, continued

The minimum future rental payments to be received on these PPAs are:

	December 31, 2011
Within one year	$ 66
Between one and five years	269
After five years	326
	$ 661

15. Other financial assets:

	December 31, 2011	December 31, 2010	January 1, 2010
Other financial assets – non-current:			
Available for sale - investments in PERH	$ -	$ 32	$ 19
Available for sale - portfolio investments	3	3	3
Loans and other long-term receivables	38	54	48
Other	1	-	-
	$ 42	$ 89	$ 70
Other financial assets - current:			
Financial assets designated at fair value through income or loss – Atlantic stock (note 8)	$ 53	$ -	$ -

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

16. Deferred tax:

Deferred tax assets and liabilities are attributable to the following:

	Assets			Liabilities			Net		
	December 31, 2011	December 31, 2010	January 1, 2010	December 31, 2011	December 31, 2010	January 1, 2010	December 31, 2011	December 31, 2010	January 1, 2010
Losses carried forward	$ 35	$ 96	$ 79	$ -	$ -	$ -	$ 35	$ 96	$ 79
Difference in accounting and tax basis of property, plant and equipment	5	-	1	(148)	(124)	(113)	(143)	(124)	(112)
Difference in accounting and tax basis of intangible assets	30	22	20	(14)	(45)	(50)	16	(23)	(30)
Deferred partnership income	-	-	-	(6)	(9)	(19)	(6)	(9)	(19)
Derivative instruments	4	21	1	-	(8)	(8)	4	13	(7)
Share issue costs and deferred financing charges	10	9	7	-	-	-	10	9	7
Long-term receivable	-	-	-	-	(7)	-	-	(7)	-
Deferred revenue	12	9	4	-	-	-	12	9	4
Finance lease receivable	-	-	-	(9)	(6)	(5)	(9)	(6)	(5)
Decommissioning provisions	38	24	21	-	-	-	38	24	21
Prepaid reclamation amounts	-	-	-	(10)	(7)	(4)	(10)	(7)	(4)
Other provisions	9	3	2	-	-	-	9	3	2
Long-term investments	-	-	-	-	(14)	(1)	-	(14)	(1)
Other items	3	3	6	-	-	-	3	3	6
Deferred tax assets (liabilities)	146	187	141	(187)	(220)	(200)	(41)	(33)	(59)
Set off of tax	(132)	(147)	(108)	132	147	108	-	-	-
Net deferred tax assets (liabilities)	$ 14	$ 40	$ 33	$ (55)	$ (73)	$ (92)	$ (41)	$ (33)	$ (59)

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

16. Deferred tax, continued:

Movement in temporary differences during the year ended December 31, 2011:

	At January 1, 2011	Recognized in net income	Recognized directly in other comprehensive income	Amounts relating to gains on acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	At December 31, 2011
Losses carried forward	$ 96	$ (4)	$ -	$ (60)	$ 3	$ -	$ 35
Difference in accounting and tax basis of property, plant and equipment	(124)	(52)	-	61	(29)	1	(143)
Difference in accounting and tax basis of intangible assets	(23)	6	-	28	5	-	16
Deferred partnership income	(9)	3	-	-	-	-	(6)
Derivative instruments	13	9	5	(24)	1	-	4
Share issue costs and deferred financing charges	9	(1)	-	(1)	5	(2)	10
Long-term receivable	(7)	-	-	7	-	-	-
Deferred revenue	9	6	-	(5)	2	-	12
Finance lease receivable	(6)	(1)	-	-	(2)	-	(9)
Decommissioning provisions	24	27	-	(17)	4	-	38
Prepaid reclamation amounts	(7)	(1)	-	-	(2)	-	(10)
Other provisions	3	6	-	-	-	-	9
Long-term investments	(14)	7	(1)	8	-	-	-
Other items	3	-	-	-	-	-	3
	$ (33)	$ 5	$ 4	(3)	$ (13)	$ (1)	$ (41)

Movement in temporary differences during the year ended December 31, 2010:

	At January 1, 2010	Recognized in net income	Recognized directly in other comprehensive income	Recognized directly in equity	At December 31, 2010
Losses carried forward	$ 79	$ 13	$ -	$ 4	$ 96
Difference in accounting and tax basis of property, plant and equipment	(112)	5	-	(17)	(124)
Difference in accounting and tax basis of intangible assets	(30)	3	-	4	(23)
Deferred partnership income	(19)	10	-	-	(9)
Derivative instruments	(7)	6	17	(3)	13
Share issue costs and deferred financing charges	7	1	-	1	9
Long-term receivable	-	(7)	-	-	(7)
Deferred revenue	4	5	-	-	9
Finance lease receivable	(5)	(1)	-	-	(6)
Decommissioning provisions	21	1	-	2	24
Prepaid reclamation amounts	(4)	(1)	-	(2)	(7)
Other provisions	2	1	-	-	3
Long-term investments	(1)	(9)	(4)	-	(14)
Other items	6	(3)	(1)	1	3
	$ (59)	$ 24	$ 12	$ (10)	$ (33)

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

16. Deferred tax, continued:

At December 31, 2011 the Company has non-capital losses carried forward of approximately $114 million (December 31, 2010 - $29 million, January 1, 2010 - $20 million), of which $111 million (December 31, 2010 - $12 million, January 1, 2010 - $20 million) relates to certain U.S. subsidiaries. Of the $111 million of non-capital losses relating to certain U.S. subsidiaries, $106 million are subject to an annual limitation under Internal Revenue Code Section 382. These losses expire between 2024 and 2031. As at December 31, 2011, the Company has no capital losses for income tax purposes (December 31, 2010 - $1 million, January 1, 2010 - nil). There are non-capital losses available to be carried forward of $22 million (December 31, 2010 - $18 million, January 1, 2010 - $22 million), capital losses available to be carried forward of nil (December 31, 2010 - $1 million, January 1, 2010 - nil) and other deductible temporary differences of $202 million (December 31, 2010 - $197 million, January 1, 2010 - $214 million) for which no tax benefit has been recognized. The comparative information related to losses to be carried forward and other deductible temporary differences exclude amounts associated with the assets disposed of in the year (note 8).

17. Intangible assets:

	Alberta PPAs	CPILP PPAs	Contract rights	Customer rights	Other rights	Emission credits	Software intangibles	Total
Cost								
At January 1, 2010	$ 140	$ 412	$ 105	$ 4	$ 56	$ 11	$ 12	$ 740
Additions from separate acquisition	-	-	-	-	18	16	6	40
Disposals	-	-	-	-	-	(8)	(3)	(11)
Foreign currency translation adjustments	-	(24)	(4)	-	-	-	-	(28)
Balance at December 31, 2010	$ 140	$ 388	$ 101	$ 4	$ 74	$ 19	$ 15	$ 741
Additions from separate acquisition	-	-	28	-	33	33	9	103
Disposal of CPILP (note 8)	-	(394)	(100)	-	-	-	-	(494)
Disposals	-	-	-	-	-	(20)	-	(20)
Foreign currency translation adjustments	-	6	-	-	-	-	-	6
Balance at December 31, 2011	$ 140	$ -	$ 29	$ 4	$ 107	$ 32	$ 24	$ 336
Accumulated Amortization								
At January 1, 2010	$ (6)	$ (21)	$ (9)	$ -	$ -	$ (1)	$ (1)	$ (38)
Amortization	(12)	(35)	(3)	-	-	-	(2)	(52)
Impairments, net of reversals	-	(4)	(3)	-	-	-	-	(7)
Foreign currency translation adjustments	-	7	-	-	-	-	-	7
Balance at December 31, 2010	$ (18)	$ (53)	$ (15)	$ -	$ -	$ (1)	$ (3)	$ (90)
Disposal of CPILP (note 8)	-	70	58	-	-	-	-	128
Disposals	-	-	-	-	-	-	1	1
Amortization	(13)	(16)	(1)	-	(2)	-	(3)	(35)
Impairments (note 8)	-	-	(43)	-	-	-	-	(43)
Foreign currency translation adjustments	-	(1)	-	-	-	-	-	(1)
Balance at December 31, 2011	$ (31)	$ -	$ (1)	$ -	$ (2)	$ (1)	$ (5)	$ (40)
Net book value								
At January 1, 2010	$ 134	$ 391	$ 96	$ 4	$ 56	$ 10	$ 11	$ 702
At December 31, 2010	$ 122	$ 335	$ 86	$ 4	$ 74	$ 18	$ 12	$ 651
At December 31, 2011	$ 109	$ -	$ 28	$ 4	$ 105	$ 31	$ 19	$ 296

17. Intangible assets, continued:

Acquired PPAs are recorded at the cost of acquisition. Under the terms of the Company's Sundance and Joffre PPAs (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.

The 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.

Contract rights include the cost of acquired management and operations agreements and water rights.

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 term of the contract.

Other rights include the cost of land lease agreements for use in wind power projects in Alberta, British Columbia and Ontario, coal supply access rights relating to the Keephills 3 Project and the fair value of a 20-year agreement whereby the Company will sell Renewable Energy Credits produced by the Halkirk Wind Project to a third party.

Other intangible assets include the costs of acquired software.

Impairments

Impairments of intangible assets were recognized during the year ended December 31, 2011 as described in note 8 (year ended December 31, 2010 - $8 million). Details of impairments recognized on transition to IFRS are detailed in note 37. No reversals of previous impairments of intangible assets were reversed during the year ended December 31, 2011 (year ended December 31, 2010 - $1 million).

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the year ended December 31, 2011 or 2010.

Restrictions on assets

There are no charges over the Company's intangible assets.

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

18. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment	Total
Cost				
At January 1, 2010	$ 675	$ 68	$ 2,711	$ 3,454
Acquisitions through business combinations (note 9)	-	-	218	218
Additions	324	-	44	368
Additions into service	(109)	-	109	-
Disposals and retirements	-	-	(19)	(19)
Foreign currency translation adjustments	-	-	(37)	(37)
At December 31, 2010	$ 890	$ 68	$ 3,026	$ 3,984
Acquisitions through business combinations (note 9)	-	4	622	626
Additions	445	1	38	484
Additions into service	(974)	16	958	-
Disposals and retirements	-	-	(32)	(32)
Disposal of CPILP (note 8)	(3)	(5)	(1,002)	(1,010)
Revisions to decommissioning costs	-	-	45	45
Foreign currency translation adjustments	-	-	61	61
At December 31, 2011	$ 358	$ 84	$ 3,716	$ 4,158
Accumulated Depreciation				
At January 1, 2010	$ -	$ -	$ (109)	$ (109)
Depreciation	-	-	(186)	(186)
Disposals and retirements	-	-	16	16
Foreign currency translation adjustments	-	-	9	9
Impairments, net of reversals	-	-	(36)	(36)
At December 31, 2010	$ -	$ -	$ (306)	$ (306)
Depreciation	-	-	(192)	(192)
Disposals and retirements	-	-	23	23
Disposal of CPILP (note 8)	-	-	163	163
Foreign currency translation adjustments	-	-	(4)	(4)
Balance at December 31, 2011	$ -	$ -	$ (316)	$ (316)
Net book value				
At January 1, 2010	$ 675	$ 68	$ 2,602	$ 3,345
At December 31, 2010	$ 890	$ 68	$ 2,720	$ 3,678
At December 31, 2011	$ 358	$ 84	$ 3,400	$ 3,842

Impairments

No impairments or reversals of impairments on property, plant and equipment were recognized during the year ended December 31, 2011 (year ended December 31, 2010 - $38 million of impairments and reversals of impairments of $2 million). Details of impairments recognized on transition to IFRS are detailed in note 37.

Capitalized borrowing costs

Details of borrowing costs capitalized as part of property, plant and equipment are given in note 5. The average borrowing rate used to capitalize interest during the year was 5.24% (year ended December 31, 2010 – 5.49%) for projects financed using general borrowings. For the year ended December 31, 2011 there were no projects financed using specific borrowings (year ended December 31, 2010 – no projects financed using specific borrowings).

Restrictions on assets

Details of charges over land, plant and equipment are provided in note 21.

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

19. Goodwill:

	2011	2010
Cost		
At January 1	$ 139	$ 140
Acquisitions through business combinations (note 9)	23	-
Disposal of CPILP (note 8)	(118)	-
Foreign currency translation adjustments	2	(1)
At December 31	$ 46	$ 139
Accumulated impairments		
At January 1	$ (35)	$ (12)
Disposal of CPILP (note 8)	35	-
Impairments	-	(23)
At December 31	$ -	$ (35)
Net book value		
At January 1	$ 104	$ 128
At December 31	$ 46	$ 104

The aggregate carrying amounts of goodwill allocated to the Company's CGUs are as follows:

	December 31, 2011	December 31, 2010	January 1, 2010
New England	$ 23	$ -	$ -
Southport	21	20	21
Curtis Palmer	-	28	28
Manchief	-	13	13
Williams Lake	-	10	10
Oxnard	-	10	11
Nipigon	-	9	9
Mamquam	-	9	9
Kapuskasing	-	-	10
North Bay	-	-	10
Other	2	5	7
	$ 46	$ 104	$ 128

Key assumptions used in testing recoverable amounts

The Company reviews its CGUs that contain goodwill on an annual basis, generally in the third quarter, to determine whether an impairment should be recognized. The last impairment review was completed in the third quarter of 2011 for the Southport CGU, however due to the timing of the acquisition the review for the New England CGU, which includes the Bridgeport, Tiverton, and Rumford plants was not completed until the fourth quarter of 2011, and in the second quarter of 2011 for those CGUs disposed of as described in note 8. The recoverable amount of each of the Company's CGUs has been determined based on fair value less costs to sell. This was calculated for the CPILP CGUs disposed of as described in note 8 using the negotiated selling prices less costs to sell of the CGUs. For the Southport and New England CGUs the fair value less costs to sell was determined using discounted cash flow projections consistent with the Company's long-term planning model. The long-term planning model covered initial cash flow projections over a ten year period. The Company earns revenues under long-term PPAs that extend beyond this ten year period. Cash flow projections for the period not covered by the long-term plan were included in the model.

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

19. Goodwill, continued:

Key assumptions used in the fair value less costs to sell calculations

The discounted cash flow approach used to estimate the fair value less costs to sell of the CGUs incorporated market place participant assumptions.

Growth rates of 2% were used to extrapolate cash flow projections beyond the ten year period covered by the long-term plan and did not exceed the long-term average growth rate of the industry.

Pre-tax discount rates used reflect the current market assessment of the risks specific to each CGU. The discount rate was estimated based on the average percentage of a weighted average cost of capital for the industry. This rate was further adjusted to reflect the market assessment of any risk specific to the CGU for which future estimates of cash flows have not been adjusted. Discount rates ranging from 9.9% to 13.2% were applied to the cash flow projections determined in the current year testing of recoverable amounts (December 31, 2010 – 5.9% to 7.0%, January 1, 2010 – 5.9% to 7.3%).

Impairments

No impairments were recorded in the consolidated statement of income for the year ended December 31, 2011 (year ended December 31, 2010 – $23 million). Details of impairments recognized on transition to IFRS are detailed in note 37.

20. Trade and other payables:

	December 31, 2011	December 31, 2010	January 1, 2010
Operating accruals	$ 124	$ 176	$ 247
Trade payables	55	54	28
Dividends and distributions payable	31	31	30
Accrued interest	10	21	20
	$ 220	$ 282	$ 325

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

21. Loans and borrowings:

	Effective interest rate	December 31, 2011	December 31, 2010	January 1, 2010
CPLP unsecured senior debt payable to EPCOR				
Due in 2010 at 6.95%		$ -	$ -	$ 202
Due in 2011 at 6.60%		-	202	204
Due in 2016 at 6.75%	6.16%	133	133	134
Due in 2018 at 5.80%	5.63%	164	165	165
Due between 2012 and 2018 at 9.00%	7.41%	85	119	167
Total CPLP debt payable to EPCOR		382	619	872
Less: current portion		25	234	245
		357	385	627
CPLP debt payable to non-related parties				
Unsecured senior medium-term notes, at 5.28%, due in 2020	5.34%	300	300	-
Unsecured senior medium-term notes, at 4.6%, due in 2015	4.70%	300	-	-
Unsecured senior notes (US$230), at 5.21%, due in 2021	5.29%	234	-	-
Unsecured senior notes (US$65), at 5.61%, due in 2026	5.67%	66	-	-
Non-recourse financing:				
Joffre Cogeneration Project, at fixed and floating rates, due in 2020	8.35%	41	41	41
Brown Lake Project, at 8.7%, due in 2016	7.13%	5	6	6
Revolving extendible credit facilities, at floating rates, due in 2015	2.81%	165	217	100
Total CPLP debt payable to non-related parties		1,111	564	147
Less: current portion		3	1	1
		1,108	563	146
CPILP debt				
Unsecured senior notes (US$190), at 5.90%, due in 2014		-	188	200
Unsecured senior medium-term notes, at 5.95%, due in 2036		-	204	203
Unsecured senior medium-term notes (US$150), at 5.87%, due in 2017		-	148	156
Unsecured senior medium-term notes (US$75), at 5.97%, due in 2019		-	73	77
Secured term loan, at 11.25%, due in 2010		-	-	1
Revolving extendible credit facilities, at floating rates, due in 2012		-	86	78
Total CPILP debt		-	699	715
Less: current portion		-	-	1
		-	699	714
		1,465	1,647	1,487
Less: deferred debt issue costs		13	13	15
		$ 1,452	$ 1,634	$ 1,472

21. Loans and borrowings, continued:

Unsecured senior debt payable to EPCOR

The unsecured senior debt payable to EPCOR matures between 2012 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.

CPLP unsecured senior notes

The CPLP unsecured senior medium-term notes of $300 million and $300 million are due in 2020 and 2015 respectively, with interest payable semi-annually.

The CPLP unsecured senior notes aggregating to $300 million (US$295 million) were issued in two tranches. The $234 million (US$230 million) and $66 million (US$65 million) tranches are due in 2021 and 2026 respectively 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 $75 million. Brown Lake Project financing is secured by a charge against project assets which have a carrying amount of $11 million.

CPLP revolving extendible credit facilities

Unsecured three-year credit facilities of $700 million, committed to 2015 and uncommitted amounts of $20 million, are available to the Company's subsidiary, CPLP. At December 31, 2011, the Company had $165 million in bankers' acceptances outstanding under these facilities (December 31, 2010 - $217 million, January 1, 2010 - $100 million). Additional uncommitted amounts of $5 million are available to the Company and are undrawn at December 31, 2011 (December 31, 2010 – nil, January 1, 2010 - 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, 2015. As at December 31, 2011, no amounts have been drawn on these facilities (December 31, 2010 – nil, January 1, 2010 - nil), but letters of credit of $187 million (December 31, 2010 - $122 million, January 1, 2010 - $119 million) have been issued as described in note 34.

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

21. Loans and borrowings, continued:

Under the terms of the extendible facilities, the Company's subsidiary, CPLP, may obtain advances by way of Canadian or U.S. prime loans, U.S. base rate loans, U.S. LIBOR loans and bankers' acceptances. Depending on CPLP's credit rating, amounts drawn by way of prime or base rate loans each bear interest at the prevailing Canadian Prime, U.S. Prime, or U.S. Base rate respectively, plus a spread ranging from 0.10% to 1.25%. Amounts drawn by way of U.S. LIBOR loans or bankers' acceptances bear interest at the prevailing LIBOR rate or applicable bankers' acceptance rate plus a spread ranging from 1.10% to 2.25% based on CPLP's credit rating.

22. Provisions:

	December 31, 2011	December 31, 2010	January 1, 2010
Decommissioning	$ 157	$ 124	$ 104
Employee benefits (note 23)	43	30	20
Other	30	21	20
	230	175	144
Less: current portion	33	20	8
	$ 197	$ 155	$ 136

	Decommissioning	Employee benefits	Other	Total
As at January 1, 2010	$ 104	$ 20	$ 20	$ 144
Additional liabilities incurred	18	20	8	46
Liabilities settled	(1)	(6)	-	(7)
Amounts reversed unused	-	(4)	(7)	(11)
Foreign currency translation adjustments	(1)	-	-	(1)
Unwinding of the discount	4	-	-	4
As at December 31, 2010	$ 124	$ 30	$ 21	$ 175
Additional liabilities incurred	38	31	9	78
Liabilities settled	(1)	(16)	-	(17)
Amounts reversed unused	(3)	(2)	(2)	(7)
Foreign currency translation adjustments	3	-	-	3
Revisions to decommissioning costs	45	-	-	45
Unwinding of the discount	5	-	-	5
Settlement on CPILP disposal (note 8)	(54)	-	-	(54)
Additional liabilities incurred on CPILP disposal (note 8)	-	-	2	2
As at December 31, 2011	$ 157	$ 43	$ 30	$ 230

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

22. Provisions, continued:

Decommissioning provisions

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

The Company estimates the undiscounted amount of cash flow required to settle its decommissioning obligations is approximately $324 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2012 and 2084, which reflects the anticipated useful lives of the different power plants. The majority of the payments to settle the obligations are expected to occur between 2032 and 2066 for the power generation plants and between 2012 and 2019 for sections of the Genesee coal mine. Discount rates used to calculate the carrying amount of the obligation ranged from 0.95% to 2.89%. The actual costs to settle decommissioning obligations may vary from estimates as a result of changes to contractor rates required to perform the decommissioning.

No assets have been legally restricted for settlement of these liabilities.

Other provisions

The Company holds retail and commercial natural gas customer contracts in Alberta, acquired as part of the July 1, 2009 acquisition of assets from EPCOR Utilities Inc. The future unavoidable costs of meeting the terms of these contracts are expected to exceed the economic benefits to be received under these contracts. As a result, a provision has been recorded on the consolidated statement of financial position to reflect the estimated present value of the loss on these contracts. The expected timing of settlement of these contracts range from 2012 to 2046 and the costs were discounted using risk free rates between 0.5% and 2.4%. The timing and amount of settlement of the obligation is dependent on expectations of renewal of the contracts and expectations over the forward price of gas.

23. Employee benefits:

	December 31, 2011	December 31, 2010	January 1, 2010
Post-employment benefit obligation	$ 16	$ 11	$ 8
Other non-current employee benefit obligations	9	6	6
Other current employee benefit obligations	18	13	6
	$ 43	$ 30	$ 20

Other long-term employee benefit obligation

Other employee future benefit obligations consist mainly of obligations for benefits provided to employees on long-term disability leaves, and obligations for employee incentive arrangements.

Post-employment benefit obligation

Multiemployer defined benefit pension plan and defined contribution pension plan

Over 90% of the Company's employees are either members of the Local Authority Pension Plan or the Company's registered defined contribution plans. As described in note 2(u), the majority of the Company's pension costs and obligations are accounted for as defined contribution plans.

Contributions to defined contribution plans are recorded in the consolidated statement of income as part of staff costs and employee benefits expense. The total pension expense for all defined contribution plans is given in note 4.

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

23. Employee benefits, continued:

Defined benefit pension plans

The effective date for the latest actuarial valuation of the Company's registered pension plan was July 9, 2009. The effective date for the latest actuarial valuation of the Company's supplemental pension plan was December 31, 2010. 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, 2013. The date used to measure the plan assets and accrued benefit obligation was December 31, 2011. The supplemental pension plan is a non-contributory plan that is unfunded at December 31, 2011.

The Company's registered pension 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.

Total contributions expected to be paid to the Company's post-employment defined contribution and defined benefit plans during 2012 are $15 million.

Defined benefit plan costs, assets and obligations:

	2011	2010
Current service cost	$ 3	$ 2
Interest on obligation	1	1
Expected return on plan assets	(1)	(1)
Settlement gain	(4)	-
Net benefit (gain) expense	$ (1)	$ 2
Actual return on plan assets	$ -	$ 1

Interest on the defined benefit obligation is recognized as part of finance expense. All other costs are recorded as part of staff costs and employee benefits expense as disclosed in note 4.

	December 31, 2011	December 31, 2010	January 1, 2010
Defined benefit obligations	$ 18	$ 22	$ 17
Fair value of plan assets	2	11	9
Present value of net obligations	16	11	8
Recognized liability for defined benefit obligations	$ 16	$ 11	$ 8

There were no experience adjustments for the last 3 years.

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

23. Employee benefits, continued:

Reconciliation of defined benefit obligation and fair value of plan assets:

	2011	2010
Defined benefit obligation		
Defined benefit obligation, January 1	$ 22	$ 17
Current service cost	3	2
Interest cost	1	1
Actual benefits paid	(1)	(1)
Actuarial losses	6	3
Settlements	(13)	-
Defined benefit obligation, December 31	18	22
Plan assets		
Fair value, January 1	11	9
Employer contributions	2	1
Actuarial losses	(1)	-
Expected return on plan assets	1	1
Actual benefits paid	(1)	-
Settlements	(10)	-
Fair value of assets, December 31	$ 2	$ 11

Assumptions:

	December 31, 2011	December 31, 2010	January 1, 2010
Defined benefit obligation:			
Discount rate	4.50%	5.25%	6.00%
Expected rate of salary increases	4.00%	4.00%	4.00%
Future pension increases	0.9% to 1.35%	1.00% to 1.50%	1.00% to 1.50%

	2011	2010
Net benefit expense:		
Discount rate	4.75% to 5.25%	6.00%
Expected rate of return on plan assets	6.00% to 6.25%	6.50%
Expected rate of salary increases	4.00%	4.00%
Future pension increases	0.9% to 1.35%	1.00% to 1.50%

The overall expected rate of return on pension assets is determined based on the market expectations prevailing on that date, applicable to the period over which the obligation is due to be settled. There was no significant difference between the overall expected rate of return and the actual return on plan assets for the years ended December 31, 2011 and 2010. The expected rate of return is based on the portfolio as a whole and not on the sum of the returns on individual asset categories. The return is based exclusively on historical returns, without adjustments.

The major categories of plan assets as a percentage of the fair value of total plan assets are as follows:

	December 31, 2011	December 31, 2010	January 1, 2010
Equity securities	57%	58%	63%
Debt securities	40%	39%	35%
Other assets	3%	3%	2%
Total	100%	100%	100%

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

24. Share capital:

Authorized shares

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

Issued, called up and fully paid shares

	December 31, 2011		December 31, 2010		January 1, 2010	
	Issued	Outstanding	Issued	Outstanding	Issued	Outstanding
Common shares	58,969,007	$ 1,377	30,980,500	$ 698	21,750,000	$ 477
Preferred shares, series 1	5,000,000	122	5,000,000	122	-	-
Special voting shares	38,216,000	-	47,416,000	-	56,625,000	-
Special limited voting share	1	-	1	-	1	-
		$ 1,499		$ 820		$ 477

In November 2011, a subsidiary of EPCOR exchanged 9,200,000 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 9,200,000 common shares of Capital Power at an offering price of $24.40 per common share.

In the third quarter of 2011, the Company closed an offering to sell an additional 9,200,000 common shares, to a syndicate of underwriters, at an offering price of $25.10 per common share for gross proceeds of $231 million, less underwriters' fees of $9 million. Deferred tax assets of $2 million related to the share issue costs were recorded in the common share balance.

In the first quarter of 2011, the Company closed an offering to sell 9,315,000 common shares, to a syndicate of underwriters, at an offering price of $24.90 per common share for gross proceeds of $232 million, less underwriters' fees of $9 million. Deferred tax assets of $3 million related to the share issue costs were recorded in the common share balance.

Additional issue costs incurred on the share offerings above during the year ended December 31, 2011 totaled $2 million.

24. Share capital, continued:

Subsequent to these issues of common shares by the Company, 9,200,000 and 9,315,000 additional common limited partnership units, within the first quarter and third quarter of 2011 respectively, of the Company's subsidiary, CPLP, were issued to another subsidiary of the Company.

As a result of the exchange of EPCOR's exchangeable limited partnership units and the additional issues of common limited partnership units of CPLP during the year ended December 31, 2011, EPCOR's ownership interest in CPLP was reduced to approximately 39.4% as at December 31, 2011 (December 31, 2010 – 60.5%, January 1, 2010 – 72.2%).

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.

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. Deferred tax assets of $1 million related to the share issue costs were recorded in the preferred share balance. The preferred shares 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.

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 holders 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.

For the year ended December 31, 2011, dividends of $60 million or $1.26 per share have been declared and dividends of $51 million or $1.26 per share have been paid by the Company to the common shareholders (year ended December 31, 2010 - $30 million or $1.26 per share declared and $27 million or $1.26 per share paid). For the year ended December 31, 2011, dividends of $6 million or $1.19 per share have been declared and paid by the Company to preferred shareholders (year ended December 31, 2010 – nil).

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

25. Other reserves:

Components of other comprehensive income and other reserves are established as follows:

Cash flow hedging

The cash flow hedging reserve represents the cumulative portion of gains and losses on hedging instruments deemed effective in cash flow hedges. The cumulative deferred gain or loss on the hedging instrument is reclassified to income or loss only when the hedged transaction affects the income or loss, or is included as a basis adjustment to the non-financial hedged item, consistent with the relevant accounting policy.

Cumulative translation reserve

The cumulative translation reserve for foreign operations represents the cumulative portion of gains and losses on retranslation of foreign operations that have a functional currency other than Canadian dollars. The cumulative deferred gain or loss on the foreign operation is reclassified to income or loss only on disposal of the foreign operation.

Available-for-sale assets

The available-for-sale reserve contains the cumulative net change in the fair value of the Company's available-for-sale financial assets until the investments are derecognized or sold.

Defined benefit plan actuarial gains and losses

The defined benefit plan actuarial gains and losses represent the cumulative differences between actual and expected experience and from changes in actuarial assumptions used to determine the accrued benefit obligation.

Equity settled employee benefits

The equity-settled employee benefits reserve reflects share options granted to employees under the employee share option plan. Information about share-based payments to employees is in note 28.

26. Change in non-cash working capital:

	2011	2010
Trade and other receivables	$ 74	$ 16
Inventories	3	(14)
Trade and other payables	(50)	(21)
Deferred revenue and other liabilities	4	2
Provisions	11	11
	$ 42	$ (6)

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

27. Related party balances and transactions:

Nature of transactions

Sales to and purchases between subsidiary companies are made at normal market prices. Transactions between subsidiary companies are eliminated on consolidation.

As described in note 32, the Company has a number of joint arrangements, primarily for the construction and operation of power generation facilities. The joint arrangements provide energy to the Company and the Company provides management and operation services to the arrangements. Transactions between joint arrangements are eliminated to the extent of the Company's interest in the joint arrangement.

Prior to the acquisition of assets and liabilities by the Company from EPCOR, 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. EPCOR holds 38.216 million (December 31, 2010 – 47.416 million, January 1, 2010 – 56.625 million) exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) representing approximately 39.4% of CPLP (December 31, 2010 – 60.5%, January 1, 2010 – 72.2%). The Company provides electricity to EPCOR's residential customers and EPCOR provides distribution and transmission services to the Company along with various other services pursuant to service agreements arranged with EPCOR.

Transactions and balances

The following transactions took place during the year between the Company and its related parties:

	2011	2010
Revenues – energy sales:		
EPCOR and City of Edmonton (a)	$ 273	$ 399
Energy purchases and fuel:		
EPCOR (b)	23	30
Other raw materials and operating charges:		
EPCOR (c)	2	2
Other administrative expenses:		
EPCOR (d)	5	11
Finance expense:		
EPCOR (e)	30	7

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

27. Related party balances and transactions, continued:

	December 31, 2011	December 31, 2010	January 1, 2010
Trade and other receivables from related parties:			
EPCOR and City of Edmonton (f)	$ 8	$ 52	$ 63
Other assets:			
EPCOR (g)	7	7	8
Property, plant and equipment:			
EPCOR (h)	8	44	20
Trade and other payables to related parties:			
EPCOR (i)	22	27	31
Current provisions:			
EPCOR (j)	3	4	-
Non-current provisions:			
EPCOR (j)	4	3	-
Loans and borrowings from related parties (including current portion):			
EPCOR (note 21)	382	619	872
Share capital:			
EPCOR (note 24)	-	-	-

(a) Sales of goods relate to the provision of energy sales of $239 million (year ended December 31, 2010 - $370 million) to EPCOR and its subsidiaries, and $34 million (year ended December 31, 2010 - $29 million) to the City of Edmonton.

(b) Energy purchases and fuel include energy distribution and transmission charges from subsidiaries of EPCOR.

(c) Operations and maintenance expenses from EPCOR and its subsidiaries.

(d) Administrative expenses from EPCOR and its subsidiaries. For the year ended December 31, 2011, includes the recognition of an obligation to EPCOR for future maintenance costs associated with EPCOR's Rossdale plant of $1 million (December 31, 2010 - $7 million).

(e) Net finance expenses on loans and borrowings owed to EPCOR.

(f) Trade and other receivables includes $1 million (December 31, 2010 - $44 million, January 1, 2010 - $51 million) relating to energy sales to subsidiaries of EPCOR, nil (December 31, 2010 - $2 million, January 1, 2010 - $10 million) relating to other receivables from subsidiaries of EPCOR and $7 million (December 31, 2010 - $6 million, January 1, 2010 - $2 million) related to energy sales to the City of Edmonton.

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

27. Related party balances and transactions, continued:

(g) Contributions made to subsidiaries of EPCOR for the construction of aerial and underground transmission lines.

(h) Interest on loans and borrowings from EPCOR capitalized to property, plant and equipment.

(i) Trade and other payables includes interest accrued on the loans and borrowings owed to EPCOR of $6 million (December 31, 2010 - $9 million, January 1, 2010 - $9 million) and distributions payable to EPCOR of $12 million at December 31, 2011 (December 31, 2010 - $15 million, January 1, 2010 - $18 million).

(j) The provision amounts represent an obligation to EPCOR for future maintenance costs associated with EPCOR's Rossdale plant through 2019.

In addition to the transactions disclosed above, the Company's subsidiary CPLP has recorded total distributions of $57 million to EPCOR for the year ended December 31, 2011 (year ended December 31, 2010 - $68 million). CPLP paid distributions of $60 million to EPCOR in the year ended December 31, 2011 (year ended December 31, 2010 - $71 million).

Details of the Company's acquisition of the North Carolina assets from its former subsidiary, CPILP, are disclosed in note 8.

Details of the Company's transactions with its post-employment benefit plans are disclosed in note 23.

No provisions for doubtful debts have been established against the trade and other receivables balances for any related party. No bad debt expense was recognized in relation to any transaction with a related party that occurred during the year (2010 - nil).

Details of any commitments between CPC and its related parties are detailed in note 33.

Compensation of key management personnel

	2011	2010
Short-term employee benefits	$ 5	$ 6
Post-employment benefits	1	1
Termination benefits	-	2
Share-based payments	3	3
	$ 9	$ 12

Key management personnel include certain executive officers of the Company in addition to the Directors of the Company.

28. Share-based payments:

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 Company under this plan will not exceed 5,000,000 common shares.

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 values of these options at grant date were $2.42, $2.53 and $2.63 per option for the 2010, 2011 and 2012 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $23.00 per share.

In March 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 values of these options at grant date were $2.36, $2.46 and $2.56 per option for the 2011, 2012 and 2013 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $22.50 per share.

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

28. Share-based payments, continued:

In March 2011, the Company granted 1,445,457 share purchase options with one third vesting on March 21 of each of 2012, 2013 and 2014. The fair values of these options at grant date were $2.05, $2.14 and $2.23 per option for the 2012, 2013 and 2014 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $24.90 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
Risk free interest rate	Based on Government of Canada zero-coupon yield curve at July 2, 2009, March 1, 2010 and December 31, 2010 respectively
Volatility	16 to 20% (estimated based on similar publicly-traded companies)
Dividend yield	5.06% to 5.6%

The following illustrates the movements on share purchase options during the year ended December 31, 2011:

Grant Date	Expiry Date	Exercise Price	January 1, 2011	Granted	Exercised[1]	Forfeited	December 31, 2011
July 1, 2009	July 18, 2016	$23.00	1,900,400	-	221,249	103,048	1,576,103
March 8, 2010	March 9, 2017	22.50	1,193,493	-	52,258	98,212	1,043,023
March 21, 2011	March 21, 2018	24.90	-	1,445,457	-	134,249	1,311,208

[1] The weighted average share price at the date of exercise was $25.15.

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

Grant Date	Expiry Date	Exercise Price	January 1, 2010	Granted	Exercised[1]	Forfeited	December 31, 2010
July 1, 2009	July 18, 2016	$23.00	2,183,100	-	21,500	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 ended December 31, 2011, the Company recorded compensation expenses of $3 million related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2010 - $4 million).

At December 31, 2011, 1,515,331 of the share purchase options were vested (December 31, 2010 – 633,467, January 1, 2010 - nil).

The weighted average remaining contractual life of the Company's outstanding share purchase options at December 31, 2011 is 5.3 years (December 31, 2010 - 5.8 years, January 1, 2010 – 6.6 years).

Performance Share Units

Capital Power Corporation grants 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.

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

28. Share-based payments, continued:

	2011	2010
PSUs outstanding, January 1	153,240	-
Granted	146,896	152,801
Exercised[1]	(19,416)	-
Dividends reinvested	12,650	6,321
Forfeited	(41,880)	(5,882)
PSUs outstanding, December 31	251,490	153,240

[1] The weighted average share price at the date of exercise was $24.89.

During the year ended December 31, 2011, the Company recorded compensation expenses of $2 million (year ended December 31, 2010 - $1 million) related to the outstanding PSUs in staff costs and employee benefits expense.

At December 31, 2011, none of the Company's outstanding PSUs were vested (December 31, 2010 - nil, January 1, 2010 - nil), however, participants may exercise their options early due to retirement or termination without cause.

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 ended December 31, 2011, the Company recorded compensation expenses of $1 million (year ended December 31, 2010 - $1 million) related to the outstanding DSUs in staff costs and employee benefits expense.

29. Financial instruments:

Fair values

Details of the fair values of the Company's derivative instruments are described in note 13.

The Company classifies its cash and cash equivalents as loans and receivables and measures them at amortized cost which approximates their fair values.

Trade and other receivables are classified as loans and receivables; trade and other payables 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, 2011		December 31, 2010		January 1, 2010	
	Carrying amount	Fair value	Carrying amount	Fair value	Carrying amount	Fair value
Other financial assets (note 15)						
Loans and receivables	$ 38	$ 37	$ 54	$ 52	$ 48	$ 46
Financial assets designated at fair value through income or loss (note 15)	53	53	-	-	-	-
Finance lease receivable (note 14)						
Loans and receivables	58	50	85	75	91	75
Loans and borrowings (note 21)						
Other financial liabilities (includes current portion)	1,480	1,571	1,869	1,920	1,719	1,724

29. Financial instruments, continued:

Financial assets designated at fair value through income or loss

Pursuant to the disposal of CPILP, as described in note 8, the Company received quoted equity shares of Atlantic. The fair value of the quoted equity shares is determined by reference to published price quotations in an active market.

Loans and receivables

The fair value of the Company's finance lease receivable and other loans and receivables are based on the estimated interest rates implicit in comparable lease agreements or loans plus an estimated credit spread based on the counterparty risk as at December 31, 2011, December 31, 2010 and January 1, 2010.

Available-for-sale investments

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 amounts recognized on these investments are disclosed in note 15. Pursuant to the disposal of CPILP, as described in note 8, the Company's investment in PERH was disposed of during the current year. Other 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.

Loans and borrowings

The fair value of the Company's loans and borrowings is based on determining a current yield for the Company's loans and borrowings as at December 31, 2011, December 31, 2010 and January 1, 2010. 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 loans and borrowings. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

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 statement of financial position 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.
- 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 models. 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.

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

29. Financial instruments, continued:

Fair value hierarchy, continued

- 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 statement of financial position, classified using the fair value hierarchy described above:

	December 31, 2011			
	Level 1	Level 2	Level 3	Total
Financial assets and liabilities:				
Cash and cash equivalents	$ 73	$ -	$ -	$ 73
Other financial assets	53	-	-	53
Derivative financial instruments assets				
Commodity derivatives	-	37	1	38
Derivative financial instruments liabilities				
Commodity derivatives	(1)	(63)	(2)	(66)
Interest rate derivatives	-	(8)	-	(8)
	$ (1)	$ (71)	$ (2)	$ (74)

	December 31, 2010			
	Level 1	Level 2	Level 3	Total
Financial assets and liabilities:				
Cash and cash equivalents	$ 56	$ -	$ -	$ 56
Derivative financial instruments assets				
Commodity derivatives	-	171	16	187
Foreign exchange derivatives	-	41	-	41
	$ -	$ 212	$ 16	$ 228
Derivative financial instruments liabilities				
Commodity derivatives	(3)	(193)	(4)	(200)
Foreign exchange derivatives	-	(8)	-	(8)
Interest rate derivatives	-	(6)	-	(6)
	$ (3)	$ (207)	$ (4)	$ (214)

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

29. Financial instruments, continued:

Fair value hierarchy, continued

	January 1, 2010			
	Level 1	Level 2	Level 3	Total
Financial assets and liabilities:				
Cash and cash equivalents	$ 52	$ -	$ -	$ 52
Derivative financial instruments assets				
Commodity derivatives	4	252	14	270
Foreign exchange derivatives	-	31	-	31
	$ 4	$ 283	$ 14	$ 301
Derivative financial instruments liabilities				
Commodity derivatives	(6)	(185)	(5)	(196)
Foreign exchange derivatives	-	(6)	-	(6)
	$ (6)	$ (191)	$ (5)	$ (202)

There were no significant transfers between Level 1 and 2 for the years ended December 31, 2011 and 2010.

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:

	2011	2010
Balance, January 1 (1)	$ 12	$ 9
Unrealized and realized gains (losses) included in net income (2)	(13)	7
Purchases	-	(3)
Settlements (3)	-	(1)
Balance, December 31	$ (1)	$ 12
Total unrealized (losses) gains for the year included in net income	(13)	3

(1) The fair value of derivative instruments is presented on a net basis.

(2) Gains and losses are recorded in 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.

30. 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 income 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, 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 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 income 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.

30. 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.
- 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, 2011, that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 13.

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.

30. 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 a 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, 2011, there is a 99% probability that unfavourable daily market variations would not reduce the trading portfolio by more than $4 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.

As at December 31, 2011, 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 $1 million. There would be no impact to other comprehensive income.

This sensitivity analysis excludes translation risk associated with the translation of subsidiaries that have a different functional currency to the functional currency of the Company, financial instruments that are non-monetary items, and financial instruments denominated in the functional currency in which they are transacted and measured.

30. Risk management, continued:

Market risk, continued

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating rate current and non-current loans and borrowings. The Company is exposed to interest rate risk from the possibility that changes in 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 current borrowings and other liquidity requirements. At December 31, 2011, the proportion of fixed rate loans and borrowings was approximately 89% of total loans and borrowings outstanding (December 31, 2010 – 84%, January 1, 2010 – 90%). The Company may also use derivative instruments to manage interest rate risk. At December 31, 2011, the Company held interest rate derivatives as disclosed in note 13.

Assuming that the amount and mix of fixed and floating rate loans and borrowings and net loans and borrowings remains unchanged from that held at December 31, 2011, a 100 basis point decrease or increase to interest rates would decrease or increase full year net income attributable to common shareholders by approximately $6 million and $5 million respectively and would have no direct impact on other comprehensive income.

The effect on net income does not consider the effect of an overall change in economic activity that would accompany such an increase or decrease in interest rates. There would be no impact on net income for loans and borrowings 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.

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.

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

30. Risk management, continued:

Credit risk, continued

Maximum credit risk exposure

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

	December 31, 2011	December 31, 2010	January 1, 2010
Cash and cash equivalents	$ 73	$ 56	$ 52
Trade and other receivables [1]	198	286	315
Derivative financial instruments assets [1]	38	228	301
Loans and other long-term receivables	38	54	48
Finance lease receivables	58	85	91
Loan commitments to third parties	6	6	6
	$ 411	$ 715	$ 813

[1] The Company's maximum credit exposures related to trade and other receivables and derivative financial instruments assets by major credit concentration are comprised of maximum exposures of $104 million (December 31, 2010 - $177 million, January 1, 2010 - $213 million) for generation and $132 million (December 31, 2010 - $337 million, January 1, 2010 - $403 million) for wholesale at December 31, 2011.

This table does not take into account collateral held. At December 31, 2011, the Company held cash deposits of $5 million (December 31, 2010 - $4 million, January 1, 2010 - $3 million) as security for certain counterparty trade and other receivables 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, 2011, the Company also held other forms of credit enhancement in the forms of letters of credit of $26 million (December 31, 2010 - $25 million, January 1, 2010 - $29 million), property registrations valued at $24 million (December 31, 2010 - $74 million, January 1, 2010 - $125 million) and parental guarantees of $960 million (December 31, 2010 - $825 million, January 1, 2010 - $733 million) related to the financial assets noted above. At December 31, 2011, December 31, 2010 and January 1, 2010, 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 trade and other receivables 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), financial and non-financial derivative instruments assets and long-term financing arrangements.

The credit quality and concentrations of the Company's trade and other receivables and other 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 the underlying credit risk is known.

30. Risk management, continued:

Credit risk, continued

Loans and long-term financing

At December 31, 2011 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.

Trade and other receivables and financial derivative instruments

Trade and other receivables are 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 trade and other receivables 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 arrangements 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.

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 limits, margining to reduce energy trading risks, obtaining parent company guarantees, and when appropriate taking back security from counterparties.

Trade and other receivables and allowance for doubtful accounts

Trade and other receivables 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 contract-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.

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

30. Risk management, continued:

Credit risk, continued

Trade and other receivables and allowance for doubtful accounts, continued

The aging of trade and other receivables was:

	Gross trade and other receivables	Allowance for doubtful accounts	Net trade and other receivables
Current [1]	$ 197	$ -	$ 197
Outstanding 30 - 60 days	1	-	1
Outstanding greater than 90 days	1	1	-
	$ 199	$ 1	$ 198

[1] Current amounts represent trade and other receivables 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:

	2011	2010
Balance, January 1	$ 1	$ 3
Amounts reversed unused	-	(2)
Balance, December 31	$ 1	$ 1

Bad debt expense (net of recoveries) of nil was recognized in the years ended December 31, 2011 and 2010.

At December 31, 2011, the Company held $5 million of customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers.

At December 31, 2011, there was no provision for credit losses associated with trade and other receivables from treasury, trading and energy procurement counterparties as all balances are considered to be fully collectible.

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 and private capital debt markets and equity offerings by the Company or its CPLP subsidiary.

CPC has a long-term debt rating of BBB (Outlook Negative), 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 long-term debt ratings of BBB (Outlook Negative) and BBB/stable outlook, assigned by S&P and DBRS respectively.

As at December 31, 2011, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $873 million (December 31, 2010 - $1,165 million, January 1, 2010 - $1,294), of which $848 million (December 31, 2010 - $862 million, January 1, 2010 - $600) is committed for at least three years.

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

30. Risk management, continued:

Liquidity risk, continued

In addition to the facilities noted above, the Company, through its own facilities and those of its subsidiary, CPLP, has shelf prospectuses under which it may raise funds in the form of debt or equity. As at December 31, 2011, CPC had 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, 2011, the common shares issued as described in note 24, have reduced the available amounts on the shelf prospectus by $908 million. As at December 31, 2011, the Company's subsidiary, CPLP, had 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, 2011 CPLP has drawn $600 million on the shelf prospectus by way of medium-term notes (December 31, 2010 - $300 million, January 1, 2010 - nil). In addition the Company has $125 million of preferred shares, outstanding under a short-form prospectus (December 31, 2010 - $125 million, January 1, 2010 - nil).

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and where applicable, net of financial assets that generate cash inflows to meet cash outflows on financial liabilities as at December 31, 2011:

	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:							
Loans and borrowings	$ 28	$ 19	$ 14	$ 480	$ 145	$ 803	$ 1,489
Interest payments on loans and borrowings	80	78	76	73	50	173	530
Trade and other payables[1]	210	-	-	-	-	-	210
Other current liabilities and deferred revenue	13	-	-	-	-	-	13
Loan commitments	6	-	-	-	-	-	6
Derivative financial liabilities:							
Net commodity contracts for differences	55	6	1	-	-	-	62
Total	$ 392	$ 103	$ 91	$ 553	$ 195	$ 976	$ 2,310

[1] Excluding accrued interest on loans and borrowings of $10 million.

31. 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.

The Company considers its capital structure to consist of loans and borrowings net of cash and cash equivalents and equity (which includes non-controlling interests).

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

31. Capital management, continued:

The following table represents the total capital of the Company:

	December 31, 2011	December 31, 2010	January 1, 2010
Loans and borrowings (note 21)	$ 1,480	$ 1,869	$ 1,719
Cash and cash equivalents (note 10)	(73)	(56)	(52)
Net debt	1,407	1,813	1,667
Non-controlling interests	1,072	1,779	2,123
Share capital	1,499	820	477
Retained earnings and other reserves	24	13	16
Total equity	2,595	2,612	2,616
	$ 4,002	$ 4,425	$ 4,283

The Company, through its subsidiary 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 0.8 to 1.0;
- Maintenance of senior debt to consolidated 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 net income before interest, income taxes, depreciation and amortization to finance expense, as defined in the debt agreements, of not less than 2.5 to 1.0.

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

For the year ended December 31, 2011, the Company and its subsidiaries complied with all externally imposed capital restrictions.

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

32. Investments in joint arrangements:

The Company holds 50% interest in the Genesee 3 Project and the Keephills 3 Project, and holds a 40% interest in the Joffre Cogeneration Project.

There are no contingent liabilities relating to Capital Power's interest in the joint arrangements.

Under the terms of the Company's interest in the Genesee 3 project and the Keephills 3 Project, the Company and its respective partners have guaranteed financial and performance obligations under the joint arrangements limited to $50 million and $50 million respectively.

33. Commitments and contingencies:

(a) 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 2012 is $91 million. It is expected that the annual payments over the remaining terms of the Alberta PPAs, as described in note 17, will range from $91 million to $111 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.

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

33. Commitments and contingencies, continued:

(b) Capital Power will build, own and operate the 150 MW Halkirk Wind Project located in east central Alberta for an estimated total project cost of $357 million. As at December 31, 2011 the estimated total remaining capital cost to be incurred is $174 million. Renewable Energy Credits (RECs) produced by Halkirk will be sold under a 20-year agreement with a third party. Halkirk is expected to commence commercial operations in the last half of 2012.

(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, 2011 the estimated total remaining capital cost to be incurred is $291 million. Energy generated by PDNW will be sold under a 20-year contract with the third party. PDNW is expected to commence commercial operations in 2013.

(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 cost of $455 million. As at December 31, 2011 the estimated total remaining capital cost to be incurred is $300 million. Energy generated by Quality Wind will 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 joint arrangement with two third parties to develop, construct and operate the 270 MW K2 Wind Ontario (K2) power project in southern Ontario. K2 has an expected capital cost of $874 million, which will be shared by each party equally through their equity interest in the jointly controlled entity. As at December 31, 2011 the estimated total remaining capital cost for the Company's share of the project is $287 million. Energy generated by K2 will be sold under a PPA to a third party. K2 is expected to commence commercial operations in 2014 pending regulatory and other approvals. Included in the estimated remaining capital cost to be incurred by the Company is the Company's $5 million share of a termination payment to a third party outside of this joint arrangement, for a previous contract related to the construction of wind turbines, that will be required upon receipt of regulatory approval for K2.

(f) 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 statement of financial position as derivative financial 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[1]
Within one year	$ 74	$ 3	$ 20	$ 5
Between one and five years	45	35	43	20
After five years	15	58	8	64
	$ 134	$ 96	$ 71	$ 89

[1] Operating lease amounts include $4 million per year through 2031 which will be payable to the Company's related party, EPCOR, for the leasing of office space.

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

33. Commitments and contingencies, continued:

(g) 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. 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, 2011, the Company has $13 million extended under such notes and their carrying amount of $8 million, after fair value adjustments, is included in other financial assets.

(h) The Company and its subsidiaries are subject to various 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.

34. Guarantees:

The Company, through its subsidiary CPLP, has issued letters of credit for $187 million (December 31, 2010 - $122 million, January 1, 2010 - $119) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

35. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation plants within Canada (Alberta, British Columbia and Ontario) and in the U.S. (Connecticut, Maine, North Carolina and Rhode Island), as this is how management assesses performance and determines resource allocations. The assets disposed of in November 2011, as described in note 8, operated within Canada (British Columbia and Ontario) and in the U.S. (California, Colorado, Illinois, New Jersey, New York and Washington). Since the disposal of CPILP did not represent the disposal of a separate major line of business or geographic area, the disposal of CPILP was not considered a discontinued operation.

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

	Year ended December 31, 2011				Year ended December 31, 2010			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues and other income - external	$ 1,311	$ 459	$ -	$1,770	$1,437	$ 325	$ -	$1,762
Inter-area revenues and other income	3	1	(4)	-	4	11	(15)	-
Total revenues and other income	$ 1,314	$ 460	$ (4)	$1,770	$1,441	$ 336	$ (15)	$1,762

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

35. Segment information, continued:

	As at December 31, 2011			As at December 31, 2010		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,043	$ 799	$ 3,842	$ 3,174	$ 504	$ 3,678
Intangible assets	276	20	296	373	278	651
Goodwill	-	46	46	29	75	104
Other assets	24	-	24	19	-	19
	$ 3,343	$ 865	$ 4,208	$ 3,595	$ 857	$ 4,452

	As at January 1, 2010		
	Canada	U.S.	Total
Property, plant and equipment	$ 2,790	$ 555	$ 3,345
Intangible assets	382	320	702
Goodwill	52	76	128
Other assets	20	-	20
	$ 3,244	$ 951	$ 4,195

36. Subsequent events:

Disposal of Atlantic shares

On February 10, 2012, the Company completed the sale of its Atlantic shares, acquired on disposal of CPILP as described in note 8, on a bought deal basis at a price of $14.32 per share for gross proceeds of $52 million. Since the investment is held at fair value through income or loss, no gain will be recognized on the disposal, however the disposal will result in taxes of $1 million.

Medium-term note offering

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

Canadian base shelf prospectus filing

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

37. Transition to IFRS:

As noted in note 2, this is the first annual period under which the Company's consolidated financial statements have been presented in accordance with IFRS. For all periods up to and including the period ended December 31, 2009, the Company prepared its financial statements in accordance with previous Canadian GAAP. These financial statements, for the year ended December 31, 2011 are the first annual consolidated financial statements that the Company has prepared in accordance with IFRS.

In accordance with the CICA's adoption of IFRS, the Company has prepared financial statements which comply with IFRS applicable for periods beginning on or after January 1, 2010 as described in note 2. In preparing these financial statements, the Company's opening statement of financial position was prepared as at January 1, 2010, the Company's date of transition to IFRS. This note explains the principal adjustments made by the Company in restating its Canadian GAAP statement of financial position as at January 1, 2010, and its previously published Canadian GAAP financial statements for the year ended December 31, 2010. Estimates made under IFRS as at January 1, 2010 are consistent with estimates made for the same date under previous Canadian GAAP.

37. Transition to IFRS, continued:

The Company has applied the following exemptions and exceptions in its transition from Canadian GAAP to IFRS:

Business combinations

IFRS 1 provides the option to apply IFRS 3, Business Combinations, retrospectively or prospectively from the date of transition. The retrospective basis would require restatement of all business combinations that occurred prior to the transition date. The Company has taken the IFRS 1 election to not restate previous business combinations at the date of transition. Any goodwill arising on such business combinations before the date of transition has not been adjusted from its carrying amount previously determined under Canadian GAAP as a result of applying this exemption. Goodwill and indefinite life intangibles are tested annually for impairment. Refer to the accounting policy on impairment of non-financial assets disclosed in note 2(n).

Employee benefits

The Company has elected, under IFRS 1, to recognize all cumulative actuarial gains and losses that were deferred previously under Canadian GAAP through opening retained earnings at the date of transition for all of its employee benefit plans.

Translation of foreign operations

The Company has elected, under IFRS 1, to deem the cumulative translation account for all foreign operations to be nil at the date of transition, and to reclassify all amounts determined in accordance with previous Canadian GAAP at that date to retained earnings.

Decommissioning liabilities

The Company has elected, under IFRS 1, to adopt a simplified approach, whereby the Company elected to not calculate retrospectively the effect of each change in estimate that occurred prior to the date of transition.

Fair value as deemed cost

The Company has elected, under IFRS 1, to use fair value as deemed cost on certain items of property, plant and equipment.

Adjustments to the statement of cash flows

In addition to the adjustments required for the accounting policy differences described in the following notes, interest paid, including capitalized interest, and income taxes paid and recovered have been moved into the body of the consolidated statement of cash flows within operating and financing activities. These amounts were previously disclosed as supplementary information and captured within the consolidated statement of cash flows within changes in non-cash operating working capital for expensed interest and income taxes and within payments to acquire property, plant and equipment and other assets for capitalized interest. In addition, amounts previously recorded as reductions to cash flows from operating activities, related to overhaul costs that are capitalized under IFRS, have been moved into payments to acquire property, plant and equipment and other assets. There are no other material differences between the statement of cash flows presented under IFRS and the statement of cash flows presented under Canadian GAAP.

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

37. Transition to IFRS, continued:

Reconciliation of equity

The reconciliation of equity reported under previous Canadian GAAP to equity reported under IFRS on first time adoption at January 1, 2010 (date of transition to IFRS) was:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation reclassifications (e)	IFRS
Cash and cash equivalents	$ 52	$ -	$ -	$ -	$ -	$ -	$ 52
Trade and other receivables[1]	312	1	-	-	2	-	315
Inventories	63	5	-	-	-	-	68
Derivative financial instruments assets	146	-	-	-	-	-	146
Deferred tax assets	2	-	-	-	-	(2)	-
Assets held for sale	36	-	-	-	-	-	36
Total current assets	611	6	-	-	2	(2)	617
Other assets	120	-	-	-	-	(100)	20
Derivative financial instruments assets	155	-	-	-	-	-	155
Finance lease receivables	-	-	-	-	64	27	91
Other financial assets	-	-	-	-	(3)	73	70
Deferred tax assets	61	-	-	-	(30)	2	33
Intangible assets	712	-	(10)	-	-	-	702
Property, plant and equipment	3,237	19	(28)	53	34	30	3,345
Goodwill	140	-	(12)	-	-	-	128
Total non-current assets	4,425	19	(50)	53	65	32	4,544
Total assets	$ 5,036	$ 25	$ (50)	$ 53	$ 67	$ 30	$ 5,161

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

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

37. Transition to IFRS, continued:

Reconciliation of equity continued

As at January 1, 2010:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation reclassifications (e)	IFRS
Trade and other payables	$ 339	$ -	$ -	$ -	$ -	$ (14)	$ 325
Derivative financial instruments liabilities	108	(1)	-	-	-	-	107
Loans and borrowings	247	-	-	-	-	-	247
Deferred revenue and other liabilities	8	-	-	-	-	-	8
Deferred tax liabilities	21	-	-	-	-	(21)	-
Provisions	-	(6)	-	-	-	14	8
Total current liabilities	723	(7)	-	-	-	(21)	695
Derivative financial instruments liabilities	102	(7)	-	-	-	-	95
Loans and borrowings	1,472	-	-	-	-	-	1,472
Deferred revenue and other liabilities	109	19	-	-	-	(73)	55
Deferred tax liabilities	95	-	-	-	(24)	21	92
Provisions	-	33	-	-	-	103	136
Total non-current liabilities	1,778	45	-	-	(24)	51	1,850
Share capital	477	-	-	-	-	-	477
Retained earnings	7	(2)	(6)	1	7	-	7
Other reserves	5	-	-	4	-	-	9
Equity attributable to shareholders of the Company	489	(2)	(6)	5	7	-	493
Non-controlling interests	2,046	(11)	(44)	48	84	-	2,123
Total equity	2,535	(13)	(50)	53	91	-	2,616
Total liabilities and equity	$ 5,036	$ 25	$ (50)	$ 53	$ 67	$ 30	$ 5,161

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

37. Transition to IFRS, continued:

Reconciliation of equity, continued

The reconciliation of equity reported under previous Canadian GAAP to equity under IFRS (First time adoption) at December 31, 2010 (end of comparative period) was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation reclassifications (e)	IFRS
Cash and cash equivalents	$ 56	$ -	$ -	$ -	$ -	$ -	$ 56
Trade and other receivables[1]	284	-	-	-	2	-	286
Inventories	55	5	-	-	-	-	60
Derivative financial instruments assets	152	-	-	-	-	-	152
Deferred tax assets	7	-	-	-	-	(7)	-
Assets classified as held for sale	-	-	-	-	-	-	-
Total current assets	554	5	-	-	2	(7)	554
Other assets	121	-	-	-	-	(102)	19
Derivative financial instruments assets	76	-	-	-	-	-	76
Finance lease receivables	-	-	-	-	61	24	85
Other financial assets	-	-	-	-	11	78	89
Deferred tax assets	63	-	-	-	(30)	7	40
Intangible assets	667	-	(16)	-	-	-	651
Property, plant and equipment	3,597	25	(61)	45	39	33	3,678
Goodwill	139	-	(35)	-	-	-	104
Total non-current assets	4,663	25	(112)	45	81	40	4,742
Total assets	$ 5,217	$ 30	$ (112)	$ 45	$ 83	$ 33	$ 5,296

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

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

37. Transition to IFRS, continued:

Reconciliation of equity, continued

As at December 31, 2010:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation reclassifications (e)	IFRS
Trade and other payables	$ 304	$ 4	$ -	$ -	$ -	$ (26)	$ 282
Derivative financial instruments liabilities	126	(1)	-	-	-	-	125
Loans and borrowings	235	-	-	-	-	-	235
Deferred revenue and other liabilities	10	-	-	-	-	-	10
Deferred tax liabilities	21	-	-	-	-	(21)	-
Provisions	-	(6)	-	-	-	26	20
Total current liabilities	696	(3)	-	-	-	(21)	672
Derivative financial instruments liabilities	95	(6)	-	-	-	-	89
Loans and borrowings	1,634	-	-	-	-	-	1,634
Deferred revenue and other liabilities	119	20	-	-	-	(78)	61
Deferred tax liabilities	95	-	-	-	(43)	21	73
Provisions	-	41	-	-	3	111	155
Total non-current liabilities	1,943	55	-	-	(40)	54	2,012
Share capital	820	-	-	-	-	-	820
Retained earnings	3	-	(1)	-	6	-	8
Other reserves	1	-	(3)	3	4	-	5
Equity attributable to shareholders of the Company	824	-	(4)	3	10	-	833
Non-controlling interests	1,754	(22)	(108)	42	113	-	1,779
Total equity	2,578	(22)	(112)	45	123	-	2,612
Total liabilities and equity	$ 5,217	$ 30	$ (112)	$ 45	$ 83	$ 33	$ 5,296

37. Transition to IFRS, continued:

Notes to the reconciliations

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

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

The contract between the Genesee mine operator and the Company requires the operating activities of the mine, including depreciation on the operator's share of the mine assets, to be fully funded by the Company, whereas the capital funding is shared by the two parties. As a result, certain costs that were previously capitalized would have been expensed under the requirements of IAS 16 and fully funded by Capital Power resulting in an increase to non-current deferred revenue and other liabilities of $11 million as at January 1, 2010 and an increase of $14 million as at December 31, 2010. As a result of these changes, trade and other payables of nil and $4 million were recorded as at January 1, 2010 and December 31, 2010 respectively. In addition, the Company recorded a transitional adjustment to align accounting policies between the Company and the Genesee mine operator resulting in an increase of $5 million in inventory, a decrease of $3 million to property, plant and equipment and an increase in non-current deferred revenue and other liabilities of $2 million as at January 1, 2010 through December 31, 2010.

Under Canadian GAAP, the Joffre joint venture's overhaul costs for the Joffre cogeneration facility were expensed and the joint venture's recovery of overhaul costs from one of the joint venture partners was recognized as revenue in the period that the cost was incurred. Under the requirements of IAS 16, the overhaul costs are capitalized as a component of property, plant and equipment and recoveries are recognized in income over the period that the corresponding asset is depreciated. Therefore non-current deferred revenue and other liabilities increased by $6 million and $4 million, as at January 1, 2010 and December 31, 2010 respectively, on transition to IFRS for recoveries received by the joint venture of costs that had been expensed under Canadian GAAP and reclassified to property, plant and equipment under IFRS. As a result of these changes, trade and other receivables of $1 million were recorded as at January 1, 2010.

Under IFRS, accounting for the components of property, plant and equipment is required at a more detailed level than under Canadian GAAP. IAS 16 requires separate depreciation for those components with a distinct depreciation method or rate of deprecation. As a result of applying the componentization requirements of IAS 16 effective July 1, 2009, the net book value of property, plant and equipment decreased by $5 million and $11 million, reflecting increased depreciation net of overhaul costs capitalized, as at January 1, 2010 and December 31, 2010 respectively.

IAS 37 requires provisions to be measured at the best estimate of the expected expenditure using discount rates appropriate for each liability. Under Canadian GAAP the provision was measured at fair value. Provisions are to be re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Company re-measured its decommissioning liabilities (asset retirement obligations) using revised cash flow estimates with respect to the Genesee Mine as well as for revised discount rates for all decommissioning liabilities ranging from 1.20% to 4.53% as at January 1, 2010 and 1.20% to 4.26% as at December 31, 2010. The re-measurement of the decommissioning liabilities resulted in decreases of $7 million and $7 million to the current provision and increases of $22 million and $37 million to the non-current provision as at January 1, 2010 and December 31, 2010 respectively. The re-measurement of the decommissioning liability also resulted in increases of $27 million and $39 million to the associated property, plant and equipment as at January 1, 2010 and December 31, 2010 respectively.

37. Transition to IFRS, continued:

Notes to the reconciliations, continued

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

Under IFRS, amounts provided for the unavoidable costs of the Company's Alberta retail and commercial natural gas contracts are recognized as provisions in the financial statements. Accordingly, the Company has reclassified $1 million from current derivative financial instruments liabilities to current provisions as at January 1, 2010. As well, related to these contracts, the Company recognized an additional $11 million in non-current provisions as at January 1, 2010 of which $7 million was reclassified from non-current derivative financial instruments liabilities. As a result of changes in cash flow assumptions and discount rates, the non-current provision recorded at January 1, 2010 was decreased by $7 million as at December 31, 2010. Included in the December 31, 2010 change in the non-current provision is a $1 million reduction in the January 1, 2010 reclassification from non-current derivative financial instruments liabilities.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in decreases of $2 million and nil in the equity attributable to shareholders and decreases of $11 million and $22 million to non-controlling interests as at January 1, 2010 and December 31, 2010 respectively.

(b) IAS 36 – Impairment of Assets:

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

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

In accordance with IAS 36, the Company reviewed the recoverable amount for its CGUs with allocated goodwill at both the date of transition to IFRS and as at December 31, 2010. The key assumptions used in those reviews are disclosed in note 19. For all other CGUs, management assessed whether there were any triggering events at both the date of transition to IFRS and as at December 31, 2010. Recoverable amounts were calculated on a fair value less costs to sell basis, using discounted cash flow models based on the Company's long-term planning model. As a result of the review of recoverable amounts it was determined that certain of the Company's CGUs were impaired.

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

37. Transition to IFRS, continued:

Notes to the reconciliations, continued

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

The impacts of the impairments by CGU and by line item, excluding the impacts on depreciation and foreign currency translation, as at January 1, 2010 and December 31, 2010 were:

	Goodwill		Intangible Assets		Property, plant and equipment		Total	
	December 31, 2010	January 1, 2010	December 31, 2010	January 1, 2010	December 31, 2010	January 1, 2010	December 31, 2010	January 1, 2010
CPILP manager contracts	$ -	$ -	$ 7	$ 7	$ -	$ -	$ 7	$ 7
Calstock	9	9	5	1	28	8	42	18
Greeley	-	-	-	-	7	7	7	7
Kapuskasing	10	-	2	-	5	-	17	-
Moresby Lake	2	2	-	1	-	2	2	5
Naval Training Centre	1	1	1	1	-	-	2	2
North Bay	10	-	-	-	1	-	11	-
Roxboro	-	-	-	-	11	11	11	11
Tunis	3	-	2	-	12	-	17	-
	$ 35	$ 12	$ 17	$ 10	$ 64	$ 28	$ 116	$ 50

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

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

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

The additional impairment recorded for the Calstock facility, as well as the impairments recorded for the Kapuskasing, North Bay and Tunis facilities in the third quarter of 2010 were primarily due to lower expectations for waste heat as a result of lower expected throughput on the pipeline that provides the waste heat.

The total adjustments from IAS 36, including resulting impacts on depreciation and foreign currency translation gains and losses, impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in decreases of $6 million and $4 million in the equity attributable to shareholders and decreases of $44 million and $108 million to non-controlling interests as at January 1, 2010 and December 31, 2010 respectively.

37. Transition to IFRS, continued:

Notes to the reconciliations, continued

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

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

IFRS 1 also provides an optional election on transition to IFRS which allows the use of fair value as deemed cost on items of property, plant and equipment. The Company has elected under IFRS 1 to fair value certain items of property, plant and equipment resulting in an increase to property, plant and equipment of $53 million as at January 1, 2010. As a result of the increased cost base, property, plant and equipment was impacted by higher foreign exchange and depreciation changes which resulted in a decrease of $8 million as at December 31, 2010.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in increases of $5 million and $3 million in the equity attributable to shareholders and increases of $48 million and $42 million to non-controlling interests as at January 1, 2010 and December 31, 2010 respectively.

(d) Other Impacts:

In accordance with IAS 17 – Leases, the Kingsbridge PPA was determined to be a finance lease. The transitional adjustment was a result of IAS 17 and Canadian GAAP having different qualitative guidelines in the determination of the classification of leases between operating and finance (or capital under Canadian GAAP). As a result, property, plant and equipment was decreased by $53 million, finance lease receivable was increased by $64 million, trade and other receivables was increased by $2 million and retained earnings was increased by $13 million as at January 1, 2010. Property, plant and equipment was increased and finance lease receivable was decreased by an additional $2 million as at December 31, 2010 with no net impact to equity.

In accordance with IAS 31 – Interests in Joint Ventures, the Company has concluded that it controls the Genesee mine joint venture and as a result is required to consolidate this investment under IFRS. As a result, property plant and equipment was increased by $87 million and $90 million as at January 1, 2010 and December 31, 2010 respectively, with the full amount of the changes being attributed to non-controlling interests.

The Company has elected, under IFRS 1, to recognize all actuarial gains and losses in other comprehensive income. Under Canadian GAAP, the Company recognized actuarial gains and losses into income or loss using the corridor approach whereby amounts that exceeded the corridor were recognized into income or loss over the average remaining service period of the active employees. At the date of transition, all previously unrecognized cumulative actuarial gains and losses were recognized in retained earnings. As at December 31, 2010, the provision was increased and other comprehensive income was decreased by $3 million.

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. Accordingly, other financial assets were reduced by $3 million as at January 1, 2010 and increased by $11 million as at December 31, 2010, for the difference between the fair value and the previously reported carrying amount for one of the Company's equity investments. Since these adjustments are unrealized, accumulated other comprehensive income was correspondingly decreased or increased in the respective periods.

37. Transition to IFRS, continued:

Notes to the reconciliations, continued

(d) Other Impacts, continued:

In addition to the IAS 39 impacts above, under IAS 39, hedge effectiveness testing must incorporate the entity's credit risk. The net impacts of the IAS 39 changes were increases to accumulated other comprehensive income of nil and $3 million as at January 1, 2010 and December 31, 2010 respectively, with corresponding changes to retained earnings.

The Company's share-based payments contain graded vesting provisions and as such, in accordance with IFRS 2 – Share-based payments, are treated as a series of individual awards with compensation measured and recognized separately for each tranche, within a grant, that has a different vesting date. Under GAAP, the Company treated each grant as a single award and used an average life to recognize the compensation for each grant on a straight-line basis. The net impact of the IFRS 2 change was an increase in the employee benefits reserve of $1 million as at December 31, 2010.

Other impacts also include the impact of tax on the IFRS adjustments recognized. To recognize the income tax impact of the IFRS transition adjustments, deferred tax assets were decreased by $30 million as at January 1, 2010 and December 31, 2010 and deferred tax liabilities were decreased by $24 million and $43 million as at January 1, 2010 and December 31, 2010 respectively.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in increases of $7 million and $10 million in the equity attributable to shareholders and increases of $84 million and $113 million to non-controlling interests as at January 1, 2010 and December 31, 2010 respectively.

(e) Presentation reclassifications:

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

- Financial assets must be presented separately from other assets. Accordingly, $27 million and $24 million were reclassified from other assets to finance lease receivables and $73 million and $78 million were reclassified from other assets to other financial assets as at January 1, 2010 and December 31, 2010 respectively.
- Provisions must be presented as a separate item on the statement of financial position. Accordingly, $14 million and $26 million were reclassified from accounts payable to current provisions and $103 million and $111 million were reclassified from other non-current liabilities to non-current provisions as at January 1, 2010 and December 31, 2010 respectively.
- Deferred tax balances are to be classified as non-current. Therefore, as at January 1, 2010, the current deferred tax assets and liabilities of $2 million and $21 million respectively, were reclassified to non-current deferred tax assets and liabilities respectively. As at December 31, 2010, current deferred tax assets and liabilities of $7 million and $21 million respectively, were reclassified to non-current deferred tax assets and liabilities respectively.
- International Financial Reporting Interpretations Committee (IFRIC) 18 requires that contributions received with respect to the construction of property, plant and equipment and used to provide goods or services, be classified as deferred revenue. Accordingly, $30 million and $33 million of contributions that were previously reported as reductions of property, plant and equipment were reclassified as increases in deferred revenue and other liabilities as at January 1, 2010 and December 31, 2010 respectively.

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

37. Transition to IFRS, continued:

Reconciliation of total comprehensive income

The reconciliation of total comprehensive income reported under previous Canadian GAAP for the year ended December 31, 2010 to total comprehensive income reported under IFRS was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (f)	IAS 36 Impact (g)	IFRS 1 elections (h)	Other impacts (i)	Presentation reclassifications (j)	IFRS
Revenues	$ 1,712	$ -	$ -	$ -	$ (5)	$ -	$ 1,707
Other income	48	1	-	-	2	4	55
Energy purchases and fuel	(992)	(2)	-	-	4	-	(990)
Gross income	768	(1)	-	-	1	4	772
Operations, maintenance and direct administration	(230)	-	-	-	-	230	-
Indirect administration	(133)	-	-	-	-	133	-
Other raw materials and operating charges	-	29	-	-	-	(133)	(104)
Staff costs and employee benefits expense	-	-	-	-	(1)	(174)	(175)
Depreciation and amortization	(197)	(39)	3	(3)	(7)	2	(241)
Impairments	-	-	(66)	-	-	1	(65)
Other administrative expenses	-	-	-	-	-	(57)	(57)
Property taxes	(18)	-	-	-	-	-	(18)
Foreign exchange losses	(1)	-	-	-	-	-	(1)
Operating income	189	(11)	(63)	(3)	(7)	6	111
Gains on acquisitions and disposals	30	-	-	-	-	-	30
Finance expense	(74)	2	-	-	-	(6)	(78)
Income before tax	145	(9)	(63)	(3)	(7)	-	63
Income tax (expense) recovery	(8)	-	-	-	22	-	14
Net income	137	(9)	(63)	(3)	15	-	77
Other comprehensive loss	(57)	1	1	(5)	3	-	(57)
Total comprehensive income	80	(8)	(62)	(8)	18	-	20
Attributable to:							
Non-controlling interests	75	(10)	(65)	(7)	18	-	11
Shareholders of the Company	$ 5	$ 2	$ 3	$ (1)	$ -	$ -	$ 9

37. Transition to IFRS, continued:

Notes to the reconciliations

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

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

As noted in the reconciliation of equity on transition, as a result of the Company re-measuring its commercial natural gas contracts, other income increased by $1 million for the year ended December 31, 2010.

Energy purchases and fuel costs increased by $2 million for the year ended December 31, 2010 as a result of the increase to coal costs due to costs related to the Genesee mine that were previously capitalized under previous Canadian GAAP which are expensed under IFRS.

Other raw materials and operating charges decreased by $29 million for the year ended December 31, 2010 as a result of capitalizing the overhaul costs which had previously been expensed under previous Canadian GAAP.

The impact to depreciation and amortization as a result of implementing IAS 16 is an increase of $33 million for the year ended December 31, 2010.

Depreciation and amortization expense was increased by $6 million for the year ended December 31, 2010, as a result of implementing IAS 37 which resulted in an increase in the value of decommissioning assets on transition.

Finance costs decreased by $2 million for the year ended December 31, 2010 as a result of accretion expense being lower as a result of implementing IAS 37.

(g) IAS 36 Impairments:

The Company recognized certain impairments against property, plant and equipment, intangible assets and goodwill on transition to IFRS. As a result of these impairments, the Company’s depreciation and amortization expense decreased by $3 million for the year ended December 31, 2010.

During the year ended December 31, 2010, additional asset impairments of $66 million were recorded.

(h) IFRS 1 First Time Adoption of IFRS:

As noted in the reconciliation of equity on transition, the Company elected to use the fair value at transition date as deemed cost for certain plants. As a result of this election, the Company’s depreciation and amortization expense increased by $3 million for the year ended December 31, 2010.

(i) Other Impacts:

As noted in the reconciliation of equity on transition, one of the Company’s power purchase arrangements was determined to be a finance lease which resulted in a reduction to property, plant and equipment and an increase to finance lease receivable. As such, there was a decrease in electricity sales revenues of $5 million, an increase in other income of $2 million and a decrease in depreciation and amortization of $3 million for the year ended December 31, 2010.

As noted in the reconciliation of equity on transition, the Company has concluded that it controls the Genesee mine joint venture and as a result is required to consolidate this investment under IFRS. As a result, depreciation and amortization increased by $10 million for the year ended December 31, 2010, with the full amount of the changes being attributed to non-controlling interests.

37. Transition to IFRS, continued:

Notes to the reconciliations, continued

(i) Other impacts, continued:

The impact of incorporating the Company's credit risk in the hedge effectiveness testing under IAS 39, was a decrease to energy purchases and fuel of $4 million for the year ended December 31, 2010 with an offsetting charge to other comprehensive income (OCI).

The impact of recognizing the Company's share-based payments with graded vesting provisions as a series of individual awards under IFRS 2 was an increase to staff costs and other employee benefits expense of $1 million for the year ended December 31, 2010.

As a result of the IFRS adjustments, the impact to income taxes for the year ending December 31, 2010 is a decrease in expenses of $22 million.

The remaining adjustments impact OCI:

- The impact of using Primary Energy Recycling Corporation's share price as a proxy to determine the fair value of the Company's investment in Primary Energy Recycling Holdings LLC, was an increase to OCI of $9 million (net of $4 million in income tax expense) for the year ended December 31, 2010.
- The impact of incorporating the entity's credit risk into the hedge effectiveness testing was a decrease in OCI of $4 million (net of income tax expense of nil) for the year ended December 31, 2010.
- The impact of recognizing all actuarial gains and losses in other comprehensive income as incurred was to decrease OCI by $2 million (net of income tax recovery of $1 million) for the year ended December 31, 2010.
- As a result of the adjustments made by the Company on transition and up to December 31, 2010, there was a net decrease to OCI for an increase in the unrealized losses on translating the Company's foreign operations of $3 million (net of $1 million in income tax expense) for the year ended December 31, 2010.

(j) Presentation reclassifications:

The following items have been reclassified:

- In accordance with IFRIC 18, International Financial Reporting Interpretations Committee (IFRIC) 18 requires that contributions received with respect to the construction of property, plant and equipment and used to provide goods or services, be classified as deferred revenue. Accordingly, revenue should be recorded as the contributions are realized, whereas, previously under previous Canadian GAAP, this was recorded as a reduction of depreciation. The impact was an increase to other income and an increase to depreciation expense of $4 million for the year ended December 31, 2010.
- The Company has chosen to present its statement of income by nature of expense. Certain amounts have been reclassified on the consolidated statement of income to align expenses with the revised presentation format. The most significant adjustment is to separately disclose staff costs and employee benefits expenses. This reclassification resulted in other raw materials and other administration expenses increasing by $133 million and $57 million respectively for the year ended December 31, 2010.
- In accordance with IAS 37, the unwinding of the discount on provisions should be presented as a finance expense. Under Canadian GAAP, it was presented as part of depreciation and amortization. The impact of this difference is to reclassify $6 million for the year ended December 31, 2010 from depreciation and amortization to finance expense.