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For immediate release October 30, 2009

Capital Power reports third quarter results

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX:CPX) released today its financial results for the third quarter of 2009. Net income for the third quarter 2009 was $14 million or $0.64 per share.

"Despite weak summer power prices in Alberta, our third quarter financial performance was in-line with our expectations," said Brian Vaasjo, President and Chief Executive Officer of Capital Power. "We continued to see good performance from our power plants with strong average generation plant availability of 95 per cent in the third quarter. At the Clover Bar Energy Centre, we commenced operations on a new 100-megawatt natural gas turbine in Unit 2. Based on the experience gained from the installation of Unit 2, we now expect to see Unit 3 come on-line in the first quarter of 2010, which is approximately six months ahead of schedule as well as being approximately $5 million lower than earlier estimates. Once completed, the Clover Bar facility will have a gross generation output of 243 megawatts."

"Our construction project at Keephills 3, jointly owned with TransAlta, continues to experience cost pressures which has resulted in an increase of approximately six per cent to our previous $1.8 billion total project costs estimate to $1.9 billion," continued Vaasjo. "The project schedule has also been delayed a few months with commercial operations now targeted for the second quarter 2011."

"We continue to take a leadership role in carbon capture and storage (CCS) technology through our partnership with TransAlta and Alstom Canada to develop one of the world's largest CCS projects (Project Pioneer) at the Keephills 3 plant that was announced earlier this month," stated Vaasjo. "The expected $780 million funding from the Province of Alberta and Government of Canada will help Project Pioneer work towards its goal of capturing one million tones of greenhouse gas emissions annually. In addition to Project Pioneer, we are committed to completing the front end engineering and design work on the Integrated Gasification Combined Cycle (IGCC) project at our Genesee facility. However, we do not intend to develop an IGCC facility at this time primarily because the technology is not economical in today's power price environment."

Operational and Financial Highlights(1) (unaudited)	**Three months ended Sept. 30, 2009**
(millions of dollars except per share and operational amounts)	
Electricity generation (GWh)	3,534
Generation plant availability (%)	95%
Revenues	$525
Gross margin(2)	$218
Operating margin(2)	$169
Net income	$14

Earnings per share	$0.64
Dividends declared per share	$0.315
Funds from operations(2)	$93
Capital expenditures	$108

(1) The operational and financial highlights in this press release are derived from and should be read in conjunction with Management's Discussion and Analysis and the Interim Consolidated Financial Statements for the third quarter, 2009.

(2) Gross margin, Operating margin and Funds from operations 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. Reconciliations to these non-GAAP financial measures to net income in the case of gross margin and operating margin, and cash provided by operating activities in the case of funds from operations are included at the end of this press release.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on November 2, 2009 at 11:00 am (ET) to discuss the third quarter results. The conference call dial-in numbers are: (416) 340-8061 or (866) 223-7781 (toll free). Interested parties may access the webcast on the Company's website at www.capitalpower.com. An archive of the webcast will be available on the website.

A replay of the conference call will be available following the call at: (416) 695-5800 or (800) 408-3053 (toll free) and entering pass code 2164117. The replay will be available until 11:59 p.m. (ET) on November 9, 2009.

About Capital Power

Capital Power is a growth-oriented North American independent power producer, building on more than a century of innovation and reliable performance. The Company's vision is to be recognized as one of North America's most respected, reliable and competitive power generators. Headquartered in Edmonton, Alberta, Capital Power has interests in 31 facilities in Canada and the U.S. totaling approximately 3,400 megawatts of generation capacity. Capital Power and its subsidiaries develop, acquire and optimize power generation from a wide range of energy sources.

Forward-Looking Statements

This news release contains forward-looking statements, including "forward-looking statements" within the meaning of applicable Canadian and United States securities laws, as it relates to anticipated financial performance, events and strategies. Such forward-looking statements include, without limitation, (i) the expected timing of commercial operation and project costs of Keephills 3 and Clover Bar Energy Centre Unit 3; and (ii) expected funding from the Province of Alberta and Government of Canada on Project Pioneer. Where statements by Capital Power express or imply an expectation or belief as to future events or results, such expectation or belief is expressed in good faith and believed to have a reasonable basis. However, forward-looking statements are subject to risks, uncertainties and other factors, which could cause actual results to differ materially from future results expressed, projected or implied by such forward-looking statements. Capital Power expressly disclaims any obligation to release publicly revisions to any forward looking statement to reflect events or circumstances after the date of this news release, or to reflect the occurrence of unanticipated events, except as may be required under applicable securities laws.

Non-GAAP Financial Measures

The Company uses (i) gross margin, (ii) operating margin, and (iii) funds from operations as financial performance measures. These terms are not defined financial measures according to Canadian GAAP and do not have standardized meanings prescribed by GAAP, and therefore may not be comparable to similar measures used by other enterprises.

Gross margin and operating margin

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

(unaudited, $ millions)	Three months ended Sept 30, 2009
Revenues	525
Energy purchases and fuel	307
Gross margin	**218**
Operations, maintenance, and direct administration	49
Operating margin	**169**
Deduct (add):	
Indirect administration	27
Depreciation, amortization and asset retirement accretion	44
Foreign exchange losses	3
Net financing expenses	17
Income taxes (reduction)	(2)
Non-controlling interests	66
Net income	14

Funds from operations and funds from operations excluding non-controlling interests in EPCOR Power L.P.

Capital Power uses funds from operations to measure the Company's ability to generate funds from current operations. Changes in working capital are primarily made up of intercompany payables and receivables between the Company and EPCOR and are not representative of how working capital is managed by the Company in this period of transition. Therefore, the Company uses funds from operations as its primary operating cash flow measure. The Company measures its interest in cash flows by excluding the non-controlling interest in EPCOR Power L.P.'s cash flows. A reconciliation of (i) funds from operations and (ii) funds from operations excluding non-controlling interests in EPCOR Power L.P., to cash provided by operating activities is as follows:

(unaudited, $ millions)	Three months ended Sept 30, 2009
Funds from operations excluding non-controlling interests in EPCOR Power L.P.	**$ 70**
Funds from operations due to non-controlling interests in EPCOR Power L.P.	23
Funds from operations	93
Change in non-cash operating working capital	(40)
Cash provided by operating activities	**$ 53**

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CAPITAL POWER CORPORATION
Interim Report
September 30, 2009

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated October 30, 2009, should be read in conjunction with the unaudited interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the three months ended September 30, 2009 and for the period from May 1, 2009, the date of incorporation, to September 30, 2009, the Supplemented PREP Prospectus (the Prospectus) of Capital Power Corporation dated June 25, 2009 for its initial public offering, the Company's Business Acquisition Report (BAR) dated September 16, 2009 and the cautionary statement regarding forward-looking information on page 36. In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation, together with its subsidiaries. Financial information in this MD&A is based on the unaudited interim consolidated financial statements, which are prepared in accordance with Canadian generally accepted accounting principles (GAAP), and is 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.

Capital Power was incorporated on May 1, 2009 under the *Canada Business Corporations Act* as 7166575 Canada Inc. and changed its name to Capital Power Corporation pursuant to articles of amendment dated May 6, 2009. The Company became a reporting issuer under Canadian securities regulation on June 26, 2009. On July 9, 2009, the Company completed its initial public offering (IPO) and acquisition of power generation assets and operations (the Reorganization) from EPCOR Utilities Inc. (EPCOR), as described under Significant Events. The Company's outstanding share capital on September 30, 2009 consisted of 21.75 million common shares, 56.625 million special voting shares and one special limited voting share.

The Company commenced operations in July 2009 and its first fiscal year will end on December 31, 2009. Accordingly, the Company's financial statements for the interim period ended September 30, 2009 do not include prior year comparative information. In this MD&A, the Company's financial results for the three months ended September 30, 2009 are explained by comparisons with the results for the three months ended June 30, 2009 as reported in the unaudited pro forma consolidated financial information presented in Appendix B of the BAR dated September 16, 2009. The pro forma financial statements as at and for the three months ended June 30, 2009 are based on the unaudited interim combined and consolidated financial statements of EPCOR Power Group, being substantially all of the assets of the power generation business of EPCOR conducted by certain subsidiaries and interests of EPCOR, and reflect the effects of the completion of the IPO, the Reorganization and the use of the IPO proceeds as if the IPO and Reorganization were completed on January 1, 2008 for the pro forma consolidated income statement and on June 30, 2009 for the pro forma balance sheet.

Overview

The Company is among Canada's largest independent power generation companies (as measured by revenue, total assets and capacity), and owns or operates approximately 3,400 megawatts (MW) of power generating capacity in North America. The Company's facilities consist of 31 power plants with geographic, fuel source and counterparty diversification. Many of these facilities were built and commissioned by EPCOR over the last decade, providing the Company with development and construction experience and capability. The Company is constructing 595 MW of additional generation capacity at two locations, and has other projects in various stages of development which represent approximately 1,000 MW of future capacity.

The Company's performance in the third quarter of 2009 was in line with management's expectations. Plant availability averaged 95% in the third quarter compared with 93% in the previous quarter and plant output was also higher in the third quarter. The second unit at Clover Bar Energy Centre commenced operations in September and construction continued on the Company's major construction projects including Keephills 3, EPCOR Power L.P.'s North Carolina plants and the third unit at the Clover Bar Energy Centre. The separation of Capital Power's business operations from EPCOR and subsequent transition activities also went according to plan. Net income for the third quarter was $14 million which was $3 million higher than the net income in the second quarter as disclosed in the pro forma financial information.

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:

Financial discipline

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

Strong and sustainable growth

Capital Power has a pipeline of projects under construction or development. Building on the success of Genesee 3, the Company is expanding Clover Bar Energy Centre and building the Keephills 3 facility, representing 595 MW of new generation capacity, of which Capital Power has a 348 MW ownership interest. Clover Bar Energy Centre and Keephills 3 are expected to be fully operational in 2010 and 2011, respectively. The Company also 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 will capitalize on its experience to seek to acquire high quality assets.

Technology preference

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

Regional footprint

Capital Power intends to confine its regional footprint to Canada and the U.S. and seeks to enhance its regional diversification by focusing on a select group of target markets across Canada and the U.S. Capital Power uses a disciplined approach to selecting target regions with a preference for markets with favourable reserve margins and spark spreads, regulatory frameworks conducive to competitive power generation, sufficient scale to support the establishment of a Networked Hub of power facilities and liquid trading markets. Reserve margin means the difference between power demand during peak usage periods and the total supply of power available to meet this demand for a particular power market and is generally expressed as a percentage that is calculated as total supply less the peak demand divided by total supply. Spark spread means the theoretical difference between the price of electricity as the output and its energy cost of production.

Based on these criteria for selecting target region markets, Capital Power intends to maintain its existing strong position in Alberta and initially focus on developing additional hubs in the following three regions: Mid-Atlantic U.S., including the PJM (Pennsylvania, New Jersey and Maryland) Interconnection and the Virginia-Carolinas; the Northeast U.S., including the New York Independent System Operator and the New England Power Pool; and the Southwest U.S., including the California Independent System Operator and Desert Southwest (Arizona and Nevada). In addition, other markets will be considered on a case-by-case basis if opportunities arise for the development of contracted renewable facilities or for the replication of Capital Power's supercritical coal plant hubs with an attractive counterparty in a supportive regulatory environment. For example, Capital Power expects that long-term contracts from renewable projects will be achievable in both the Ontario and British Columbia markets.

Continued focus on operational excellence, 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 the maintenance requirements of assets in order to ensure high levels of fleet availability. In addition, Capital Power is working with federal and provincial governments to develop technologies that will enhance the feasibility of near-zero emission coal-fired power generation. The Company also remains committed to a culture of zero injury and occupational illness.

Networked Hub strategy

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

Significant Events

Capital Power IPO closing

On July 9, 2009, Capital Power issued 21,750,000 common shares at $23.00 per share pursuant to the IPO. The proceeds from the IPO net of issue costs were approximately $475 million, of which approximately $468 million was used to purchase an approximate 27.8% equity interest in Capital Power L.P. (CPLP). CPLP purchased substantially all of the power generation assets of EPCOR in early July 2009 through the following series of transactions (the Reorganization):

- Formation of CPLP: Capital Power Corporation and Capital Power Holdings Inc., a wholly-owned subsidiary of Capital Power, formed CPLP. Capital Power Corporation acquired one general partner unit (GP Unit) and is the initial general partner of CPLP. Capital Power Holdings Inc. acquired one common limited partnership unit and as a result, became the initial limited partner in CPLP.
- Sale of EMCC Limited to Capital Power Corporation: EPCOR transferred all of the outstanding common shares of EMCC Limited to Capital Power Corporation in return for payment of approximately $468 million in cash.
- Contribution of Assets by EMCC Limited to CPLP: EMCC Limited contributed substantially all of its assets (consisting primarily of certain securities of subsidiary entities, its class B shares in the capital of EPLP Investments Inc. and a promissory note of EPLP Investments Inc.) to CPLP in return for 21.75 million GP Units. Capital Power Corporation transferred its GP Units in CPLP to EMCC Limited and as a result EMCC Limited became the general partner of CPLP.
- Sale of Assets by EPCOR Power Development Corporation (EPDC) to CPLP: EPDC transferred substantially all of its assets (consisting primarily of assets related to Genesee Units 1 and 2, the Genesee Coal Mine joint venture and certain interests in partnerships) to CPLP in return for 56.625 million exchangeable limited partnership units of CPLP and approximately $896 million in cash. CPLP financed the cash payment with the proceeds from a long-term debt obligation to EPCOR.

Concurrently, EPDC subscribed for 56.625 million special voting shares of Capital Power for a nominal amount.

Immediately following completion of the Reorganization, Capital Power held approximately 27.8% of CPLP while EPCOR held 56.625 million exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) representing approximately 72.2% of CPLP. Each exchangeable limited partnership unit is accompanied by a special voting share in the capital of Capital Power which entitles the holder to a vote at Capital Power shareholder meetings, subject to the restriction that such special voting shares must at all times represent not more than 49% of the votes attached to all Capital Power common shares and special voting shares, taken together. Capital Power and EPCOR have agreed that for so long as EPCOR holds not less than a 20% interest in the common shares of Capital Power, the number of directors will be not less than nine. The special voting shares also entitle EPCOR, voting separately as a class, to nominate and elect a maximum of four directors of Capital Power. There are currently twelve directors on Capital Power's board of directors. The general partner of CPLP is wholly-owned by Capital Power. Accordingly, Capital Power controls CPLP and therefore the operations of CPLP have been consolidated for financial statement purposes effective in July 2009.

Immediately following completion of the Reorganization, CPLP held 49% and EPCOR held 51% of the voting rights in EPLP Investments Inc. EPLP Investments Inc. owns the approximate 30.6% interest in EPCOR Power L.P. previously owned by EPCOR. However, CPLP is entitled to all of the economic interest in EPLP Investments Inc. Accordingly, effective in July 2009 Capital Power has consolidated the financial results of EPCOR Power L.P.

In July 2009, Capital Power entered into various agreements with EPCOR to provide for certain aspects of the separation of the business of Capital Power from EPCOR, to provide for the continuity of operations and services and to govern the ongoing relationships between the two entities and their subsidiaries.

Second new turbine at Clover Bar Energy Centre

On September 1, 2009, a new 100-megawatt (MW) natural gas-fired turbine commenced operations at our Clover Bar Energy Centre. The unit is the second of three new turbines being installed at the site and the net capacity upon completion of all three units will be 243 MW. The first unit, has a net capacity of 43 MW and commenced operation in the first quarter of 2008.

Subsequent Events

EPCOR Power Equity Ltd. $100 million preferred share issue

On October 13, 2009, EPCOR Power Equity Ltd. (EPEL), a subsidiary of EPCOR Power L.P., entered into a bought deal for the issuance of 4 million 7.0% cumulative rate reset preferred shares, Series 2 (the Series 2 Shares) at a price of $25.00 per share, for aggregate gross proceeds of $100 million (the Offering). The Series 2 Shares will pay fixed cumulative dividends of $1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate will be reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The Series 2 Shares are redeemable at $25.00 per share by the Corporation on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (Series 3 Shares) of the Corporation, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the Corporation, at a rate equal to the sum of the then 90-day Government of Canada treasury-bill rate and 4.18%. The offering is expected to close on or about November 2, 2009, subject to certain conditions. The net proceeds will be used to repay outstanding bank indebtedness.

Changes to EPCOR Power L.P. distributions

On October 13, 2009, EPCOR Power L.P. announced a change in the frequency of its distributions to monthly from quarterly. Cash distributions of EPCOR Power L.P. for periods commencing after September 30, 2009 will be made in respect of each calendar month instead of the quarters ending March, June, September and December of each year.

EPCOR Power L.P. also announced the launch of a Premium Distribution™ and Distribution Reinvestment Plan (the Plan) that provides eligible unitholders with two alternatives to receiving the monthly cash distributions, including the option to accumulate additional units in EPCOR Power L.P. by reinvesting cash distributions in additional units at a 5% discount to the average market price of such units (as defined in the Plan) on the applicable distribution payment date. Under the Premium Distribution™ component of the Plan, eligible unitholders may elect to exchange these additional units for a cash payment equal to 102% of the regular cash distribution on the applicable distribution payment date.

Keephills 3 receives funding for carbon capture and storage

Keephills 3 is a joint development and equal ownership project of Capital Power and TransAlta Corporation (TransAlta) for the construction of a 495-MW supercritical coal-fired generation plant at TransAlta's Keephills site. As part of Keephills 3, Capital Power is partnering with TransAlta and Alstom Canada (Alstom) to develop one of the world's largest carbon capture and storage (CCS) projects, Project Pioneer (Pioneer). In October, 2009, a letter of intent was signed with the Province of Alberta under which Pioneer will be eligible to receive funding from the province's $2 billion CCS fund. The Government of Canada is also contributing toward the project through its Clean Energy Fund.

Using Alstom's chilled ammonia process, Pioneer will be designed to capture one million tonnes of greenhouse gas emissions annually. Keephills 3 was designed to reduce greenhouse gas emissions 18% compared with vintage facilities and Pioneer will deliver a further 31% reduction in Keephills 3's carbon dioxide (CO_2) emissions. The second phase of front end engineering and design (FEED) for Pioneer is scheduled to be completed by June 2010 and will include detailed engineering and procurement planning. The development of Pioneer will not affect the construction schedule for Keephills 3.

Update on construction projects

As of October 30, 2009, the Board of Directors of CPC and TransAlta had approved additional funding and a revised schedule for the Keephills 3 project. The total project cost was revised from approximately $1.8 billion to approximately $1.9 billion and Capital Power's share was correspondingly revised from approximately $903 million to approximately $955 million. The increase primarily relates to additional labour required for the construction of the power island which is the portion of the plant that includes the turbine, boiler, air quality control system, water-treatment plant and control room. Commencement of the plant's commercial operations has been rescheduled from the first quarter of 2011 to the second quarter of 2011.

Construction of the final 100-MW unit at Clover Bar Energy Centre is ahead of schedule and the unit is now expected to commence operations in the first quarter of 2010 rather than the third quarter of 2010 as previously scheduled. The Company was able to capitalize on lessons learned during the construction of Unit 2 and the expected cost of all three units has been revised to approximately $278 million from approximately $284 million. The project will contribute to meeting the expected demand for additional peaking generation in Alberta and should add to the Company's cash flow once complete. In addition, these new high-efficiency units are designed to use 85% less water and produce 70% less nitrogen oxides (NOx) than the four turbines in the old Clover Bar plant which was decommissioned in 2007.

In addition to the Pioneer project, Capital Power is committed to completing the FEED work on its pre-combustion CCS project (the Genesee Integrated Gasification Combined Cycle (IGCC) power plant). The FEED project is being conducted in conjunction with the Canadian Clean Power Coalition, in partnership with the Alberta Energy Research Institute and Natural Resources Canada. However, Capital Power does not intend to develop an IGCC facility at this time, primarily because the technology is not economical in today's power price environment. Although, the IGCC project is no longer being considered for funding from the Province of Alberta's CCS fund, the FEED study results will provide a basis for potential future development of a gasification and CCS plant.

Summary of Financial and Other Information

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

Alberta commercial plants and portfolio optimization

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

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

Alberta contracted plants

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

Ontario and British Columbia contracted plants

Ontario and British Columbia contracted plants include the Kingsbridge and Port Albert wind farms in Ontario and the Brown Lake and Miller Creek hydro facilities in British Columbia. Revenues from these plants are earned under contracts with the Ontario Power Authority and BC Hydro and consist of sales of committed amounts of energy (firm energy sales) and sales of energy generated in excess of the firm commitment amount (excess energy sales).

EPCOR Power L.P. plants

EPCOR Power L.P. plants consist of a fleet of 20 facilities located in Canada and the U.S. with PPAs and fuel supply contracts that provide stable cash flows. The Company owns 30.6% of the limited partnership units of EPCOR Power L.P. and consolidates EPCOR Power L.P. in its financial statements. In this MD&A the EPCOR Power L.P. facilities are discussed on a combined basis rather than individually unless otherwise stated. EPCOR Power L.P.'s plants are all contracted.

Other portfolio facilities

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

Unrealized changes in fair value of derivative instruments

The Company's financial results for the Alberta commercial plants and EPCOR Power L.P. plants include unrealized changes in the fair value of derivative instruments and natural gas inventory held for trading. The

Company believes that these unrealized fair value changes are not representative of the instruments' or inventory's underlying economic value without considering them in conjunction with the economically hedged items to which they relate, such as natural gas required for future plant operations, future power sales, and future cash flows denominated in foreign currencies. While the changes in the fair value of the derivatives used to hedge the exposures are recognized in net income in each reporting period, the changes in the fair value of the associated economically hedged exposures are not. Accordingly, derivative instruments that are recorded at fair value for accounting purposes can produce volatility in net income as a result of changes in forward commodity prices, foreign exchange rates and interest rates which does not necessarily represent the underlying economics of the hedging transactions.

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

Generation volume information

(unaudited, GWh)	Three months ended	
Electricity generation	Sept 30, 2009	June 30, 2009
Alberta commercial plants		
Genesee 3	470	464
Joffre	89	57
Clover Bar Energy Centre 1 and 2[1]	16	4
Taylor Coulee Chute	12	7
Clover Bar Landfill Gas	9	8
Weather Dancer	-	1
	596	541
Alberta contracted plants	1,638	1,623
Ontario and British Columbia contracted plants		
Kingsbridge 1 and Port Albert	14	25
Miller Creek	47	29
Brown Lake	11	13
	72	67
EPCOR Power L.P. plants[2]	1,228	1,030
Total	**3,534**	**3,261**

(1) Clover Bar Energy Centre includes Unit 2 as of its commercial operation date, September 1, 2009.
(2) EPCOR Power L.P. plants exclude Castleton which was sold on May 26, 2009.

(unaudited)	Three months ended	
Generation plant availability[1]	Sept 30, 2009	June 30, 2009
Alberta commercial plants		
Genesee 3	97%	98%
Joffre	96%	82%
Clover Bar Energy Centre 1 and 2[2]	75%	100%
Taylor Coulee Chute	100%	100%
Clover Bar Landfill Gas	90%	83%
Weather Dancer	55%	82%
	95%	94%
Alberta contracted plants		
Genesee 1	100%	99%
Genesee 2	95%	99%
	97%	99%
Ontario and British Columbia contracted plants		
Kingsbridge 1 and Port Albert	99%	100%
Miller Creek	88%	97%
Brown Lake	97%	97%
	94%	98%
EPCOR Power L.P. plants[3]	93%	90%
Average[3]	**95%**	**93%**

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

(2) Clover Bar Energy Centre includes Unit 2 as of its commercial operation date, September 1, 2009.

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

The increase in electricity generation in the third quarter of 2009 over the previous quarter primarily relates to the Joffre plant and the northwestern U.S. plants owned by EPCOR Power L.P. The increase for Joffre was due to two planned outages in the second quarter compared with no planned outages in the third quarter. The increase for the northwestern U.S. plants primarily relates to the Frederickson plant which is subject to a tolling arrangement with three Washington Sate public utility districts (PUDs) whereby plant dispatch is determined by the PUDs. Availability at Clover Bar Energy Centre in the third quarter includes Unit 2 as of the date of commercial operation. The unit was declared unavailable when an operator was not on site which was during the off-peak hours when it was not economical to run. Its availability will increase once the unit can be operated remotely.

Financial highlights

(unaudited, $ millions, except earnings per share)	Three months ended Sept 30, 2009	Three months ended June 30, 2009[2]
Revenues	525	537
Gross margin [1]	218	250
Operating margin [1]	169	176
Net income	14	11
Earnings per share	$ 0.64	
Fully diluted earnings per share [3]	$ 0.59	
Cash provided by operating activities [4]	-	
Capital expenditures	108	125
Long-term debt including current portion	1,771	1,762
Total assets	4,918	4,853

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

(2) Financial highlights for the three months ended June 30, 2009 are as reported in the pro forma consolidated financial information included in the BAR.

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

(4) The pro forma financial information does not include a statement of cash flows or earnings per share.

Consolidated Net Income

(unaudited, $ millions)		
Net income for the three months ended June 30, 2009[1]		**$ 11**
Higher Alberta contracted plants operating margin	7	
Higher unrealized changes in the fair value of CPLP's derivative instruments and natural gas trading inventory held for trading	5	
Lower unrealized changes in the fair value of EPCOR Power L.P.'s derivative instruments	(21)	
Higher net financing expenses	(9)	
Other	3	
Lower income taxes	13	
	(2)	
Lower (higher) non-controlling interests:		
- CPLP	(4)	
- EPCOR Power L.P.	10	
- Preferred share dividends paid by subsidiary company	(1)	
Increase in net income	3	3
Net income for the three months ended September 30, 2009		**$ 14**

(1) Net income for the three months ended June 30, 2009 is the pro forma consolidated net income as reported in the pro forma consolidated financial information included in the BAR.

Net income increased $3 million for the quarter ended September 30, 2009 compared with the previous quarter due to the net impact of the following:

- The operating margin for the Alberta contracted plants was higher primarily due to transition costs incurred in the second quarter for the Reorganization.
- The unrealized changes in the fair value of CPLP's derivative instruments and natural gas inventory held for trading that were not designated as hedges for accounting purposes were higher primarily due to the impact of decreases in Alberta forward power prices on a net short position for these derivatives in the third quarter of 2009.

- The unrealized changes in the fair value of EPCOR Power L.P.'s derivative contracts that were not designated as hedges for accounting purposes were lower primarily due to the impact of decreases in forward natural gas prices on the fair value of natural gas supply contracts.
- Financing expenses for the third quarter were in accordance with expectations. The $9 million variance from the pro forma financial information for the second quarter primarily relates to the allocation of the pro forma interest expense adjustment between the first and second quarters of 2009.
- Income taxes were lower primarily due to an out-of-period adjustment of $10 million recorded in the third quarter of 2009 to recognize net future income tax assets associated with EPCOR Power L.P.'s interest in Primary Energy Recycling Holdings LLC (PERH), an indirect subsidiary of EPCOR Power L.P. PERH is treated as a partnership for U.S. tax purposes and the adjustments are attributable to the allocation of tax deductions between EPCOR Power L.P. and PERH's other partner, Primary Energy Recycling Corporation (PERC), that were incorrectly calculated by PERH's external tax advisors for the relevant periods. Of the $10 million, $3 million is attributable to 2007, $6 million is attributable to 2008 and $1 million is attributable to the six months ended June 30, 2009.
- Non-controlling interests reflect higher income from CPLP and lower income from EPCOR Power L.P. in the third quarter of 2009 compared with the second quarter of 2009.

Results by Plant Category

(unaudited, $ millions)	Three months ended	
	Sept 30, 2009	June 30, 2009
Revenues[(2)]		
Alberta commercial plants and portfolio optimization	$ 228	$ 233
Alberta contracted plants	70	68
Ontario and British Columbia contracted plants	4	4
EPCOR Power L.P. plants	123	134
Other portfolio activities	13	61
Inter-plant category eliminations	(10)	-
	428	500
Unrealized fair value changes in derivative instruments		
- CPLP	64	3
- EPCOR Power L.P.	33	34
	97	37
	$ 525	**$ 537**
Gross margin[(1)(2)]		
Alberta commercial plants and portfolio optimization	$ 50	$ 55
Alberta contracted plants	58	57
Ontario and British Columbia contracted plants	4	4
EPCOR Power L.P. plants	77	83
Other portfolio activities	8	8
Inter-plant category eliminations	(8)	(2)
	189	205
Unrealized fair value changes in derivative instruments		
- CPLP	16	12
- EPCOR Power L.P.	13	33
	29	45
	$ 218	**$ 250**
Operating margin[(1)(3)]		
Alberta commercial plants and portfolio optimization	$ 41	$ 39
Alberta contracted plants	47	40
Ontario and British Columbia contracted plants	3	3
EPCOR Power L.P. plants	48	47
Other portfolio activities	2	2
Inter-plant category eliminations	(1)	-
	140	131
Unrealized fair value changes in derivative instruments		
- CPLP	16	12
- EPCOR Power L.P.	13	33
	29	45
	$ 169	**$ 176**

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

(2) Revenues and gross margin for the quarter ended June 30, 2009 are as reported in the pro forma consolidated financial information included in the BAR.

(3) The Company commenced using operating margin as a measure of plant performance on July 1, 2009. Accordingly, the pro forma consolidated financial information for the three months ended June 30, 2009 has been restated to conform to the presentation adopted in the third quarter of 2009. See Non-GAAP Financial Measures.

	Three months ended	
	Sept 30, 2009	June 30, 2009
Spot Prices		
Alberta power ($/MWh)(1)	49.49	32.30
Eastern region power ($/MWh)(1)	21.94	23.00
Western region power (Mid-C) ($/MWh)(1)	35.67	26.72
Alberta natural gas (AECO) ($/Gj)(2)	2.81	3.38

Capital Power's Alberta portfolio captured power price ($/MWh)(1), (3)	53.85	57.60

(1) Megawatt hours (MWh)

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

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

Alberta commercial plants and portfolio optimization

Alberta power prices averaged $49/MWh in the third quarter of 2009 compared with $32/MWh in the second quarter. The increase in the Alberta spot price was primarily due to planned outages in the province including Sundance 5 which is one of Capital Power's acquired PPAs. The Company's average realized price for commercial contracted sales and portfolio hedging activities was $54/MWh for the third quarter and $58/MWh in the second quarter. The captured power price decreased despite higher spot prices in the third quarter primarily because more of the volume in the second quarter was sold forward with lower exposure to spot prices. .

Revenues and operating margin from the Alberta commercial plants and portfolio optimization decreased $5 million primarily due to the lower captured power price in the third quarter of 2009 compared with the previous quarter. Operating margin from Alberta commercial plants and portfolio optimization increased by $2 million primarily due to transition costs for the Reorganization and business development costs incurred in the second quarter.

Alberta contracted plants

Genesee 1 and 2 operated according to expectations in the third quarter of 2009 with financial results consistent with their results for the second quarter. There was a short unplanned outage at Genesee 2 in September due to a tube leak which had a small unfavourable impact on operating income. Revenues increased primarily due to a higher recovery from the Alberta Balancing Pool for greenhouse gas emission charges paid to the Alberta Electric System Operator. Operating expenses decreased primarily due to transition costs incurred in the second quarter for the Reorganization, partly offset by increased greenhouse gas emission charges.

Ontario and British Columbia contracted plants

The Ontario and British Columbia plants performed as expected in the third quarter of 2009.

EPCOR Power L.P. plants

Generation from the EPCOR Power L.P. plants increased in the third quarter of 2009 over the previous quarter primarily due to the Frederickson plant. The increase in generation had minimal impact on revenues because revenues for the Frederickson plant primarily consist of fixed capacity payments which are not dependent on the amount of generation. Revenues for the EPCOR Power L.P. plants decreased $10 million due to normal seasonal variances including lower water volumes at the hydro facilities and lower contractual prices for the power produced by the Ontario plants, partly offset by higher capacity payments under the Naval contracts and summer performance bonuses earned by all the California plants.

Fuel costs for the EPCOR Power L.P. plants decreased $5 million primarily due to lower natural gas prices. Operations and maintenance costs decreased $5 million primarily due to an annual maintenance outage at Williams Lake and repairs completed at the North Carolina plants in the second quarter.

Other portfolio activities

The 2009 third quarter financial results for other portfolio activities were in accordance with expectations and were consistent with the previous quarter. The $48 million decrease in revenues reflects a difference in accounting for the recognition of speculative physical natural gas trading. Capital Power records the gross margin earned on the settlement of these trades on a net basis in revenues whereas the unaudited pro forma consolidated financial information for the quarter ended June 30, 2009 reflects the gross amounts of revenue and cost of natural gas associated with these trades on the respective income statement lines.

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

Revenues and expenses for unrealized changes in the fair value of derivative instruments and natural gas inventory held for trading increased $60 million and $76 million, respectively in the quarter ended September 30, 2009 compared with the quarter ended June 30, 2009. The increases were primarily due to decreases in the forward electricity and natural gas prices relative to the prices of derivative energy sales and purchase contracts that were not designated as hedges for accounting purposes.

The gross margin for changes in the fair value of derivative instruments and natural gas inventory decreased $16 million in the quarter ended September 30, 2009 compared with the quarter ended June 30, 2009, primarily due to a decrease in the fair value of EPCOR Power L.P. natural gas supply contracts in the third quarter resulting from a decrease in forward natural gas prices. This was partly offset by a higher increase in the third quarter in the fair value of derivative electricity contracts that were not designated as hedges for accounting purposes resulting from a net short position for these contracts combined with decreases in forward Alberta power prices. On July 31, 2009, EPCOR Power L.P. designated certain of its natural gas supply contracts as hedges for accounting purposes. The fair value of these contracts increased $4 million in the period from August 1, 2009 to September 30, 2009 and this gain was recorded in other comprehensive income.

Consolidated Other Expenses

(unaudited, $ millions)	Three months ended	
	Sept 30, 2009	June 30, 2009
Indirect administration(2)	27	29
Depreciation, amortization and asset retirement accretion(1)	44	44
Foreign exchange losses(1)	3	2
Net financing(1)	17	8
Income taxes (reductions)(1)	(2)	11
Non-controlling interests(1)		
- CPLP	44	40
- EPCOR Power L.P.	20	30
- Preferred share dividends paid by EPEL(3)	2	1

(1) For the three months ended June 30, 2009, consolidated other expenses, except for indirect administration, are as reported in the pro forma consolidated financial information included in the BAR.

(2) The pro forma consolidated financial information for the three months ended June 30, 2009 has been restated to conform to the presentation adopted in the third quarter where indirect administration is separated from plant results. See Non-GAAP Financial Measures.

(3) EPEL is a subsidiary of EPCOR Power L.P. See Subsequent Events.

Indirect administration

Indirect administration expenses include the cost of support departments and services such as treasury, finance, internal audit, legal, human resources, corporate risk management and health and safety, as well as business development expenses including CCS and IGCC projects. In the third quarter of 2009, indirect administration expenses were slightly lower than the previous quarter primarily due to lower business development expenses.

Foreign exchange losses

Foreign exchange loss recorded during the quarter ended September 30, 2009 reflects the strengthening Canadian dollar relative to the U.S. dollar resulting in losses on the translation of U.S. monetary assets and liabilities of certain U.S. subsidiaries of the Company.

Net financing

Financing expenses for the third quarter of 2009 were in accordance with expectations. The $9 million variance from the pro forma financial information for the second quarter primarily relates to the allocation of the pro forma interest expense adjustment between the first and second quarters of 2009.

Income taxes

Income taxes for the third quarter of 2009 were lower than for the second quarter primarily due to a future income tax recovery recognized in the third quarter relating to adjustments in taxable income calculations for prior years for EPCOR Power L.P.

Non-controlling interests

The non-controlling interests in EPCOR Power L.P. reflect approximately 69.4% of the income from EPCOR Power L.P. which was lower in the third quarter of 2009 than the previous quarter. The non-controlling interests in CPLP reflect approximately 72.2% of the income from CPLP which was higher in the third quarter than the previous quarter.

Income from CPLP includes approximately 30.6% of the income from EPCOR Power L.P. Therefore the non-controlling interests in CPLP include 22.1% (72.2% of 30.6%) of the income from EPCOR Power L.P.

Non-GAAP Financial Measures

The Company uses (i) gross margin, (ii) operating margin, (iii) funds from operations, and (iv) funds from operations excluding non-controlling interests in EPCOR Power L.P. as financial performance measures. These terms are not defined financial measures according to Canadian 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 earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with Canadian GAAP. Rather, these measures are provided to complement Canadian GAAP measures in the analysis of the Company's results of operations from management's perspective.

Gross margin and operating margin

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

(unaudited, $ millions)	Three months ended	
	Sept 30, 2009	June 30, 2009
Revenues	525	537
Energy purchases and fuel	307	287
Gross margin	**218**	**250**
Operations, maintenance, and direct administration	49	74
Operating margin	**169**	**176**
Deduct (add):		
Indirect administration	27	29
Depreciation, amortization and asset retirement accretion	44	44
Foreign exchange losses	3	2
Net financing expenses	17	8
Income taxes (reduction)	(2)	11
Non-controlling interests	66	71
Net income	14	11

In the Prospectus and BAR, the Company used adjusted earnings before foreign exchange, interest, income tax, depreciation and amortization and impairments (adjusted EBITDA) to measure plant operating performance. Commencing with the third quarter of 2009, the Company adopted operating margin rather than adjusted EBITDA to measure plant performance. Operating margin is more representative of plant performance as it excludes corporate administration and business development expenses (indirect administration).

Funds from operations and funds from operations excluding non-controlling interests in EPCOR Power L.P.

Capital Power uses funds from operations to measure the Company's ability to generate funds from current operations. Changes in working capital are primarily made up of intercompany payables and receivables between the Company and EPCOR and are not representative of how working capital is managed by the Company in this period of transition. Therefore, the Company uses funds from operations as its primary operating cash flow measure. The Company measures its interest in cash flows by excluding the non-controlling interest in EPCOR Power L.P.'s cash flows. A reconciliation of (i) funds from operations and (ii) funds from operations excluding non-controlling interests in EPCOR Power L.P., to cash provided by operating activities is as follows:

(unaudited, $ millions)	Three months ended Sept 30, 2009
Funds from operations excluding non-controlling interests in EPCOR Power L.P.	**$ 70**
Funds from operations due to non-controlling interests in EPCOR Power L.P.	23
Funds from operations	93
Change in non-cash operating working capital	(40)
Cash provided by operating activities	**$ 53**

Balance Sheet

Changes in consolidated assets: June 30, 2009 and September 30, 2009					
(unaudited, $ millions)	June 30, 2009	Acquisition	Increase (decrease)	Sept 30, 2009	Explanation of increase (decrease)
Cash and cash equivalents	$ -	$ 71	(7)	64	Refer to cash flows summary below.
Accounts receivable (including income taxes recoverable)	-	233	35	268	Receivables from EPCOR for operations during transition and higher receivables for wholesale and RRT sales and for generation sales to the Alberta Balancing Pool due to higher power pool prices in September compared with June.
Derivative instruments assets (current)	-	140	8	148	Increase in fair value of derivative instrument power, natural gas and forward foreign exchange contracts.
Other current assets	-	64	8	72	Increase in small parts, consumables and wood waste inventories and prepaid expenses.
Property, plant and equipment	-	3,163	36	3,199	Capital expenditures partly offset by depreciation and amortization expense and the impact of the strengthening Canadian dollar on the translation of property, plant and equipment of U.S. subsidiaries.
Power purchase arrangements	-	572	(36)	536	Amortization and the impact of the strengthening Canadian dollar on the translation of PPAs of U.S. subsidiaries.
Contract and customer rights and other intangible assets	-	179	2	181	
Derivative instruments assets (non-current)	-	74	64	138	Increase in the fair value of derivative power sales and forward foreign exchange contracts.
Future income tax assets (non-current)	-	57	(17)	40	The net change in future income tax assets and liabilities was primarily due to the tax impact of the out-of-period adjustment relating to EPCOR Power L.P.'s investment in PERH.
Goodwill	-	123	(4)	119	
Other assets	-	122	(5)	117	
Assets held for sale	-	36	-	36	

Changes in consolidated liabilities and shareholders' equity: June 30, 2009 and September 30, 2009					
(unaudited, $ millions)	June 30, 2009	Acquisition	Increase (decrease)	Sept 30, 2009	Explanation of increase (decrease)
Accounts payable and accrued liabilities	$ -	$ 261	$ 14	$ 275	Accrued interest on long-term debt.
Derivative instruments liabilities (current)	-	143	(19)	124	Increase in the fair value of natural gas supply contracts and forward foreign exchange contracts.
Other current liabilities	-	10	16	26	The net change in future income tax assets and liabilities was primarily due to the tax impact of the out-of-period adjustment relating to EPCOR Power L.P.'s investment in PERH.
Long-term debt (including current portion)	-	1,761	10	1,771	Draws on credit facilities, partly offset by the impact of foreign currency translation on EPCOR Power L.P.'s U.S. dollar debt and scheduled repayments of long-term debt payable to EPCOR.
Derivative instruments liabilities (non-current)	-	64	31	95	Decrease in the fair value of natural gas supply and derivative power contracts, partly offset by an increase in the fair value of forward foreign exchange contracts.
Other non-current liabilities	-	99	-	99	
Future income tax liabilities (non-current)	-	93	(34)	59	The net change in future income tax assets and liabilities was primarily due to the tax impact of the out-of-period adjustment relating to EPCOR Power L.P.'s investment in PERH.
Non-controlling interests	-	1,935	40	1,975	Non-controlling interests' share of CPLP and EPCOR Power L.P. net income and other comprehensive income, partly offset by non-controlling interests' share in EPCOR Power L.P. distributions.
Shareholders' equity	-	477	17	494	Net income and other comprehensive income.

Liquidity and Capital Resources

Cash inflows (outflows)

(unaudited, $ millions)	Three months ended Sept 30, 2009 Acquisition and reorganization	Other	Total	
Funds from Operations[1]	$ -	$ 93	$ 93	
Investing	(1,293)	(108)	(1,401)	Capital expenditures, primarily for property plant and equipment.
Financing	1,456	(41)	1,415	Acquisition and reorganization - issue of long-term debt and common shares, net of issue costs. Other - scheduled repayments of long-term debt.

(1) Cash inflows and outflows, except funds from operations, have been prepared in accordance with Canadian GAAP. See Non-GAAP Financial Measures.

Upon closing of the IPO, CPLP had credit facilities of approximately $1,220 million, of which $500 million may be utilized for issuing letters of credit. On September 30, 2009, $1,052 million remained available under these facilities. Also on September 30, 2009, EPCOR Power L.P. had revolving credit facilities of approximately $366 million, of which $224 million remained available and Capital Power had an undrawn bank line of credit of $5 million.

Upon closing of the IPO, CPLP had obligations to pay $943 million pursuant to long-term debt agreements and on June 30, 2009 EPCOR Power L.P. had obligations to pay $811 million pursuant to long-term debt agreements. In September, CPLP made a $39 million repayment on the long-term debt owing to EPCOR. Long-term debt outstanding at September 30, 2009 consisted of the following:

(unaudited)	Carrying amount ($ millions)	Maturity date	Nominal interest rate
Long-term debt payable to EPCOR	$ 876	Ranging from 2009 to 2018	Ranging from 5.80% to 9.00%
Joffre Cogeneration and Brown Lake project non-recourse financing	48	2020 and 2016	Fixed 8.59% and 8.70% and floating[1]
CPLP revolving extendible credit facilities	77	2011	0.40%
EPCOR Power L.P. long-term debt	786	Ranging from 2009 to 2036	Fixed ranging from 5.87% to 11.25% and floating[1]
	$ 1,787		

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

CPLP will be required to make principal repayments of $247 million in 2010 under terms of its long-term debt agreements. The long-term debt payable to EPCOR was issued in connection with the Reorganization pursuant to a credit agreement entered into by CPLP and EPCOR on July 9, 2009. Some of the indebtedness of CPLP to EPCOR mirrors certain debt obligations of EPCOR to the public and has repayment and interest rate terms that correspond with EPCOR's mirrored debt. The remainder of the indebtedness of CPLP to EPCOR includes an amount sufficient to meet certain debt obligations of EPCOR to The City of Edmonton, and will be repaid in accordance with an amortization schedule. On or after December 2, 2012, if EPCOR no longer owns, directly or indirectly, at least 20% of the outstanding limited partnership units of CPLP, then EPCOR may, by written notice to CPLP, require repayment of all or any portion of the outstanding principal amount under the credit agreement and accrued interest thereon, within 180 to 365 days depending on the amount outstanding. The long-term debt payable to EPCOR requires CPLP to meet certain financial covenants under the credit agreement.

CPLP's credit facilities include an extendible revolving syndicated bank credit facility (Syndicated Facility) of up to $700 million with an initial term of three years and an extendible revolving club credit facility (Club Facility) of up to $500 million with an initial 364 day period following which any drawn portion of the facility will convert into a non-revolving facility for a one year term-out period. Borrowings and repayments under the Club Facility will be made by CPLP with each lender on an individual lender basis up to that lender's commitment, and not on a pro-rata basis. The terms of these credit facilities include financial covenants and provisions for default and change of control, as more fully described in the Prospectus. Capital Power also has revolving demand credit facilities totaling $25 million.

At September 30, 2009, EPCOR Power L.P.'s credit facilities included two revolving facilities of $100 million each with terms expiring in September 2010 and October 2011, and a revolving facility of $125 million expiring in June 2011. In October, the facility expiring in 2010 was extended by one year to September 2011. The two $100 million facilities were also amended in October 2009 to add a U.S. co-borrower to facilitate funding of capital expenditures at the partnership's U.S. plants. EPCOR Power L.P. also has two demand facilities, one for $20 million and the other for US$20 million.

The committed bank credit facilities are expected to be used primarily for the purposes of providing funds for capital expenditures, letters of credit and general corporate purposes. Letters of credit are issued to meet conditions of certain debt and service agreements, to meet the credit requirements of energy market participants and to satisfy legislated reclamation requirements. On September 30, 2009, EPCOR Power L.P. had $142 million of long-term debt borrowings and less than $1 million of letters of credit outstanding under its credit facilities. At September 30, 2009, CPLP had $77 million of debt and $90 million of letters of credit outstanding under its credit facilities.

CPLP's corporate credit rating provided by S&P and DBRS is BBB. The BBB debt rating is S&P's and DBRS' 4th highest rating out of ten rating categories. According to the S&P rating system, debt rated BBB exhibits adequate protection parameters. According to the DBRS rating system, an obligation rated BBB is of an adequate credit quality with the protection of interest and principal considered to be acceptable.

Further information respecting the credit ratings assigned by these agencies is included in the Prospectus. Having an investment grade credit rating impacts CPLP's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

(unaudited, $ millions)	Three months ended Sept 30, 2009
Capital expenditures	
Keephills 3	$ 60
EPCOR Power L.P.'s North Carolina plants enhancement project	24
Clover Bar Energy Centre	8
EPCOR Power L.P.'s Oxnard plant turbine replacement	4
Other	12
Total capital expenditures	$ 108

Capital spending in the third quarter of 2009 included expenditures for the Keephills 3 and Clover Bar Energy Centre projects which are described under Subsequent Events. EPCOR Power L.P.'s enhancement project for its Southport and Roxboro plants in North Carolina is nearing completion of the installation phase and the project is expected to be in service by the end of 2009. The enhancements will reduce the plants' environment emission levels and improve their economic performance. EPCOR Power L.P. is also pursuing a project for the repowering of the natural gas turbine at the Oxnard plant which is scheduled to be completed in 2010. The Company's other capital expenditures for the third quarter of 2009 included plant maintenance capital expenditures.

Future cash requirements – excluding EPCOR Power L.P.

Capital Power's estimated cash requirements for the fourth quarter of 2009, excluding EPCOR Power L.P.'s cash requirements, are expected to include approximately $84 million for capital expenditures, approximately $18 million for CPLP distributions to EPCOR, and approximately $7 million for Capital Power's quarterly dividend payable on October 30, 2009. The dividend of $0.315 per share was declared by the Board of Directors on July 17, 2009. The major project expenditures in 2009 are expected to be for the Keephills 3 and Clover Bar Energy Centre construction projects. If total cash requirements for the fourth quarter of 2009 remain as planned, the sources of capital will be cash on hand, cash provided by operating activities, distributions from EPCOR Power L.P. and the use of existing credit facilities. For the longer term, the Company expects to use the same sources of capital as well as new public debt or equity offerings if required. If future distributions from EPCOR Power L.P. decline, it could negatively impact the Company's cash flow.

Future cash requirements – EPCOR Power L.P.

EPCOR Power L.P.'s estimated cash requirements for the fourth quarter of 2009 are expected to include approximately $33 million for capital expenditures on the Roxboro and Southport projects and approximately $40 million for distributions. If its total cash requirements for the fourth quarter of 2009 remain as planned, the sources of capital will be cash on hand, cash provided by operating activities, the net proceeds of the preferred share offering of EPEL, which is discussed under Subsequent Events, and the use of existing credit facilities. If required, other sources of capital for 2009 or subsequent years could include additional public or private debt borrowings or additional public equity market offerings.

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

Contractual Obligations

Capital Power's contractual obligations at September 30, 2009 were as follows:

	Payments Due by Period					
(unaudited, $ millions)	Fourth quarter 2009	2010	2011	2012	2013 and thereafter	Total
Acquired PPA obligations[1]	$ 31	$ 90	$ 89	$ 101	$ 1,249	$ 1,560
Capital projects[2]	120	290	20	-	-	430
Energy purchase and transportation contracts[3] [4]	56	113	93	78	269	609
Operating and maintenance contracts[5]	7	28	28	28	155	246
Operating leases	-	2	1	4	74	81
Forward foreign exchange contracts and commodity contracts-for-differences	38	69	42	5	3	157
Long-term debt	1	247	376	104	1,051	1,779
Interest on long-term debt[6]	28	95	84	67	511	785
Asset retirement obligations[7]	2	8	9	9	349	377
Loan commitments	6	-	-	-	-	6
Total	$ 289	$ 942	$ 742	$ 396	$ 3,661	$ 6,030

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

(2) Capital Power's obligations for capital projects including Keephills 3 and Clover Bar Energy Centre construction and EPCOR Power L.P.'s Roxboro, Southport, North Island and Oxnard facility enhancements. The obligations for Keephills 3 and Clover Bar Energy Centre include the revisions approved in October 2009 as discussed under Subsequent Events.

(3) The natural gas purchase contracts have fixed and variable components. The variable components are based on estimates subject to variability in plant production. These contracts have expiry terms ranging from 2010 to 2016 with built-in escalators in the contracts' terms for pricing.

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

(5) Operating and maintenance contracts are based on fixed fees subject to annual escalators and have expiry terms ranging from 2017 to 2018.

(6) Repayments of bankers' acceptances outstanding under CPLP's and EPCOR Power L.P.'s extendible credit facilities at September 30, 2009, are reflected in the year of the maturity of the respective credit facility.

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

Off-balance Sheet Arrangements

As at September 30, 2009, the Company had no off-balance sheet arrangements which were required to be disclosed in accordance with applicable securities regulations.

Related Party Transactions

EPCOR, including its subsidiaries is the only related party with which the Company had material transactions in the third quarter of 2009. The Company's acquisition of power generation assets from EPCOR in July 2009 was recorded at cost for the non-controlling interests' approximate 72.2% share of the transaction and at fair value for

Capital Power's approximate 27.8% interest in the transaction. The acquisition is described under Significant Events. As part of the Reorganization, the Company issued 56.625 million special voting shares and one special limited voting share to EPCOR for $57 million. In the second quarter, the Company issued one special limited voting share to EPCOR for one dollar. The special limited voting share entitles EPCOR to 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. Also, as part of the Reorganization, the Company borrowed $918 million of long-term debt, including $22 million of fair value increments, of which $39 million was repaid in the third quarter of 2009 as discussed under Liquidity and Capital Resources, and $3 million of the fair value increment was amortized. The terms and interest rates of this debt mirror the debt payable by EPCOR or provide for sufficient payments to EPCOR to allow it to meet its debt obligations to The City of Edmonton. The interest incurred on the Company's long-term debt payable to EPCOR was $15 million for the third quarter of 2009, of which $9 million was capitalized as property, plant and equipment for construction work in progress and the remainder was included in net financing expense.

The Company entered into various agreements with EPCOR to provide for certain aspects of the separation of the business of Capital Power from EPCOR, to provide for the continuity of operations and services and to govern the ongoing relationships between the two entities and their subsidiaries. These transactions are in the normal course of operations and are recorded at the exchange values which are based on normal commercial rates.

The Company's revenues for power sold to EPCOR for resale to its customers were $99 million in the third quarter of 2009. The Company's purchases of distribution and transmission services from EPCOR were $6 million. The Company also contributed $7 million to EPCOR for the construction of aerial and underground transmission lines.

At September 30, 2009, the balances resulting from transactions with EPCOR were as follows:

(unaudited, $ millions)	Sept 30, 2009
Balance sheet	
Accounts receivable	$ 60
Other assets	7
Property, plant and equipment	9
Accounts payable – accrued interest on debt	12
Long-term debt (including current portion)	876
Share capital	-

Outlook

As discussed in the management's discussion and analysis of financial condition and results of operations included in the Prospectus, commencing in 2006, management's strategy has been to sell its Battle River PPA and a portion of its interest in the Sundance PPA and replace this power output with power produced from its own new physical facilities. Interests in the PPAs were sold over the period from 2006 to 2009 with the remaining 15% interest in the Battle River PPA expected to be sold in January 2010. These disposals precede the addition of the new facilities as Clover Bar Unit 1 commenced operations in 2008, followed by Unit 2 in the third quarter of 2009. Clover Bar Unit 3 is expected to be commissioned in 2010 followed by Keephills 3 in 2011. Accordingly, the Company's operating margin and cash flow from operations are expected to be negatively impacted by the Company's reduced interests in PPAs in 2009 and 2010 and are expected to increase as the new facilities come on line in 2010 and 2011.

Alberta forward power prices are expected to remain low in the fourth quarter of 2009 mainly due to low natural gas prices. Consistent with the third quarter results, lower power prices are expected to reduce operating margin (excluding unrealized fair value adjustments), and cash flow from operations for the fourth quarter of 2009 as approximately half of the Company's Alberta commercial portfolio is exposed to the spot market. The remainder has been sold forward at an average price in the low-$60/MWh range. The Alberta commercial plants represent approximately 40% to 50% of operating margin excluding unrealized fair value changes and the non-controlling interest in EPCOR Power L.P.

For 2010, a significant portion of the Alberta commercial portfolio position has been sold forward at an average price in the mid-$60/MWh range which should reduce the exposure to changes in power prices. For 2011, the Alberta commercial portfolio's open position is expected to increase to approximately 60% of the total portfolio which could introduce more variability in operating margin, excluding unrealized fair value adjustments, and cash flow depending on changes in power prices. The average contracted price is in the low-$70/MWh range for the generation sold forward in 2011. The Company will continue to monitor commodity price forecast movements and undertake transactions to optimize the portfolio and limit exposure to price movements.

The sensitivity to an increase/decrease of $1/MWh in the Alberta power price, assuming all other factors are held constant, is estimated to be an operating margin (excluding unrealized fair value adjustments) increase/decrease of $0.5 million for each of the remainder of 2009 and all of 2010. In 2011, the sensitivity of operating margin (excluding unrealized fair value adjustments) to a $1/MWh increase/decrease in the Alberta power price, is expected to increase to approximately $4 million due to the open position on the Keephills 3 facility and the expiration of certain Alberta wholesale and commercial and industrial customer contracts. The Alberta power price sensitivity provides a range of outcomes assuming all other factors are held constant and current risk management strategies, including hedges, are in place. Under normal circumstances, such other factors will not be held constant. In addition, the sensitivity is presented at September 30, 2009 and the degree of sensitivity will change as the Company's mix of assets and operations subject to this factor changes or the degree of commodity hedge coverage changes.

As discussed under Subsequent Events, the Company's share of the total construction cost of the Keephills 3 facility is expected be approximately $955 and commercial operation of the plant is anticipated to commence in the second quarter of 2011. Construction of the third unit of the Clover Bar Energy Centre is expected to continue in the fourth quarter and once complete, the total cost of all three units is expected to be approximately $278 million. The third unit is expected to commence operation in the first quarter of 2010. Progress on the Quality Wind project, in British Columbia, including environmental assessment work, has been delayed as BC Hydro has not yet made its selection of projects under its 2008 Clean Power Call. In 2008, the power generation business of EPCOR submitted a bid in response to the 2008 Clean Power Call proposing a 142 MW wind farm located near Tumbler Ridge, British Columbia. An announcement of BC Hydro's selection was expected at the end of the second quarter but is now not expected until the end of 2009.

For the remainder of 2009, the committed capital expenditures, primarily for Keephills 3 and the Clover Bar Energy Centre and excluding EPCOR Power L.P.'s capital expenditures, are approximately $84 million, and approximately $273 million is committed for 2010. In addition to capital project costs, maintenance capital spending for any given year, excluding EPCOR Power L.P., is expected to be in the range of $30 million to $40 million with an additional $10 million to $20 million in other capital expenditures.

The major items that are expected to reduce operating margin (excluding unrealized fair value adjustments), and cash flow from operations for 2010 compared with 2009 are:

- the impact of the Company's reduced interest in the Battle River PPA after the sale of the remaining portion in January 2010;
- maintenance outages scheduled in 2010 at the Genesee site for Units 2 and 3 compared with only one scheduled outage in 2009. In general, major maintenance expenses for the Genesee maintenance programs can vary significantly depending on the frequency of scheduled turnarounds. The total operating expenses for the two outages in 2010 for both units is expected to be between $18 million and $22 million.

These decreases are expected to be partly offset by higher operating margin (excluding fair value adjustments) from a full year of operation of the second unit of Clover Bar Energy Centre which was commissioned in 2009, and from Unit 3 after commissioning in early 2010.

Business Risks

Our 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.

Risk management is carried out at three levels. Firstly, general oversight, policy review and recommendation, and reviews of risk compliance are provided by the executive team including the Senior Vice President, Strategy and Risk. Secondly, the Director, Risk Management is responsible for monitoring compliance with risk management policies. His responsibilities include oversight of the enterprise risk management program and leadership of our commodity risk management (or middle office) function. Thirdly, the operations and shared service departments are responsible for carrying out the risk management and mitigation activities associated with the risks in their respective operations. The Company management views risk management as an ongoing process and continually looks for ways to enhance the Company's risk management processes.

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

Environmental Regulatory Risk

Many of the Company'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, greenhouse gases (GHG) and other air emissions, water usage, wastewater discharges, hazardous material handling, storage, treatment and disposal of waste and other materials and remediation of sites and land-use responsibility. These regulations can impose liability for costs to investigate and remediate contamination without regard to fault and under certain circumstances, liability may be joint and several resulting in one contributing party being held responsible for the entire obligation.

On April 29, 2009, the Canadian Environment Minister announced in a media interview that the Canadian Federal Government is planning new climate change regulations aimed at coal-fired power in Canada's electricity sector. The regulations would purportedly require all newly constructed coal generation plants to use technology to capture GHG and inject it underground for permanent storage. Compliance with this and other known and unknown environmental regulations may require material capital and operating expenditures and failure to comply with such regulations could result in fines, penalties or the forced curtailment of operations.

Further, there can be no assurances that compliance with and/or changes to environmental regulations will not materially adversely impact the Company's business, prospects, financial conditions, operations or cash flow.

The Company's business is a significant emitter of nitrogen oxide (NOx), sulphur dioxide (SO_2) and mercury and is required to comply with all licenses and permits and existing and emerging federal, provincial and state requirements, including programs to reduce or offset GHG emissions.

EPCOR Power L.P.'s wood waste plants may also be subject to SO_2 and mercury reduction requirements within the next five to seven years. There are a number of uncertainties associated with the estimated cost of compliance with these existing and emerging requirements. Compliance with new regulatory requirements may require EPCOR Power L.P. to incur significant capital expenditures and/or additional operating expenses.

Electricity Price and Volume Risk

The Company's revenues are tied, directly and indirectly, to the market price for electricity in the jurisdictions in which the Company operates. The Company 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 sources of electricity; the cost of complying with applicable regulatory requirements, including environmental; the structure of the particular market; and weather conditions. It is not possible to predict future electricity prices with complete certainty, and electricity price volatility could therefore have a material adverse effect on the Company.

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

When aggregate customer electricity consumption (load shape) changes unexpectedly, the Company 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. The Company purchases blocks of electricity in advance of consumption so as to minimize exposure to extreme price fluctuations, especially during higher priced peak hour periods. In order to do this, the Company relies on historical aggregate consumption data (load shape) provided by load settlement agents and local distribution companies to anticipate what aggregate customer 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, the Company is exposed to prevailing market prices because it must either buy the electricity if it is short or sell the electricity if it is long. Such exposures can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.

Fuel Cost, Supply and Transportation

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

The Company's fuel expense for the Genesee plants is predominantly comprised of coal supply. Coal is supplied under long-term agreements with the Genesee Coal Mine joint venture, of which the Company holds a 50% interest. 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. To the extent that coal mine operations or equipment suffers significant disruption, existing coal stock-pile inventories representing an approximate 6 months supply would be exhausted prior to, the generation of electricity from the Genesee generation units and the associated revenues being negatively impacted.

The Roxboro and Southport facilities purchase coal and coal-based fuel from local suppliers in the Southeast U.S. The coal and coal-based fuel is transported to the power plants by rail service. Any disruption in rail service due to unforeseen circumstances could impair the operations of these coal-fired power plants if alternative transportation cannot be arranged in a timely manner. Existing coal supply contracts will meet the 2009 requirements and approximately half of the 2010 requirements for Roxboro and Southport. There can be no assurance of if, when or upon what terms, including pricing, the existing supply agreements will be renewed or replaced.

Some of the Company's natural gas-fired plant operations are susceptible to the risks associated with the volatility of natural gas prices beyond any fixed price term. Natural gas purchases for the Naval Station, Naval Training Centre, North Island, Oxnard and Kenilworth power plants are made under variable price structures with fuel cost flow-through provisions that partially mitigate risks relating to natural gas price changes. However, each of these power plants has PPAs extending for terms in excess of existing contractual supply arrangements. The

Company is exposed to commodity price risk on its natural gas purchases for EPCOR Power L.P.'s Tunis Plant beginning in 2010 when its natural gas supply agreements end prior to expiry of the OEFC PPA in 2014. In addition, EPCOR Power L.P.'s Greeley facility is exposed to fuel price risk when existing natural gas contracts expire in 2011, prior to the PPA expiry in 2013. The failure to contract for additional fuel supply for these plants at the end of existing contract terms at acceptable prices may lead to a disruption in operations and an inability to perform under their power and steam purchase agreements. The Company also maintains a quantity of natural gas in storage for trading and management of natural gas needs. At September 30, 2009, the estimated fair value of the inventory was $6 million. The inventory is subject to resale in current or forward markets and realized or unrealized gains or losses on such natural gas are subject to the volatility of the market price for natural gas.

Wood waste is required to fuel EPCOR Power L.P.'s two Canadian biomass wood waste plants, Williams Lake and Calstock. In addition, the enhancements that are in process at the North Carolina plants will increase the level of wood waste consumption at those plants. At Williams Lake, the cost of delivered wood waste for the firm energy component (approximately 80% of fuel supply cost) is flowed through to BC Hydro, while EPCOR Power L.P. is at risk for the wood waste price escalation for the remaining 20% of the fuel supply. At Calstock, the PPA price does not permit EPCOR Power L.P. to directly flow through the fuel supply cost to the OEFC, and EPCOR Power L.P. is at risk for wood waste price escalation. Market forces, including levels of activity in the regional forestry sector, competition from other users of wood waste and limits to the distance over which wood waste can economically be transported, expose EPCOR Power L.P. to price and supply risk for wood waste.

EPCOR Power L.P.'s five Ontario plants (namely, Nipigon, Kapuskasing, North Bay, Calstock and Tunis) also generate electricity in part from the use of waste heat gases of adjoining natural gas compressor stations. Supply of the waste heat gases is secured under long-term contracts; however the availability of the waste heat gases varies depending on the output of the compressor stations along the TransCanada pipeline system, and the host's altering those operations under the terms of a Waste Heat Optimization Agreement. In addition, the availability of waste heat gases is also dependent on the compressor stations remaining in use and their ability to supply the waste heat gases. Declining waste heat availability that began in 2007 continued into 2008 and 2009 due to lower throughput on the TransCanada pipeline system. The Company expects there will be a potential for recovery of volumes beginning in 2012.

Performance of hydroelectric facilities is dependent upon the availability of water. Variances in water flows, which may be caused by shifts in weather or climate patterns, the timing and rate of melting and other uncontrollable weather-related factors affecting precipitation, could result in volatility of hydroelectric plant revenues. In addition, the hydroelectric facilities are exposed to potential dam failure, which could affect water flows and have a material adverse impact on revenues from the associated plants. There is an increasing level of regulation respecting the use, treatment and discharge of water, and respecting the licensing of water rights, in Alberta. A continued tightening of such regulations could have a material adverse effect on the Company's business, financial condition and results of operation.

The Company's wind power facilities, like those of the Kingsbridge I project, have no fuel costs but are dependent on the availability and constancy of sufficient wind resources to meet generation capacity. Wind resources can vary due to abnormal weather conditions, and decreases in wind speed or duration can negatively impact the performance of the wind turbines and, in turn, could potentially have a material negative impact on related revenues.

Operational Risk

The operation of power plants involves many risks, including: (i) the breakdown or failure of, and the necessity to repair, upgrade or replace, power and steam generation equipment, transmission lines, pipelines or other equipment, structures or processes; (ii) the inability to secure critical or back-up parts for generator equipment on a timely basis; (iii) fire, explosion or other property damage; (iv) an inability to obtain adequate fuel supplies, site control, and operation and maintenance and other site services for at least the term of any PPA; (v) performance of generation equipment below expected levels, including those pertaining to efficiency and availability; (vi) fluctuating costs, including fuel costs; (vii) compliance with all operating permits and licences (including environmental permits and emissions restrictions) under applicable laws and regulations; and (viii) an inability to retain, at all times, adequate skilled personnel, the occurrence of any of which could have a material adverse effect on the Company, including a shut-down of a power plant or reduction in its operating capacity, emissions in excess of permitted levels, or diversion of water levels below levels required by regulation.

The inability of the Company's power plants to generate the expected amount of electricity that will be sold under contract or to the applicable market would have a significant adverse impact on the revenues of the Company. If a power plant delivers less than the required quantities of electricity in a given month, or is available for production less than required under the PPAs in a given month, revenue may be insufficient to cover contractual or financial obligations.

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, the Company's cost of generating electricity will be increased and/or the Company's revenues may be negatively affected. As an adopter of new technology, the Company can be exposed to design flaws or other issues, the impacts of which may not be covered by warranties or insurance. The decision regarding expenditures and maintenance would depend on, among other things, the remaining term of the PPA. The failure of the Company's facilities to operate at required capacity levels may result in the facilities having their contracted capacity reduced and, in certain cases, the Company having to make payments on account of reduced capacity to power purchasers.

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

In the case of EPCOR Power L.P.'s Ontario plants, a combination of increasing operation and maintenance costs, fuel costs, and decreasing availability of waste heat as a fuel source, may cause EPCOR Power L.P. to restrict their operation to on-peak hours to maximize revenue under their respective PPAs.

In addition, counterparties to PPAs have remedies available to them if the Company fails to operate facilities in accordance with contract requirements, including the recovery of damages and termination of contractual arrangements.

Projects in Construction and Development

The Company participates in the design, construction and operation of new power generation facilities. Development of power generation facilities is subject to substantial risks and can be adversely affected by changes in engineering and design requirements, non-performance or errors by third-party contractors, construction performance falling below expected levels, changes in government policy and regulation, environmental concerns, increases in capital costs, increases in interest rates, competition in the industry and other matters beyond the direct control of the Company. Any one of these factors could cause actual results to vary significantly and the Company may not be able to recover its investment, materially and adversely affecting the Company's financial position, operating results and business.

The Company attempts to mitigate these risks by performing detailed project analysis and due diligence prior to and during construction or acquisition, and by entering into favourable long-term contracts for output and services to be provided where and when available.

Credit Risk

Credit risk is the possible financial loss associated with the potential inability of counterparties to satisfy their contractual obligations to the Company, including payment and performance. In the event of default by a purchasing counterparty, existing PPAs and steam purchase agreements may not be replaceable on similar terms, particularly those agreements that have favourable pricing for the Company relative to their current markets. The Company is also dependant upon counterparties with respect to its cogeneration hosts and suppliers of fuel to its plants. Failure of any such counterparties could impact the operations of some of the Company's plants and could adversely impact the Company's financial results.In the wholesale electricity market, should a counterparty default, the Company may not be able to effectively replace such counterparty in order to manage short or long electricity positions, resulting in reduced revenues or increased power costs.. Furthermore, a prolonged deterioration in economic conditions, such as the recent economic recession, could increase the foregoing risks and could have a material adverse affect on the Company.

Financial Liquidity Risk

The Company's future development, enhancement opportunities, acquisition plans or other cash requirements, may require additional financing from time to time. The ability of the Company to arrange such financing in the future will depend in part upon prevailing market conditions as well as the business performance of the Company. Current global financial conditions and recent market events have been characterized by increased volatility and the resulting tightening of the credit and capital markets has reduced the amount of available liquidity and overall economic activity. There can be no assurance that debt or equity financing, the ability to borrow funds or cash generated by operations will be available or sufficient to replace financing as it matures or becomes due, or to meet or satisfy the Company's initiatives, objectives or requirements or, if financing is available to the Company, that it will be on terms acceptable to the Company. See Liquidity and Capital Resources. The inability of the Company to access sufficient amounts of capital on terms acceptable to the Company for its operations could have a material adverse effect on the Company's business, prospects and financial condition.

Supply Risk of Alberta PPAs

The Company holds interests in PPAs in Alberta which entitle the Company to its proportionate interest in the electricity produced from certain generating units up to their committed capacity. In most cases where plant capability falls below committed capacity, the Company is entitled to receive availability payments from the plant owner based on 30-day rolling average power pool prices and target availability. The occurrence of an event which disrupts the ability of the power plants to produce or sell power or thermal energy for an extended period under such PPAs, including events which preclude the subsequent purchasers of the rights and obligations under the acquired PPAs from fulfilling their obligations under such PPAs, could have a material negative impact on the ability of the Company to generate revenue. In such circumstances, the Company may be required to replace the electricity that was not delivered to it 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 PPA, thus increasing the cost of energy purchases to the Company.

PPA Contract Risk

Many of the Company's generation plants operate under PPAs. Such contracts contain performance benchmarks that must be achieved and other obligations that must be complied with by the Company. The Company may incur charges in the event of unplanned outages or variations from the contract performance benchmarks. In addition, there is no assurance that counterparties to PPAs will perform their obligations or make required payments to the Company or EPCOR Power L.P., as applicable.

Electricity sales associated with the Company's Genesee 1 and 2 facilities are governed by the terms of a PPA. These 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. Most of the Company's other plants, including Brown Lake, Miller Creek, and Kingsbridge I, operate under long-term commercial contracts with counterparties. Electricity sales or steam sales associated with Joffre are subject to market price variability as there are provisions in the NOVA contract that require the facility to run to provide steam to the host facility, irrespective of market prices.

In order to stabilize future cash flows, EPCOR Power L.P. seeks to re-contract existing generation plants under new or extended contracts and acquire new plants that meet its investment criteria. However, there is no guarantee that existing PPAs will be extended or renewed on more favourable terms. Electricity prices under the PPAs for the Naval Facilities and Oxnard are based on the purchasing utilities' SRAC. The SRAC formula is determined by the California Public Utility Commission and is subject to adjustment. In the future, the California Public Utility Commission may make adjustments to the SRAC formula to change the basis on which future electricity prices will be determined for these facilities. Such adjustments may adversely affect the value of the affected PPAs to the Company.

Reliance on Transmission Systems

The Company depends on transmission facilities owned and operated by third parties to deliver the wholesale power it sells from its power generation plants to its customers. If transmission is disrupted, or if the transmission capacity infrastructure is inadequate, the Company's ability to sell and deliver wholesale power may be adversely impacted. If a region's power transmission infrastructure is inadequate, the Company's recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The Company also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets. The Company's ability to develop new projects is also impacted by the availability of various transmission and distribution systems.

Foreign Exchange Risk

Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar affect the Company's capital and operating costs, revenues and cash flows and could have an adverse impact on the Company's financial performance and condition. The U.S. plant operations of EPCOR Power L.P. and the foreign-sourced equipment required for capital projects such as Keephills 3 and Clover Bar are transacted in U.S. dollars. In addition, certain of EPCOR Power L.P.'s indebtedness is denominated in U.S. dollars.

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

PPA Contract Expiration Risks

Power generated from the Company's facilities is, in many cases, sold under PPAs that expire at various times. When a PPA expires, there can be no assurance that a subsequent PPA will be available or, if available, that any such subsequent PPA will be on terms, or at prices, acceptable to the Company. Failure by the Company to enter into a subsequent PPA on terms and at prices that permit the operation of a facility on a profitable basis could have a material adverse effect on the Company's operations and financial condition, and may even require the Company to temporarily or permanently cease operations at the affected facility.

Derivatives Risk

The Company 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 the Company to other risks. When the Company 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 the Company to post significant amounts of cash collateral or other credit support to its counterparties. In addition, the Company purchases and sells commodity-based contracts in the natural gas and electricity markets for trading purposes. In the future, the Company 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. See Financial Instruments — Risk Management and Hedge Accounting for more information about the Company's use of derivative instruments.

Weather Risks

Weather can have a significant impact on the Company's operations. Temperature levels, seasonality and precipitation, both within the Company'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. In addition, the performance of the hydroelectric facilities is partly dependent upon the availability of water and variances in water flows are caused by non-controllable weather-related factors affecting precipitation and could result in volatility of hydroelectric plant revenues. Although the Company's wind power facilities have no fuel costs, they rely on the availability and constancy of wind resources, which could vary due to abnormal weather conditions.

Financial exposures associated with extreme weather are partially mitigated through our insurance programs.

Litigation Update

On June 11, 2009, William Pidruchney filed a Statement of Claim against The City of Edmonton, the Mayor and Councillors of The City of Edmonton, EPCOR, EPCOR Power L.P.'s General Partner, EPCOR Power L.P. and Capital Power (the Co-defendants). Mr. Pidruchney alleged, among other things, that The City of Edmonton acted beyond its power and contrary to the Municipal Government Act (Alberta) and did not observe an appropriate public process in connection with the initial public offering involving Capital Power. Based on its review of the available information, Capital Power believes that the claim is without merit and intends to vigorously defend itself. On June 26, 2009, Capital Power filed a Statement of Defence denying all of the allegations contained in the Statement of Claim. On July 3, 2009, the Alberta Court of Queen's Bench denied an application by William Pidruchney for an interim injunction to delay the closing of the Capital Power initial public offering and its acquisition of EPCOR's power generation business. The court was not satisfied that there was any real merit to Mr. Pidruchney's application. The Co-defendants have now applied to the Alberta Court of Queen's Bench for summary dismissal of Mr. Pidruchney's action against them.

On June 30, 2009, an Originating Notice was filed in the Court of the Queen's Bench of Alberta, Judicial District of Edmonton, by the Alberta Federation of Labour, the Canadian Union of Public Employees, Local 30, and the Civic Service Union 52. The Notice named The City of Edmonton, EPCOR Utilities Inc. and Capital Power Corporation as Respondents and requested that the transaction pursuant to which the power generation assets previously owned by EPCOR were transferred to Capital Power be overturned on the basis that certain purported actions taken by The City of Edmonton in connection with the initial public offering were allegedly outside the jurisdiction of the municipality under the Municipal Government Act. On September 25, 2009, the Alberta Court of Queen's Bench denied the application.

Future Accounting Changes

International Financial Reporting Standards

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

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

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

International Financial Reporting Standard
IFRS 7, IAS 32, IAS 39 Financial Instruments
IAS 23 Borrowing Costs
IAS 18 Revenue
IAS 16 Property, Plant and Equipment
IAS 31 Interests in Joint Ventures
IAS 21 The Effects of Changes in Foreign Exchange Rates
IFRS 3 Business Combinations
IAS 12 Income Taxes
IAS 17 Leases
IAS 37 Provisions, Contingent Liabilities and Contingent Assets
IAS 36 Impairment of Assets

The information obtained from the diagnostic phase was used to develop a detailed plan for convergence and implementation. The convergence and implementation work has the following five key sections.

Financial Statement Adjustments

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

As the project progresses, the timing of completion of certain items may change as changes to standards and other external factors such as discussions with certain stakeholders may result in a change in priorities. However, the Company believes the project has sufficient resources to meet the overall project timeline.

Financial Statements

There are also a number of international standards which relate to financial statement presentation. Draft financial statements highlighting the disclosure and presentation requirements were prepared for EPCOR before the Reorganization and will be used as a foundation for preparing draft financial statements in accordance with IFRS for Capital Power. Draft financial statements will be brought forward to the Audit Committee by then end of the first quarter of 2010. The development of the financial statement presentation will evolve throughout the project as impacts of implementing the various standards are quantified.

Systems Updates

The diagnostic phase of the project identified two key accounting system requirements. The system must be able to capture 2010 financial information under both the prevailing Canadian GAAP and IFRS to allow comparative reporting in 2011, the first year of reporting under IFRS. It must also be able to accommodate possible changes to foreign currency translation methods, depending on how certain foreign entities are classified under IFRS. EPCOR developed a systems strategy in 2008 and implementation of a parallel fixed asset subledger and general ledger was completed in the third quarter of 2009.

Policies and Internal Controls

In the determination of the financial statement adjustments, requirements for changes to Company policies and internal controls will be identified and documented. As there may be factors other than IFRS impacting policies and internal controls, the formal documentation and approval of revised policies and internal controls will not occur until the third quarter of 2010.

The impact of IFRS on certain agreements, such as debt, shareholder and compensation agreements, has also been included in the plan. Assessments of these agreements will be performed in the fourth quarter of 2009 and the first quarter of 2010 as most of these agreements were revised as a result of the Reorganization.

Training

The Company recognizes that training at all levels is essential to a successful conversion and integration. Accounting staff have attended two training sessions with more planned to occur throughout the conversion process. The Audit Committee will receive regular updates on the conversion project and training for the Board of Directors and Audit Committee will occur throughout the project.

Disclosures about financial instruments

In June 2009, the CICA amended Handbook Section 3862 Financial Instruments – Disclosures, to adopt the amendments recently made by the International Accounting Standards Board to IFRS 7 Financial Instruments: Disclosures. The amendments require enhanced disclosures about fair value measurements, including the relative reliability of the inputs used in those measurements, and about the liquidity risk of financial instruments. The Company will assess the impacts of these amendments on its financial statements and implement the necessary additional disclosures commencing with the annual financial statements for 2009.

Consolidated financial statements and non-controlling interests

In January 2009, the CICA issued Handbook Section 1601 – Consolidated Financial Statements and Section 1602 – Non-controlling Interests, which replace Section 1600 – Consolidated Financial Statements. Section 1601 establishes the standards for the preparation of consolidated financial statements while Section 1602 establishes the standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 is equivalent to the corresponding provisions of International Accounting Standard 27 – Consolidated and Separate Financial Statements.

Sections 1601 and 1602 will apply to Capital Power's interim and annual consolidated financial statements relating to periods commencing on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year provided Section 1582 – Business Combinations is also adopted at the same time. The impact of the new standards and the option to adopt them early will be assessed as part of the Company's IFRS project.

Business combinations

In January 2009, the CICA issued Handbook Section 1582 – Business Combinations, which replaces Section 1581 – Business Combinations and provides the Canadian equivalent to IFRS 3 – Business Combinations. The section will apply on a prospective basis to a business combination by Capital Power for which the acquisition date is on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year provided Sections 1601 – Consolidated Financial Statements and 1602 – Non-controlling Interests are also adopted at the same time. The impact of the new standard and the option to adopt it early will be assessed as part of the Company's IFRS project.

Significant Accounting Policies

Revenue recognition under PPAs

The Company's Genesee power generation units 1 and 2 operate under a PPA. Under the terms of the PPA, the target levels of generation availability set out in the PPA recognize that the generation units will experience planned and forced outages over the terms of the PPA. The Company records the electricity revenue from the generation units under PPAs at the price embedded in the PPAs, including expected incentives and penalties for operating above or below specified availability targets set out in the PPA. Under this approach, incentives for the period may be deferred and included in non-current liabilities on the balance sheet if they are not expected to be sustained over the full term of the PPA. As penalties are incurred, any balance of deferred incentive is drawn down. If cumulative penalties exceed cumulative incentives, the excess is charged to income and no deferred charge is created.

The degree to which incentives are recognized or deferred changes from period to period due to revisions to the long-term outlook of plant performance, which is based on historical performance, planned maintenance, reliability and generation availability, and due to revisions in the estimated long-term price embedded in the PPA.

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

Leases or arrangements containing a lease

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

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

Foreign currency translation

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

Consolidation of EPCOR Power L.P. and CPLP

While the Company owns only 30.6% of the outstanding units of EPCOR Power L.P. and an approximate 27.8% interest in CPLP, it controls both partnerships under GAAP. Accordingly, EPCOR Power L.P. and CPLP are consolidated in the financial statements of the Company.

Critical accounting estimates

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the items for which significant estimates were made in the financial statements.

Fair values

The Company is required to estimate the fair value of certain assets and obligations for determining the valuation of certain financial instruments, asset impairments, asset retirement obligations and purchase price allocations for business combinations, and for determining certain disclosures.

Fair values of financial instruments are based on quoted market prices when these instruments are traded in active markets. In illiquid or inactive markets, the Company uses appropriate price modeling to estimate fair value. For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. Goodwill arising on business combinations is tested for impairment annually or more frequently if events and circumstances indicate that a possible impairment may exist. To test for impairment, the fair value of the reporting unit to which the goodwill relates is compared with the carrying value, including goodwill, of the reporting unit. If the carrying value of the reporting unit exceeds its fair value, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the impairment loss, if any.

The Company reviews the valuation of long-lived assets subject to amortization when events or changes in circumstances may indicate or cause a long-lived asset's carrying amount to exceed the total undiscounted future cash flows expected from the asset's use and eventual disposition. An impairment loss, if any, would be recorded as the excess of the carrying amount of the asset over its fair value, measured by either market value, if available, or estimated by calculating the present value of expected future cash flows related to the asset. Fair values and useful lives are used in determining potential impairments for each long-lived asset, which will vary with each asset and market conditions at the particular time.

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

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

Useful lives of assets

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

Income taxes

The Company follows the asset and liability method of accounting for income taxes. Current income taxes are recognized for the estimated income taxes payable or recoverable for the period. Estimates of future income taxes resulting from temporary differences between the carrying values of assets and liabilities in the financial statements and their tax values are recognized as future income tax assets and liabilities. Future income tax assets are assessed to determine the likelihood that they will be recovered from future taxable income. To the extent recovery is not considered likely, a valuation allowance is recorded and charged against income in the period that the allowance is created or revised. Estimates of the provision for current income taxes, future income tax assets and liabilities and any related valuation allowance might vary from actual amounts incurred. Income taxes will vary with taxable income and, under certain conditions, with fair values of assets and liabilities.

PPA availability incentives

Electricity revenue from the Genesee 1 and 2 units includes an estimate of availability incentives as described above under Significant Accounting Policies. Availability incentive payments received are deferred in non-current liabilities and recognized in energy sales when they are expected to be sustained over the full term of the PPA. Accordingly the amount deferred can vary from no amount to the full amount of availability incentive payments received.

Financial Instruments

The Company has various financial instruments that are classified for financial reporting purposes as “available for sale”, “held for trading”, “held to maturity”, or “loans and receivables”. Financial liabilities are classified as either “held for trading” or “other liabilities”. Initially, all financial assets and financial liabilities are recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

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

The classification, carrying amounts and fair values of other financial instruments held at September 30, 2009 are as follows:

	Carrying amount		Fair value
(unaudited, $ millions)	Loans and receivables	Other financial liabilities	
Other assets	$ 77	$ -	$ 72
Long-term debt (including current portion)	$ -	$ 1,771	$ 1,745

Risk management and hedging activities

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

(unaudited, $ millions)	Energy cash flow hedges	Energy non-hedges	Foreign exchange non-hedges	Total
Total derivative instruments net assets (liabilities) as at September 30, 2009	$ (19)	$ 69	$ 17	$ 67

Energy derivatives designated as accounting hedges

At September 30, 2009, the net fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of $19 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. The net derivative liability is primarily due to a decrease in the forward Alberta natural gas prices relative to the derivative contract prices. Unrealized gains and losses for fair value changes on derivatives that qualify for hedge accounting are recorded in other comprehensive income and reclassified to net income as energy revenues, energy purchases, or fuel as appropriate when realized.

On July 31, 2009, EPCOR Power L.P. applied hedge accounting to certain of its natural gas purchase contracts. An unrealized gain of $4 million for the increase in the fair value of these contracts for the period from the inception of the hedge to September 30, 2009 was recognized in other comprehensive income. Prior to the application of the hedge, the unrealized changes in the fair value of these contracts were recognized in net income.

Energy derivatives not designated as accounting hedges

At September 30, 2009, the net fair value of energy derivative instruments not designated as hedges for accounting was a net asset of $69 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. This net derivative asset was primarily due to unrealized gains arising from a net short position for the portfolio combined with lower forward Alberta electricity prices, relative to the derivative contract prices.

At September 30, 2009, the fair value of the Company's forward foreign currency contracts was a net derivative instrument asset of $17 million. The net asset was due to the impact of a strengthening Canadian dollar relative to the U.S. dollar on forward foreign exchange sales contracts used to hedge U.S. dollar denominated revenues. The weighted average fixed exchange rate for contracts outstanding at September, 2009 was $1.12 for every U.S. dollar. Unrealized and realized gains and losses on foreign exchange derivatives that are not designated as hedges for accounting purposes are recorded in energy revenues or foreign exchange gains and losses.

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

Risk management and hedge accounting

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

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

Other comprehensive income

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

For the period ended September 30, 2009, an unrealized gain, net of income taxes, of $8 million was recorded in other comprehensive income for the effective portion of cash flow hedges, and a realized loss, net of income taxes, of $21 million was reclassified to energy purchases and revenues as appropriate. There was no ineffective portion of cash flow hedges for which unrealized gains or losses were required to be recognized in income. Of the $29 million in net fair value gains related to derivative instruments designated as cash flow hedges included in accumulated other comprehensive income at September 30, 2009, net losses of $14 million, net of taxes of $1 million are expected to settle and be reclassified to net income over the next twelve months.

Internal Control Over Financial Reporting

As part of the Reorganization and acquisition of the power generation assets and operations from EPCOR in July 2009, the Company assumed the underlying processes and internal controls. The agreements between the Company and EPCOR for transitional and ongoing services between the two entities and their subsidiaries also provide for continuity of internal controls after the Reorganization and acquisition. There was no change in the Company's internal control over financial reporting during the period beginning July 1, 2009 and ended on September 30, 2009 that has materially affected, or is reasonably likely to materially affect the Company's internal control over financial reporting.

Forward-looking Information

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

Forward-looking information in this MD&A includes, among other things, information relating to: (i) expected timing of commercial operation and project cost of Keephills 3 and Clover Bar Energy Centre Unit 3; (ii) future financings by EPCOR Power Equity Ltd; (iii) expectations for the use of the Company's committed bank credit facilities; (iv) Capital Power's and EPCOR Power L.P.'s cash requirements for the fourth quarter of 2009 and related financing; (v) expectations regarding future financial strength and access to and terms of future financings; (vi) the expected impact of the further reduction in the Company's interest in the Battle River PPA and of Keephills 3 coming on line, on cash flow from operations and operating margin; (vii) expectations for Alberta spot power prices in the fourth quarter of 2009 and their impact on operating margin and cash flow from operations; (viii) expectation that the Alberta commercial portfolio position in 2010 will reduce the exposure to changes in power prices; (ix) expectation that the Alberta commercial portfolio's open position will increase to approximately 60% of the total portfolio in 2011; (x) the Company's estimated sensitivity to Alberta power prices; (xi) the expected annual spending for maintenance capital and other capital for the Company excluding EPCOR Power L.P.; (xii) expectation that the two maintenance outages scheduled in 2010 at the Genesee site will reduce operating margin (excluding unrealized fair value adjustments) and cash flow from operations, and the expected amount of operating expense for the two outages; and (xiii) expectation that the operating margin in 2010 will benefit from a full year of operation of the second unit of Clover Bar Energy Centre and from Unit 3 after its commissioning.

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

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

This MD&A includes the following updates to previously disclosed forward-looking statements: (i) the estimated date for Clover Bar Energy Centre Unit 3 to enter commercial operation was revised from the third quarter of 2010 to the first quarter of 2010; (ii) the estimated total cost for all three units at Clover Bar Energy Centre was revised from $284 million to $278 million; (iii) the estimated total project cost for Keephills 3 was revised from $1.8 billion to $1.9 billion and Capital Power's share was revised from $903 million to $955 million; (iv) the estimated commercial operation date for Keephills 3 was revised from the first quarter of 2011 to the second quarter of 2011; and (v) the expected timing of BC Hydro's selection of projects under its 2008 Clean Power Call was revised from the second quarter of 2009 to the end of 2009 and the completion of the environmental assessment work for the Quality Wind project, which was previously expected in the third quarter of 2009, has been delayed.

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

Quarterly 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 (unaudited)	Sept 30, 2009	June 30, 2009
Share price		
High	$22.39	$23.00
Low	$19.50	$22.00
Close	$19.75	$22.35
Volume traded (millions)	12.1	5.8

On October 30, 2009, the Company had 21.75 million common shares outstanding which were publicly held and represented approximately 27.8% of CPLP. On October 30, 2009, EPCOR held 56.625 million exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis), representing approximately 72.2% of CPLP. The weighted average number of shares outstanding for the three months ended September 30, 2009 was 78.375 million. On October 30, 2009, the Company had 56.625 million special voting shares outstanding and one special limited voting share outstanding, which were held by EPCOR.

Additional Information

Additional information relating to Capital Power Corporation, including continuous disclosure documents, is available on SEDAR at www.sedar.com.

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2009
Revenues	$ 525
Energy purchases and fuel	307
	218
Operations, maintenance and direct administration	49
Indirect administration	27
Depreciation, amortization and asset retirement accretion (note 5)	44
Foreign exchange losses	3
Net financing expenses (note 17)	17
	140
Income before income tax reductions and non-controlling interests	78
Income tax reductions (note 18)	(2)
Income before non-controlling interests	80
Non-controlling interests (note 13)	66
Net income	$ 14
Earnings per share (note 14)	
Basic	$ 0.64
Diluted	0.59
Weighted average number of common shares outstanding	
Basic	21,750,000
Diluted	78,375,000

See accompanying notes to consolidated financial statements.

CAPITAL POWER CORPORATION

Consolidated Balance Sheet
(Unaudited, in millions of dollars)

September 30, 2009

		2009
Assets		
Current assets:		
Cash and cash equivalents (note 24)	$	64
Accounts receivable		248
Income taxes recoverable		20
Inventories (note 4)		57
Prepaid expenses		13
Derivative instruments assets (note 20)		148
Future income tax assets (note 18)		2
		552
Property, plant and equipment (note 5)		3,199
Power purchase arrangements (note 6)		536
Contract and customer rights and other intangible assets (note 7)		181
Derivative instruments assets (note 20)		138
Future income tax assets (note 18)		40
Goodwill (note 8)		119
Other assets (note 9)		117
Assets held for sale (note 30)		36
	$	4,918

	2009
Liabilities and Shareholders' Equity	
Current liabilities:	
Accounts payable and accrued liabilities	$ 275
Derivative instruments liabilities (note 20)	124
Other current liabilities	9
Future income tax liabilities (note 18)	17
Current portion of long-term debt (note 10)	247
	672
Long-term debt (note 10)	1,524
Derivative instruments liabilities (note 20)	95
Other non-current liabilities (note 11)	99
Future income tax liabilities (note 18)	59
	2,449
Non-controlling interests (note 13)	1,975
Shareholders' equity:	
Share capital (note 14)	477
Retained earnings	14
Accumulated other comprehensive income (note 15)	3
	494
Contingencies and commitments (note 27)	
Subsequent events (note 31)	
	$ 4,918

See accompanying notes to consolidated financial statements.

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2009
Share capital:	
Common shares issued (notes 3 and 14)	$ 477
Balance, end of period (note 14)	477
Retained earnings:	
Net income	14
Balance, end of period	14
Accumulated other comprehensive income:	
Other comprehensive income	3
Balance, end of period (note 15)	3
Total shareholders' equity, end of period	$ 494

See accompanying notes to consolidated financial statements.

CAPITAL POWER CORPORATION

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

		Three months ended September 30, 2009
Net income	$	14
Other comprehensive income (loss), net of income taxes:		
Unrealized gains on derivative instruments designated as cash flow hedges[1]		8
Reclassification of losses on derivative instruments designated as cash flow hedges to net income[2]		21
Unrealized loss in self-sustaining foreign operations[3]		(33)
Non-controlling interests[3] (note 13)		7
		3
Comprehensive income	$	17

1 For the three months ended September 30, 2009, net of income tax expense of $1.

2 For the three months ended September 30, 2009, net of reclassification of income tax recovery of $2.

3 For the three months ended September 30, 2009, net of income tax expense of nil.

See accompanying notes to consolidated financial statements.

CAPITAL POWER CORPORATION

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

	Three months ended September 30, 2009
Operating activities:	
Net income	$ 14
Adjustments to reconcile net income to cash flows from operating activities:	
Depreciation, amortization and asset retirement accretion (note 5)	44
Non-controlling interests in EPLP and CPLP (note 13)	64
Fair value changes on derivative instruments	(28)
Unrealized foreign exchange losses	3
Future income taxes	(3)
Other	(1)
	93
Change in non-cash operating working capital (note 16)	(40)
	53
Investing activities:	
Property, plant and equipment and other assets	(108)
Business acquisition, net of acquired cash (note 3)	(1,293)
	(1,401)
Financing activities:	
Proceeds from issue of long-term debt	1,001
Repayment of long-term debt	(41)
Issue of common shares (notes 3 and 14)	500
Share issue costs (notes 3 and 14)	(32)
Debt issue costs	(13)
	1,415
Foreign exchange losses on cash held in a foreign currency	(3)
Increase in cash and cash equivalents	64
Cash and cash equivalents, beginning of period	-
Cash and cash equivalents, end of period	$ 64
Supplementary cash flow information:	
Interest paid net of interest received	$ 18
Income taxes recovered net of income taxes paid	(1)

See accompanying notes to consolidated financial statements.

1. Description of business:

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

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

2. Summary of significant accounting policies:

(a) Basis of presentation:

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

These unaudited interim consolidated financial statements include the accounts of Capital Power, its subsidiaries, and its proportionate share of assets, liabilities, revenues and expenses of joint ventures. They also include the accounts of the Company’s approximate 30.6% interest in EPCOR Power L.P. (EPLP) and the Company’s approximate 27.8% interest in Capital Power LP (CPLP). Under GAAP, Capital Power controls EPLP and CPLP which therefore are subsidiaries of Capital Power.

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

The Company has determined that December 31 will be its fiscal year-end. As the Company was incorporated on May 1, 2009, there is no comparative balance sheet as at December 31, 2008 or comparative statement of income, statement of changes in shareholders’ equity, statement of comprehensive income and statement of cash flows for the period ended September 30, 2008.

Although the Company was incorporated on May 1, 2009 the Company did not have any results from operations or significant cash flows in the period from May 1 to June 30, 2009. Accordingly, the company’s statements of income, comprehensive income and cash flows reflect only information for the three months ended September 30, 2009.

(b) Changes in significant accounting policies:

Future accounting changes

The CICA has announced that Canadian reporting issuers will need to begin reporting under International Financial Reporting Standards (IFRS), including comparative figures, by the first quarter of 2011. The Company is currently working on its IFRS conversion project which includes assessing the impact of the differences in accounting standards on the Company’s future financial reporting requirements.

In June 2009, the CICA amended Handbook Section 3862 Financial Instruments – Disclosures, to adopt the amendments recently made by the International Accounting Standards Board to IFRS 7 Financial Instruments: Disclosures. The amendments require enhanced disclosures about fair value measurements, including the relative reliability of the inputs used in those measurements, and about the liquidity risk of financial instruments. Although the amendments apply to financial statements relating to fiscal years ending after September 30, 2009, comparative information is not required in the first year of application. We are assessing the impacts of these amendments on our financial statements and will implement the necessary additional disclosures commencing with the annual financial statements for 2009.

2. Summary of significant accounting policies, continued:

(b) Changes in significant accounting policies, continued:

In January 2009, the CICA issued Handbook Section 1601 – Consolidated Financial Statements and Section 1602 - Non-controlling Interests, which replace Section 1600 – Consolidated Financial Statements. Section 1601 establishes the standards for the preparation of consolidated financial statements while Section 1602 establishes the standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. Section 1602 is equivalent to the corresponding provisions of IFRS IAS 27 – Consolidated and Separate Financial Statements.

Sections 1601 and 1602 will apply to interim and annual consolidated financial statements relating to periods commencing on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year, provided Section 1582 – Business Combinations is also adopted at the same time. The impact of the new standards and the option to adopt them early is being assessed as part of the Company's IFRS conversion project.

In January 2009, the CICA issued Handbook Section 1582 – Business Combinations, which replaces Section 1581 – Business Combinations and provides the Canadian equivalent to IFRS 3 – Business Combinations. The section will apply, on a prospective basis, to future business combinations for which the acquisition date is on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year provided Sections 1601 – Consolidated Financial Statements and 1602 – Non-controlling Interests are also adopted at the same time. The impact of the new standard and the option to adopt it early is being assessed as part of the Company's IFRS conversion project.

(c) Measurement uncertainty:

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

The degree to which revenues are recognized or deferred under the Power Purchase Arrangements (PPAs) described in note 2(k) depends upon long-term outlooks of generation unit performance. Such outlooks of performance are estimated based on the generation units' historical performance, planned maintenance, reliability and generation availability, and revisions in the estimated long-term price embedded in the PPA.

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

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

Measurement of certain of the Company's pension costs and plan assets and obligations requires the use of estimates with respect to expected plan investment performance, salary escalation, retirement ages of employees, timing of related future cash flows and appropriate discount rates for use in discounted cash flow and actuarial techniques.

2. Summary of significant accounting policies, continued:

(c) Measurement uncertainty, continued:

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

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

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

Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

(d) Revenue recognition:

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

The Company recognizes revenue from its Alberta generation units operating under PPAs as described in note 2(k). PPAs are a form of long-term sales arrangements between the owner of a generation unit and the buyer of the PPA.

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

(e) Financial instruments:

Financial assets are identified and classified as either available for sale, held for trading, held to maturity, or loans and receivables. Financial liabilities are classified as either held for trading or other liabilities. Initially, all financial assets and financial liabilities are recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

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

2. Summary of significant accounting policies, continued:

(e) Financial instruments, continued:

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

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

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

(f) Derivative instruments and hedging activities:

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

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

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

2. Summary of significant accounting policies, continued:

(f) Derivative instruments and hedging activities, continued:

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

The Company may use forward interest rate or swap agreements and option agreements to manage the impact of fluctuating interest rates on existing debt.

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

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

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

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

2. Summary of significant accounting policies, continued:

(f) 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 as described above. 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 price quotations by reference to bid or asking price as appropriate, in active markets. In illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

(g) Income taxes:

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

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

(h) Cash and cash equivalents:

Cash and cash equivalents include cash or highly liquid, investment-grade short-term investments and are recorded at fair market value.

(i) Inventories:

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

2. Summary of significant accounting policies, continued:

(j) Property, plant and equipment:

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

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

The Company capitalizes interest during construction to provide for the costs of borrowing on construction activities. Interest is applied during construction using the weighted average cost of debt incurred on the Company's external borrowings used to finance qualifying assets.

(k) Power purchase arrangements:

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

Under the terms of the Alberta PPAs, the Company is obligated to make fixed and variable payments to the owners of the underlying generation units over their respective terms. Such amounts are recorded as operating expenses as incurred. At September 30, 2009, the remaining term of the 20-year Sundance PPA is approximately 11 years. The Company is also obligated to make fixed and variable payments to the buyer of the Battle River PPA, in proportion to its effective ownership interest, until the sale of the Company’s remaining interest in the Battle River Power Syndicate Agreement (Battle River PSA) is completed in 2010 as described in note 30.

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

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

The EPLP PPAs reflect the cost to acquire long-term sales contracts under which revenue is earned by EPLP’s generation units. The EPLP PPAs are amortized over their remaining terms, which range from one to 18 years.

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

Contract rights include acquired management and operations agreements and water rights. Costs assigned to contract rights related to management and operations agreements are amortized on a straight-line basis, from the dates of acquisition, over the remaining contract terms which range from 5 to 57 years. Water rights associated with acquired hydroelectric power generation plants are recorded at cost and are amortized over the remaining useful lives of the associated property, plant and equipment.

Other rights include the cost of land lease agreements for use in wind power projects in Ontario and coal supply access rights relating to the Keephills 3 Project (note 27(b)). The lease rights are amortized on a straight-line basis over the estimated useful lives of the related wind power assets, commencing when those assets are constructed and commissioned for service. The access rights will be amortized over the life of the coal supply agreement and amortization will commence when the Keephills 3 plant is commissioned for service.

2. Summary of significant accounting policies, continued:

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

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

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

(m) Goodwill:

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

(n) Other assets:

Loans and other long-term receivables are comprised of promissory notes receivable and amounts due from customers more than one year from the balance sheet date and will be repaid between 2009 and 2025.

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

(o) Impairment of long-lived assets:

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

(p) Deferred availability incentives:

Under the terms of the Genesee PPA, the target levels of generation availability set out in the PPA recognize that the respective generation units will experience planned and forced outages over the term of the PPA. The Company records the electricity revenue from these generation units at the price embedded in the PPA, including expected incentives and penalties for operating above or below specified availability targets set out in the PPA. Under this approach, incentives for the current period are deferred since they are not expected to be sustained over the full term of the PPA. As penalties are incurred, any balance of deferred incentive will be drawn down. If cumulative penalties exceed cumulative incentives, the excess will be charged to income and no deferred charge will be created. Deferred incentive amounts are included in other non-current liabilities on the balance sheet.

The degree to which incentives are recognized or deferred will change due to revisions to the long-term outlook of plant performance, which is based on historical performance, planned maintenance, reliability and generation availability, and due to revisions in the estimated long-term price embedded in the PPA.

2. Summary of significant accounting policies, continued:

(q) Asset retirement obligations:

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

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

(r) Leases or arrangements containing a lease:

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

(s) Contract liabilities:

The Company's contract liabilities, primarily related to acquired EPLP PPAs, are being amortized over the terms of the contracts which range from three to eight years.

(t) Foreign currency translation:

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

Foreign currency transactions and financial statements of integrated foreign operations are translated to Canadian dollars using the temporal method. Transactions denominated in foreign currencies are translated at exchange rates in effect at the transaction date. Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect on the balance sheet date. The resulting foreign exchange gains and losses are included in the consolidated statements of income.

2. Summary of significant accounting policies, continued:

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

The Company maintains additional defined contribution and defined benefit pension plans to provide pension benefits to those employees (comprising less than 30% of total employees of Capital Power) who are not otherwise served by LAPP.

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

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

(v) Stock-based compensation

The Company determines the fair value of stock options using a binomial option pricing model at the date of grant. The fair value of the granted options is recognized over the vesting period as a compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, as the Company accounts for actual forfeitures as they occur.

2. Summary of significant accounting policies, continued:

(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. This method computes the number of additional shares by assuming all outstanding options, for which the average market price of the common shares for the period exceeds the exercise price, are exercised. The total number of shares is then reduced by the number of common shares assumed to be repurchased from the total issuance proceeds, using the average market price of the Company's common shares for the period. The average market price of the Company's common shares for the period ended September 30, 2009 was below the exercise price of all granted options and as a result none of the share purchase options described in note 14 have a dilutive effect on earnings per share. Exchangeable common limited partnership units of CPLP, as described in note 3, are exchangeable for common shares of the Company and have a dilutive effect on earnings per share as described in note 14.

(x) Offsetting of financial assets and financial liabilities:

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

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

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

3. Acquisition of assets and initial public offering:

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

- Formation of CPLP: Capital Power and a wholly-owned subsidiary of Capital Power (Capital Power LP Holdings Inc.) formed CPLP. Capital Power acquired one general partner unit (GP Unit) and became the initial general partner of CPLP. Capital Power LP Holdings Inc. acquired one common limited partnership unit and as a result, became the initial limited partner in CPLP.
- Sale of EMCC Limited to Capital Power: EPCOR transferred all of the outstanding common shares of EMCC Limited to Capital Power in return for payment of approximately $468 million in cash.
- Contribution of Assets by EMCC Limited to CPLP: EMCC Limited contributed substantially all of its assets (consisting primarily of certain securities of subsidiary entities, its class B shares in the capital of EPLP Investments Inc. and promissory note of EPLP Investments Inc.) to CPLP in return for GP Units. Capital Power transferred its GP Unit in CPLP to EMCC Limited and as a result EMCC Limited became the general partner of CPLP.

3. Acquisition of assets and initial public offering, continued:

- Sale of Assets by EPCOR Power Development Corporation (EPDC) to CPLP: EPDC transferred substantially all of its assets (consisting primarily of assets related to Genesee Units 1 and 2, the Genesee Coal Mine joint venture and certain interests in partnerships) to CPLP in return for 56.625 million exchangeable limited partnership units of CPLP and approximately $896 million in cash. CPLP financed the cash payment with the proceeds from a long-term debt obligation to EPCOR.

  Concurrently, EPDC subscribed for 56.625 million special voting shares of Capital Power for a nominal amount.

Immediately following completion of the Reorganization, Capital Power held approximately 27.8% of CPLP while EPCOR held 56.625 million exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) representing approximately 72.2% of CPLP. Each exchangeable limited partnership unit is accompanied by a special voting share in the capital of Capital Power which entitles the holder to a vote at Capital Power shareholder meetings, subject to the restriction that such special voting shares must at all times represent not more than 49% of the votes attached to all Capital Power common shares and special voting shares, taken together. Capital Power and EPCOR have agreed that for so long as EPCOR holds not less than a 20% interest in the common shares of Capital Power, the number of directors will not be less than nine. The special voting shares also entitle EPCOR, voting separately as a class, to nominate and elect a maximum of four directors of Capital Power. There are currently twelve directors on Capital Power's board of directors. Accordingly, Capital Power will have control over CPLP and, on that basis, the operations of CPLP will be consolidated by Capital Power for financial statement purposes.

Immediately following completion of the Reorganization, CPLP held 49% and EPCOR held 51% of the voting rights in EPLP Investments Inc. EPLP Investments Inc. owns the approximate 30.6% interest in EPLP previously owned by EPCOR. However, CPLP is entitled to all of the economic interest in EPLP Investments Inc. Accordingly, effective July 1, 2009 Capital Power will consolidate the financial results of EPLP.

(Unaudited, tabular amounts in millions of dollars)

3. Acquisition of assets and initial public offering, continued:

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

Cash and cash equivalents	$ 71
Other current assets	437
Property, plant and equipment	3,163
Power purchase arrangements	572
Contract and customer rights and other intangible assets	179
Derivative instruments assets – non-current	74
Future income tax assets – non-current	57
Acquired goodwill	123
Other non-current assets	122
Assets held for sale	36
Current liabilities	(414)
Long-term debt (including current portion)	(1,761)
Derivative instruments liabilities – non-current	(64)
Future income tax liabilities – non-current	(93)
Other non-current liabilities	(99)
	2,403
Non-controlling interests in net assets (note 13)	(1,935)
Fair value of net assets acquired	$ 468

The values of the assets and liabilities above reflect management's best estimates as of the release date of these financial statements. The values of certain assets and liabilities are preliminary, and are subject to refinement as additional information is obtained. As of the issue date of these financial statements, the Company is performing additional analysis on its income tax balances recognized on acquisition and upon finalization, material adjustments may result.

The $179 million of contract and customer rights and other intangibles includes $115 million of contract rights, $43 million of coal supply access rights and $21 million of other rights which include customer rights, lease rights, software intangibles and emission credits. Substantially all of the acquired contract and customer rights and other intangible assets are subject to amortization as described in note 2(l).

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

Non-controlling interests in net assets acquired include preferred share and other non-controlling interests in EPLP at the acquisition date of $122 million and $370 million respectively, as well as limited partnership units of CPLP issued to non-controlling interests as a part of the Reorganization of $1,302 million. The remaining non-controlling interests of $141 million relate to the non-controlling interest in net assets acquired.

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

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

(Unaudited, tabular amounts in millions of dollars)

4. Inventories:

	September 30, 2009
Small parts and other consumables	$ 41
Coal	10
Natural gas held in storage for trading purposes	6
	$ 57

Inventories expensed upon usage during the three months ended September 30, 2009 of $4 million were charged to energy purchases and fuel, and operations, maintenance and administration. No write-downs of inventories or reversals of previous write-downs were recognized in the three months ended September 30, 2009. At September 30, 2009, no inventories were pledged as security for liabilities.

5. Property, plant and equipment:

	September 30, 2009			
	Composite Depreciation Rate	Cost	Accumulated Depreciation	Net Book Value
Land	None	$ 66	$ -	$ 66
Plant and equipment	5.4%	2,323	27	2,296
Contributions	12.0%	(27)	(1)	(26)
Construction work in progress	None	863	-	863
		$ 3,225	$ 26	$ 3,199

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

	Three months ended September 30, 2009
Depreciation on assets in service	$ 33
Amortization of PPAs	12
Gain on settlement of asset retirement obligations (note 12)	(2)
Accretion on asset retirement obligations (note 12)	1
Amortization of contributions	(1)
Amortization of contract and customer rights and other intangible assets	1
	$ 44

Interest capitalized to property, plant and equipment for the three months ended September 30, 2009 is $9 million.

6. Power purchase arrangements:

	September 30, 2009		
	Cost	Accumulated amortization	Net book value
Alberta PPAs	$ 149	$ 3	$ 146
EPLP PPAs	399	9	390
	$ 548	$ 12	$ 536

(Unaudited, tabular amounts in millions of dollars)

7. Contract and customer rights and other intangible assets:

	September 30, 2009		
	Cost	Accumulated amortization	Net book value
Contract rights	$ 114	$ 1	$ 113
Other rights	50	-	50
Software intangibles	7	-	7
Emission credits	7	-	7
Customer rights	4	-	4
	$ 182	$ 1	$ 181

8. Goodwill:

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

	Three months ended September 30, 2009
Acquired goodwill (note 3)	$ 123
Foreign exchange translation adjustment	(4)
Balance, end of period	$ 119

9. Other assets:

	September 30, 2009
Carrying amount	
Loans and other long-term receivables	$ 49
Net investment in lease	28
Investment in PERH	13
Portfolio investments	7
Other	20
	$ 117

Net investment in lease

The PPA under which the Company's power generation facility located in Oxnard, California operates is considered to be a direct financing lease for accounting. The PPA expires in 2020. The current portion of the net investment in lease of $2 million is included in accounts receivable. Financing income for the three months ended September 30, 2009 of $1 million is included in revenues.

Investment in PERH

Through the acquisition described in note 3, the Company, as part of its EPLP subsidiary, acquired 17.0% of the common share interests and 14.2% of the preferred interests in Primary Energy Recycling Holdings LLC (PERH). Effective August 24, 2009, PERH converted its outstanding preferred interests into common shares. As a result of the conversion, the Company now holds 14.3% of the outstanding common shares of PERH. Until the conversion date, the Company's common share interest in PERH was accounted for using the equity method and the preferred interest was recorded on the cost basis. Subsequent to the conversion of the preferred interests into common shares, the Company commenced recording its entire 14.3% common share interest on the cost basis. For the period from July 1 to August 24, 2009, equity losses of $1 million, included in operations, maintenance and administration expense, have been recorded against the common share investment in PERH.

(Unaudited, tabular amounts in millions of dollars)

9. Other assets, continued:

Investment in PERH, continued

The Company, through its EPLP subsidiary, monitors its investment in PERH for impairment by considering current economic factors and records an impairment charge when it believes the investment has experienced a decline that is other than temporary. The Company estimates the fair value of its investment in PERH by considering factors such as the quoted market price of the securities issued by PERC, which owns the remaining interests in PERH not held by EPLP. During the three months ended September 30, 2009 the Company has not recognized an impairment on this investment.

10. Long-term debt:

	Effective Interest Rate	September 30, 2009
Unsecured senior debt payable to EPCOR		
Due in 2010 at 6.95%	4.90%	$ 203
Due in 2011 at 6.60%	5.53%	204
Due in 2016 at 6.75%	6.16%	134
Due in 2018 at 5.80%	5.63%	165
Due in 2018 at 9.00%	7.41%	170
		876
EPLP unsecured senior notes (US$190), at 5.90%, due in 2014	6.23%	203
EPLP unsecured senior medium-term notes, at 5.95%, due in 2036	7.11%	203
EPLP unsecured senior medium-term notes (US$150), at 5.87%, due in 2017	6.13%	159
EPLP unsecured senior medium-term notes (US$75), at 5.97%, due in 2019	6.26%	78
EPLP secured term loan, at 11.25%, due in 2010	10.69%	1
Non-recourse financing:		
Brown Lake Project, at 8.7%, due in 2016	7.13%	6
Joffre Cogeneration Project, at fixed and floating rates, due in 2020	8.35%	42
CPLP revolving extendible credit facilities, at floating rates, due in 2009	3.15%	77
EPLP revolving extendible credit facilities, at floating rates, due in 2009	1.16%	142
		1,787
Less: Current portion		247
Deferred debt issue costs		16
		$ 1,524

10. Long-term debt, continued:

Unsecured senior debt payable to EPCOR

The unsecured senior debt payable to EPCOR matures between 2010 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.

EPLP unsecured senior notes

The unsecured senior notes of $203 million mature in 2014 and are fully and unconditionally guaranteed by EPLP as to payment of principal, premium, if any, and interest on a senior unsecured basis. Interest is payable semi-annually.

The unsecured senior medium-term notes of $203 million are due in 2036 with interest payable semi-annually.

The unsecured senior medium-term notes aggregating to $237 million (US$225 million) were issued in two tranches. The $159 million (US$150 million) and $78 million (US$75 million) are due in 2017 and 2019 respectively with interest payable semi-annually.

EPLP secured term loan

The term loan matures in 2010 and is secured by a first fixed and specific mortgage over the Queen Charlotte plant which has a carrying amount of $14 million.

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 $100 million. Brown Lake Project financing is secured by a charge against project assets which have a carrying amount of $10 million.

EPLP and CPLP revolving extendible credit facilities

Unsecured three-year credit facilities of $100 million, $100 million and $125 million, for a total of $325 million, committed to 2011, and uncommitted amounts of $20 million, are available to the Company's subsidiary, EPLP. At September 30, 2009, the Company had $66 million in bankers' acceptances and $76 million (US$71 million) in U.S. LIBOR loans outstanding under this facility. Unsecured three-year credit facilities of $700 million, committed to 2012 and uncommitted amounts of $20 million, are available to the Company's subsidiary, CPLP. At September 30, 2009, the Company had $77 million in bankers' acceptances outstanding under this facility.

The Company also has unsecured credit facilities of $500 million available through its CPLP subsidiary. These facilities have a maturity date of July 8, 2011 with an option to extend for an additional 364 day period. As at September 30, 2009, no amounts have been drawn on this facility, but letters of credit of $90 million have been issued as described in note 28.

(Unaudited, tabular amounts in millions of dollars)

10. Long-term debt, continued:

EPLP and CPLP revolving extendible credit facilities, continued

Under the terms of the extendible facilities, the Company may obtain advances by way of prime loans, U.S. base rate loans, U.S LIBOR loans and bankers' acceptances. Depending on the facility, amounts drawn by way of prime loans bear interest at the prevailing Canadian prime rate or the average one-month bankers' acceptance rate plus a spread ranging from 0.75% to 1.00%. Amounts drawn by way of U.S. base rate loans bear interest at a bank determined variable commercial lending rate or the prevailing Federal Funds Rate as published by the U.S. Federal Reserve Board plus a spread ranging from 0.75% to 1.00%. Amounts drawn by way of U.S. LIBOR loans bear interest at the prevailing LIBOR rate plus a spread based on the Company's credit rating. Amounts drawn by way of bankers' acceptances bear interest at the prevailing bankers' acceptance rate plus a spread based on the Company's credit rating.

11. Other non-current liabilities:

	September 30, 2009
Asset retirement obligations (note 12)	$ 81
Employee future benefit liabilities	11
Other	7
	$ 99

12. Asset retirement obligations:

	September 30, 2009
Liabilities assumed on acquisition of assets (note 3)	$ 88
Liabilities incurred	2
Liabilities settled	(2)
Asset retirement accretion expense	1
	89
Less: current portion in accounts payable and accrued liabilities	8
	$ 81

The Company estimates the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $383 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2009 and 2090. The majority of the payments to settle the obligations are expected to occur between 2023 and 2064 for the power generation plants, and between 2009 and 2013 for sections of the Genesee coal mine. Discount rates ranging from 4.1% to 8.7% were used to calculate the carrying amount of the asset retirement obligations. No assets have been legally restricted for settlement of these liabilities.

(Unaudited, tabular amounts in millions of dollars)

13. Non-controlling interests:

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

	Three months ended September 30, 2009
Non-controlling interests in EPLP	$ 20
Non-controlling interests in CPLP	44
Preferred share dividends paid by subsidiary company	2
	$ 66

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

	September 30, 2009
Non-controlling interests in EPLP in net assets acquired (note 3)	$ 370
Net income attributable to non-controlling interests	20
Other comprehensive loss attributable to non-controlling interests	(20)
Distributions to non-controlling interests	(17)
Non-controlling interests in EPLP, end of period	353
Non-controlling interests in CPLP in net assets acquired (note 3)	141
Partnership units issued to non-controlling interests (note 3)	1,302
Net income attributable to non-controlling interests	44
Other comprehensive income attributable to non-controlling interests	13
Non-controlling interests in CPLP, end of period	1,500
Preferred shares outstanding in acquired subsidiaries (note 3)	122
Preferred shares issued by subsidiary companies, end of period	122
	$ 1,975

The non-controlling interests in EPLP represent the approximately 69.4% interest in EPLP not owned by CPLP. The non-controlling interests in CPLP represents the approximately 72.2% interest in CPLP not owned by the Company which includes approximately 72.2% of CPLP's approximate 30.6% interest in EPLP.

14. Share capital:

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

(Unaudited, tabular amounts in millions of dollars)

14. Share capital, continued:

Issued and outstanding	September 30, 2009
21,750,000 common shares	$ 477
56,625,000 special voting shares	-
1 special limited voting share	-
	$ 477

The $500 million of common shares issued to the public are recorded net of share issue costs of $32 million as described in note 3. Future income taxes of $9 million related to the share issue costs have been recorded as an increase to common shares.

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.

Share Purchase Options

Under the Company's long term incentive plan, the Company provides stock options to certain employees to purchase common shares, provided that the number of shares reserved for issuance will not exceed 10% of the common shares to be outstanding at closing and that the aggregate number of shares issued by the Corporation under this Plan will not exceed 5,000,000 common shares.

During the three months ended September 30, 2009 the Company granted 993,400 stock options with one third vesting on January 1 of each of 2010, 2011, and 2012. Fair value of these options at grant date was $2.57 per option resulting in total compensation expense recognized of $1 million in operations, maintenance and administration for the three months ended September 30, 2009. Granted options may be exercised within 7 years of the grant date at a price of $23.00 per share.

At September 30, 2009, none of the Company's outstanding stock options were vested.

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

Variable	**Value**
Expected life	Seven-year term
Risk free interest rate	Based on Government of Canada treasury bills and bonds at December 31, 2008
Volatility	20% (estimated based on similar publicly-traded companies)
Dividend yield	4.75% to 5.5%

Earnings per share

The 56.625 million exchangeable limited partnership units issued to EPCOR as described in note 3 may be exchanged for common shares of Capital Power on a one-for-one basis. For purposes of the diluted earnings per share calculation, the exchange of such units for common shares of the Company would remove the non-controlling interest in net income related to CPLP of $44 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 approximately $12 million.

(Unaudited, tabular amounts in millions of dollars)

15. Accumulated other comprehensive income:

The components of accumulated other comprehensive income, at September 30, 2009, are as follows:

	September 30, 2009
Unrealized gains on derivative instruments designated as cash flow hedges[1]	$ 29
Unrealized loss in self-sustaining foreign operations[2]	(33)
Non-controlling interests[2]	7
	$ 3

[1] Net of income tax expense of $3 million.

[2] Net of income tax expense of nil.

16. Change in non-cash working capital:

	Three months ended September 30, 2009
Accounts receivable	$ (39)
Income taxes recoverable	3
Inventories	(4)
Prepaid expenses	(3)
Accounts payable and accrued liabilities	(3)
Other current liabilities	6
	$ (40)

17. Net financing expenses:

	Three months ended September 30, 2009
Interest on long-term debt	$ 26
Capitalized interest	(9)
	$ 17

(Unaudited, tabular amounts in millions of dollars)

18. Income taxes:

	Three months ended September 30, 2009
Current income taxes	$ -
Future income taxes	(2)
	$ (2)

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

	Three months ended September 30, 2009
Income before income taxes and non-controlling interests	$ 78
Statutory income tax rates	29.0%
Income taxes at statutory rate	23
Increase (decrease) resulting from:	
Income not subject to income taxes at statutory rates	(12)
Change in income tax related to out-of-period adjustment	(10)
Unrecognized future income tax assets	(4)
Non-taxable amounts	2
Adjustment for enacted changes in income tax laws and rates and other tax rate differences	(1)
	$ (2)

(Unaudited, tabular amounts in millions of dollars)

18. Income taxes, continued:

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

	September 30, 2009
Property, plant and equipment – differences in net book value and tax bases	$ (114)
Losses carried forward	74
Cumulative eligible capital	21
Deferred income from partnerships	(19)
Asset retirement obligations	15
Power purchase arrangements	(11)
Derivative Instruments	5
Other	(5)
Net future income tax liabilities	$ (34)
Presented on the balance sheet as follows:	
Current assets	$ 2
Non-current assets	40
Current liabilities	(17)
Non-current liabilities	(59)
	$ (34)

At September 30, 2009, the Company has non-capital losses carried forward of approximately $239 million, of which $152 million relate to certain U.S. subsidiaries. These losses expire between 2010 and 2029. The Company also has capital losses for income tax purposes of approximately $12 million which carry forward indefinitely. There are non-capital losses available to be carried forward of $22 million, and capital losses available to be carried forward of $3 million for which no tax benefit has been recognized.

Reorganization

As a result of the Reorganization (as described in note 3), Capital Power holds an economic interest in CPLP of 27.8%. Accordingly, the Company records current and future income tax provisions related to its economic interest in CPLP’s taxable income. The Company also records future income tax provisions related to CPLP’s temporary differences, and related to temporary differences of partnerships of which CPLP is a partner, to the extent of the Company’s economic interest in CPLP.

Out-of-period adjustment

During the quarter ended September 30, 2009, EPLP, a subsidiary of the Company, recorded an out-of-period adjustment of $10 million relating to 2007, 2008 and 2009 to recognize net future income tax assets associated with EPLP’s interest in a long-term investment. The long-term investment is treated as a partnership for U.S. tax purposes and the adjustments are attributable to allocation of tax deductions between the partners that were incorrectly calculated by the long-term investment's external tax advisors for the relevant periods. Of the $10 million, $3 million is attributable to 2007, $6 million is attributable to 2008 and $1 million is attributable to 2009. The Company's management determined that the impact of the adjustment, after considering non-controlling interests, was not material to the expected results for the year ending December 31, 2009. As such, the adjustment was recorded during the quarter ended September 30, 2009.

(Unaudited, tabular amounts in millions of dollars)

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

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

The classification, carrying amount and fair value of the Company's other financial instruments at September 30, 2009 are summarized as follows:

		September 30, 2009	
Financial asset or liability	Classification	Carrying amount	Fair value
Other assets			
Loans and other long-term receivables	Loans and receivables	$ 49	$ 44
Net investment in lease	Loans and receivables	28	28
Long-term debt (including current portion)	Other financial liabilities	1,771	1,745

Net investment in lease

The fair value of the Company's net investment in lease is based on the estimated interest rates implicit in comparable lease arrangements or loans plus an estimated credit spread based on the counterparty risk as at September 30, 2009.

Long-term debt

The fair value of the Company's long-term debt is based on determining a current yield for the Company's debt as at September 30, 2009. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Company's debt. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

Other financial instruments

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

The fair value of certain capital venture investments cannot be measured reliably as the shares are not quoted in an active market. 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.

(Unaudited, tabular amounts in millions of dollars)

20. Derivative instruments and hedge accounting:

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

The derivative instruments assets and liabilities used for risk management purposes as described in note 21 consist of the following:

	September 30, 2009			
	Energy		Foreign exchange	
	Cash flow hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:				
Current	$ 17	$ 128	$ 3	$ 148
Non-current	25	93	20	138
Derivative instruments liabilities:				
Current	(32)	(91)	(1)	(124)
Non-current	(29)	(61)	(5)	(95)
Net fair value	$ (19)	$ 69	$ 17	$ 67
Net notional buys (sells):				
Megawatt hours of electricity (millions)	(2)	(3)		
Gigajoules of natural gas (millions)	47	11		
Foreign currency (U.S. dollars)			$ (431)	
Range of contract terms in years	0.1 to 7.3	0.1 to 5.0	0.1 to 6.2	

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices as appropriate, in active markets. When there are limited observable prices due to illiquid or inactive markets, 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 using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rate as the discount rate for time value, and volatility when 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.

(Unaudited, tabular amounts in millions of dollars)

20. Derivative instruments and hedge accounting, continued:

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. With respect to natural gas, the Company has determined the market is active to the end of the contract terms. The fair value of the natural gas supply contracts is determined by reference to published price quotations.

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

	Three months ended September 30, 2009	
	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ 31	$ (22)
Energy non-hedges	(4)	-
Foreign exchange non-hedges	32	-

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

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

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity and natural gas prices. For the three months ended September 30, 2009, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized in the income statement was nil. Net losses of $14 million, net of income taxes of $1 million, related to derivative instruments designated as cash-flow hedges, are expected to settle and be reclassified to net income over the next twelve months. The Company's cash flow hedges extend up to 2016.

21. 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 including the Senior Vice President, Strategy and Risk.

Capital Power's Senior Vice President, Strategy and Risk reports regularly to the Board of Directors on risk management activities of the executive team. 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 minimize volatility in earnings and cash flow.

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

Market risk

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

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

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

21. Risk management, continued:

Market risk, continued

Commodity price risk

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

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

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

The fair value of the Company's energy related derivatives at September 30, 2009 that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 20.

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 VaR uses a statistical confidence interval of 95% over a twenty business day holding period. This measure reflects a 5% probability that, over the twenty 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.

21. 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 95% confidence level, does not reflect the extent of potential losses beyond that percentile. Losses on the other 5% 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 5% of the time. As VaR is not a perfect measure of risk, the Company applies a safety factor to the calculated VaR amount to estimate total exposure (TE) which attempts to capture unaccounted for exposures due to the assumptions and limitations inherent in the calculation of VaR and to improve the confidence level beyond 95%.

The estimation of TE takes into account positions from all wholly-owned subsidiaries and subsidiaries in which the Company has controlling interest, and reflects the Company's aggregate commodity positions from its trading and asset portfolios. Capital Power's Board of Directors has established an aggregate TE limit, under their risk management policy, which 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.

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 attempt to minimize 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.

21. Risk management, continued:

Market risk, continued

Foreign exchange risk, continued

The Company primarily uses foreign currency forward contracts to fix the functional currency of its non-functional currency cash flows thereby reducing its anticipated U.S. dollar denominated transactional exposure. The Company looks to limit foreign currency exposures as a percentage of estimated future cash flows. The percentage amount to be fixed will generally be higher, the shorter the period into the future that the cash flows relate to. At September 30, 2009, US$453 million or approximately 94% of expected future net cash flows from EPLP's U.S. plants had been economically hedged for 2009 to 2015 at a weighted average exchange rate of $1.12 per U.S. dollar. At September 30, 2009, the Company has transactional exposure for US$22 million or approximately 91% of expected future net cash flows for capital expenditure commitments, which have been economically hedged for 2009 to 2011 at a weighted average exchange rate of $1.09 per U.S. dollar.

As at September 30, 2009, 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 by approximately $1 million after tax. There would be no impact to other comprehensive income.

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

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating rate short-term and long-term loans and obligations. The Company is exposed to interest rate risk from the possibility that changes in the interest rates will affect future cash flows or the fair values of its financial instruments. In some circumstances, floating rate funding may be used for short-term borrowings and other liquidity requirements. At September 30, 2009, the proportion of fixed rate debt was approximately 88% of total long-term debt outstanding. The Company may also use derivative instruments to manage interest rate risk. At September 30, 2009, the Company did not hold any interest rate derivative instruments.

Assuming that the amount and mix of fixed and floating rate loans and net debt remains unchanged from that held at September 30, 2009, a 100 basis point change to interest rates would decrease or increase full year net income by $1 million and would have no direct impact on other comprehensive income.

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

(Unaudited, tabular amounts in millions of dollars)

21. Risk management, continued:

Market risk, continued

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 and counterparty risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into a transaction with the counterparty. Exposures and concentrations are subsequently monitored and are regularly reported to the executive team. Creditworthiness continues to be evaluated after transactions have been initiated, at minimum, on an annual basis. To manage and mitigate credit risk, the Company employs various credit mitigation practices such as master netting agreements, margining to reduce energy trading risks, credit derivatives and other forms of credit enhancements including cash deposits, parent company guarantees, and bank letters of credit.

Maximum credit risk exposure

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

	September 30, 2009
Cash and cash equivalents	$ 64
Accounts receivable [1]	248
Derivative instruments assets [1]	286
Loans and other long-term receivables	49
Net investments in leases	28
Loan commitments to third parties	6
	$ 681

[1] The Company's maximum exposures related to accounts receivable and derivative instruments assets by major credit concentration are comprised of maximum exposures of $170 million for generation and $364 million for wholesale.

This table does not take into account collateral held. At September 30, 2009, the Company held cash deposits of $2 million as security for certain counterparty accounts receivable and derivative contracts. The Company is not permitted to sell or re-pledge this collateral in the absence of default of the counterparties providing the collateral. At September 30, 2009, the Company also held other forms of credit enhancement in the form of letters of credit of $25 million and parental guarantees of $723 million.

21. Risk management, continued:

Credit risk, continued

Credit quality and concentrations

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

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

	September 30, 2009	
	Investment grade [1] or secured [3]	Non-investment grade [1]
Accounts receivable and financial derivative instruments		
Generation	100%	-
Wholesale [2]	90%	10%
Cash and cash equivalents	100%	-
Loans and other long-term receivables	100%	-

[1] Credit ratings are based on the Company's internal criteria and analyses which take into account, among other factors, the investment grade ratings of external credit rating agencies when available.

[2] Includes industrial end-use customers, trading and position management counterparties.

[3] Certain accounts receivable and other financial assets are considered to have low credit risk as they are either secured by the underlying assets, secured by other forms of credit enhancements, or the counterparties are local or provincial governments.

Generation credit risk

Credit risk exposure from power purchase arrangements, agreements with independent system operators, power and steam sales contracts, and certain energy supply agreements is predominantly restricted to accounts 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 power purchase arrangements and steam purchase agreements may not be recovered since the contracts may not be replaceable on similar terms under current market conditions. Consequently, the Company's financial performance depends on the continued performance by customers and suppliers of their obligations under these long-term agreements. Credit risk exposure is mitigated by dealing with creditworthy counterparties, netting amounts by legally enforceable set-off rights, and, when appropriate, taking back security from the counterparty. Credit risk with government-owned or sponsored entities and regulated public utility distributors is generally considered low.

(Unaudited, tabular amounts in millions of dollars)

21. Risk management, continued:

Credit risk, continued

Wholesale and merchant credit risk

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

Accounts receivable and allowance for doubtful accounts

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

The aging of accounts receivable was:

	September 30, 2009		
	Gross accounts receivable	Allowance for doubtful accounts	Net accounts receivable
Current[1]	$ 249	$ 1	$ 248
Outstanding 30 to 60 days	1	1	-
Total	$ 250	$ 2	$ 248

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

In conjunction with the acquisition of assets described in note 3, the Company has assumed allowances for doubtful accounts of $2 million, which is the balance included in accounts receivable as at September 30, 2009. The Company has also assumed allowances for doubtful accounts of $2 million relating to long-term receivables which are recorded against the long-term receivable balance in other assets at September 30, 2009.

At September 30, 2009, the Company held $2 million of customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers.

At September 30, 2009, there was no provision for credit losses associated with accounts receivable from treasury, trading and energy procurement counterparties as all balances are considered to be fully collectable.

(Unaudited, tabular amounts in millions of dollars)

21. Risk management, continued:

Liquidity risk

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

CPLP has a long-term debt rating of BBB, assigned by both Standard and Poor's (S&P) and DBRS Limited (DBRS). EPLP has a long-term debt rating of BBB+ and BBB(high), assigned by S&P and DBRS respectively.

As at September 30, 2009, the Company had undrawn and committed bank credit facilities, including operating lines of credit, of $1,282 million, of which $723 million is committed for at least two years. In addition, EPLP has a Canadian shelf prospectus under which it may raise up to $1 billion in partnership units or debt securities, of which a maximum of $600 million can be medium-term notes. The Canadian shelf prospectus expires August 2010. As at September 30, 2009, EPLP has not drawn on the shelf prospectus.

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, as at September 30, 2009:

	Due in 2009	Due in 2010	2011	2012	2013	Due in 2014 and beyond	Total contractual cash flows
Non-derivative financial liabilities:							
Long-term debt	$ 1	$ 247	$ 376	$ 104	$ 313	$ 738	$ 1,779
Interest payments on long-term debt	28	95	84	67	65	446	785
Accounts payable and accrued liabilities [1]	267	-	-	-	-	-	267
Other current liabilities	9	-	-	-	-	-	9
Loan commitments	6	-	-	-	-	-	6
Derivative financial liabilities:							
Net forward foreign exchange contracts	-	2	1	1	1	2	7
Net commodity contracts-for-differences	38	67	41	4	-	-	150
Total	$ 349	$ 411	$ 502	$ 176	$ 379	$ 1,186	$ 3,003

[1] Excluding accrued interest on long-term debt of $8 million.

(Unaudited, tabular amounts in millions of dollars)

22. Capital management:

The Company's primary objectives when managing capital are to safeguard the Company's ability to continue as a going concern, pay dividends to its shareholders in accordance with the Company's dividend policy, 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 short-term debt and long-term debt net of cash and cash equivalents, non-controlling interests (including preferred shares issued by subsidiary companies) and shareholder's equity. The following table represents the total capital of the Company:

	September 30, 2009
Long-term debt (including current portion) (note 10)	$ 1,771
Cash and cash equivalents	(64)
Net debt	1,707
Non-controlling interests (note 13)	1,975
Shareholders' equity	494
Total equity	2,469
Total capital	$ 4,176

The Company has no externally imposed requirements on its capital except as disclosed below.

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

- Maintenance of modified consolidated net tangible assets to consolidated net tangible assets ratio, as defined in the debt agreements, of not less than 0.90 to 1.0;
- Maintenance of 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 earnings before interest, income taxes, depreciation and amortization to interest expense, as defined in the debt agreements, of not less than 2.5 to 1.0.

EPLP has the following externally imposed requirements on its capital:

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

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

(Unaudited, tabular amounts in millions of dollars)

22. Capital management, continued:

For the period ended September 30, 2009, CPLP and EPLP complied with all externally imposed capital restrictions.

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

23. Related party balances and transactions:

The following summarizes the Company's related party balances and transactions with EPCOR and its subsidiaries. All transactions are in the normal course of operations, and are recorded at the exchange amount, which is the consideration established and agreed to by the parties.

		September 30, 2009
Balance sheet:		
Accounts receivable	(a)	$ 60
Other assets	(b)	7
Property, plant and equipment	(c)	9
Accounts payable – accrued interest on debt		12
Long-term debt (including current portion) (note 10)		876
Share capital (note 14)		-
Income statement:		
Revenues – energy sales		103
Energy purchases and fuel	(d)	6
Net financing expenses	(e)	6

(a) Accounts receivable includes $30 million relating to energy sales to subsidiaries of EPCOR and $30 million of amounts owed from EPCOR relating to operational cash transactions during the acquisition changeover period.

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

(c) Interest on long-term debt to EPCOR capitalized to property, plant and equipment.

(d) Includes energy distribution and transmission charges from subsidiaries of EPCOR.

(e) Net financing expenses on long-term debt to EPCOR.

(Unaudited, tabular amounts in millions of dollars)

24. Joint ventures:

The Company and the coal mine operator at the Genesee plant site each have a 50% interest in the Genesee Coal Mine Joint Venture. The joint venture partner operates the coal mine. Under agreements governing this joint venture, all coal mined is to be supplied to the Company's Genesee generation plant.

The Company holds 50% interests in the Genesee 3 Project, the Keephills 3 Project and the Taylor's Coulee Chute Hydro Project, and holds a 40% interest in the Joffre Cogeneration Project. The Company, through its EPLP subsidiary, also holds a 50.15% interest in the Frederickson power plant.

A financial summary of the Company's investments in joint ventures is as follows:

	September 30, 2009
Current assets	$ 43
Long-term assets	1,061
Current liabilities	56
Long-term liabilities	41
Revenues [1]	16
Expenses [2]	19
Net loss	(3)
Cash flows from operating activities	(1)
Cash flows used in investing activities	(79)
Cash flows from financing activities	66

[1] Excludes all revenues from Genesee 3, which are recorded as revenues by the Company but are not subject to the terms of the joint venture agreement.

[2] Excludes all costs of operating the Genesee Coal Mine Joint Venture which are recorded as fuel expenses by the Company.

Included in the Company's cash and cash equivalents at September 30, 2009 is its proportionate share of cash and cash equivalents which is restricted to use within joint ventures of $26 million.

Under the terms of the Company's interests in the Frederickson power plant, the Genesee 3 Project and the Keephills 3 Project, the Company and its respective partners have guaranteed financial and performance obligations under the joint venture agreements limited to $40 million, $50 million and $50 million respectively.

25. Employee future benefits:

Multiemployer defined benefit pension plan and defined contribution pension plan

Over 85% of the Company's employees are either members of the Local Authority Pension Plan or the Company's registered defined contribution plans. Accordingly, the majority of the Company's pension costs and obligations are accounted for as defined contribution plans.

25. Employee future benefits, continued:

Defined benefit plans

Prior to the transfer of employees resulting from the acquisition described in note 3, the effective date for the latest actuarial valuations of both the Company's registered and supplemental pension plans was December 31, 2007. The effective date of the next valuation for funding purposes is no later than December 31, 2010 for both plans. The plan assets and the accrued benefit obligation have been estimated as at September 30, 2009. The supplemental pension plan is a non-contributory plan that is unfunded at September 30, 2009.

As part of the Company's acquisition of its interest in EPLP from EPCOR, employees who transferred to Capital Power on July 1, 2009 became members of the Company's registered pension plan. The plan provides pension benefits based on an employee's years of service and their highest earnings over three consecutive years of employment. Retirement pensions will be increased annually by a portion of the increase in the Consumer Price Index. Prior to the Company's acquisition of its interest in EPLP, EPCOR had previously acquired the interest in EPLP from a third party. Under the terms of EPCOR's previous purchase and sale agreement, the previous plan sponsor transferred the pension liabilities for the Canadian employees and associated assets based on an actuarial valuation. At September 30, 2009, the actual transfer of assets has not yet occurred as regulatory approval required for transfer of the assets and obligations is still outstanding.

Plan benefit costs, assets and obligations

The accrued benefit liability and other employee future benefit liabilities, totalling $11 million and assumed as part of the acquisition described in note 3 are included in other non-current liabilities. Other employee future benefit liabilities consist mainly of obligations for benefits provided to employees on long-term disability leaves.

The market value of the defined benefit plan assets at September 30, 2009 was approximately $10 million.

Total cash payments for pension benefits in the three months ended September 30, 2009, consisting of cash contributed by the Company to the LAPP, other defined contribution and benefit plans and cash payments directly to beneficiaries for its unfunded pension plan, were $2 million.

26. 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, comprised of ManChief, Mamquam, Queen Charlotte, Southport, Roxboro, Kenilworth, Greeley, Williams Lake, Genesee units 1 and 2, Miller Creek and Brown Lake are accounted for as assets under operating leases. As at September 30, 2009, the carrying amount of such property, plant and equipment was $1,314 million, less accumulated depreciation of $12 million. The Company's revenue pursuant to the arrangements for the three months ended September 30, 2009 was $106 million.

(Unaudited, tabular amounts in millions of dollars)

27. Contingencies and commitments:

(a) The Company has committed to purchase new high efficiency gas-fired electric generating units for its Clover Bar Energy Centre. As at September 30, 2009, the estimated remaining total cost to be incurred is $30 million.

(b) The Company and TransAlta Corporation (TransAlta) are in the process of building Keephills 3, a 495 megawatt (MW) supercritical coal-fired generation plant at TransAlta's Keephills site. The construction is expected to be completed in 2011. As at September 30, 2009, the Company's 50% committed share of the estimated total remaining capital cost to be incurred is $287 million. As of October 30, 2009, the Board of Directors of CPC and TransAlta had approved additional funding and a revised schedule for the Keephills 3 project. The total project cost was revised from $1.8 billion to $1.9 billion and Capital Power's share was correspondingly revised from $903 million to $955 million resulting in an additional $52 million of costs expected to be incurred by the Company. As part of contractual arrangements, the Company and TransAlta have indemnified each other for up to $115 million during construction in the event that either party makes payments to the turbine supplier on behalf of the other party.

(c) EPLP has committed to the enhancement of the Southport and Roxboro facilities through 2009. As at September 30, 2009, the Company expects an additional $33 million (US$31 million) to be spent on the enhancement work. EPLP has committed to the upgrade of the gas turbine at the Oxnard facility, to be spent over the remaining months of 2009 and 2010. As at September 30, 2009, the Company expects an additional $17 million (US$16 million) to be spent on the upgrade of the Oxnard turbine.

(d) 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 the remainder of 2009 is $31 million. The actual amounts for the remainder of 2009 and future years may vary from estimates depending on generation volume and scheduled outages. It is expected that the annual payments over the remaining terms of the Alberta PPAs, as described in note 2(k), will range from $89 million to $182 million, adjusted for inflation, other than in the event of a forced outage.

(e) The Company has entered into a number of long-term energy purchase and transportation contracts and operating and maintenance contracts in the normal course of operations. Some of these energy purchase and transportation contracts are measured at their fair value and recorded on the consolidated balance sheet as derivative instruments assets and liabilities as appropriate. The energy purchase and transportation contract amounts disclosed below are based on gross settlement amounts. Approximate future payments under these contracts and under operating leases for premises are as follows:

	Energy purchase and transportation contracts	Operating and maintenance contracts	Operating leases
Fourth quarter of 2009	$ 56	$ 7	$ -
2010	113	28	2
2011	93	28	1
2012	78	28	4
2013	64	29	4
Thereafter	205	126	70
Total	$ 609	$ 246	$ 81

27. Contingencies and commitments, continued:

(f) The Company has committed to issue non-interest bearing notes receivable to the non-Capital Power syndicate members involved in the Sundance Swap transaction entered into by Capital Power subsidiaries prior to the acquisition of subsidiaries and assets from EPCOR as disclosed in note 3. 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 September 30, 2009, the Company has $13 million extended under such notes and their carrying amount of $8 million, after fair value adjustments, is included in other assets.

(g) On June 11, 2009, a Statement of Claim was filed against The City of Edmonton, the Mayor and Councilors of The City of Edmonton, EPCOR, EPCOR Power L.P.'s General Partner, EPCOR Power L.P. and Capital Power (the Co-defendants). The claim alleged, among other things, that The City of Edmonton acted beyond its power and contrary to the Municipal Government Act (Alberta) and did not observe an appropriate public process in connection with the initial public offering involving Capital Power. Based on its review of the available information, Capital Power believes that the claim is without merit and intends to vigorously defend itself. On June 26, 2009, Capital Power filed a Statement of Defence denying all of the allegations contained in the Statement of Claim. On July 3, 2009, the Alberta Court of Queen's Bench denied an application for an interim injunction to delay the closing of the Capital Power initial public offering and its acquisition of EPCOR's power generation business. The court was not satisfied that there was any real merit to the application. The Co-defendants have now applied to the Alberta Court of Queen's Bench for summary dismissal of this action against them.

On June 30, 2009, an Originating Notice was filed in the Court of the Queen's Bench of Alberta, Judicial District of Edmonton, by the Alberta Federation of Labour, the Canadian Union of Public Employees, Local 30, and the Civic Service Union 52. The Notice named The City of Edmonton, EPCOR Utilities Inc. and Capital Power Corporation as Respondents and requested that the transaction pursuant to which the power generation assets previously owned by EPCOR were transferred to Capital Power be overturned on the basis that certain purported actions taken by The City of Edmonton in connection with the initial public offering were allegedly outside the jurisdiction of the municipality under the Municipal Government Act. On September 25, 2009, the Alberta Court of Queen's Bench denied the application.

(h) The Company and its subsidiaries are subject to various other legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

28. Guarantees:

The Company has issued letters of credit for $90 million to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

Prior to the acquisition of subsidiaries and assets from EPCOR disclosed in note 3, EPCOR issued parental guarantees on behalf of former EPCOR subsidiaries to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements. At September 30, 2009, EPCOR continues to have outstanding parental guarantees on behalf of Capital Power totaling $1,315 million related to subsidiaries of Capital Power. In addition to this amount, EPCOR also has outstanding parental guarantees which do not have a defined limit, but which provide full support on any outstanding positions related to power purchase arrangements of Capital Power. The Company is working on transferring these parental guarantees over from EPCOR.

(Unaudited, tabular amounts in millions of dollars)

29. Geographic information:

	Three months ended September 30, 2009			
	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 433	$ 92	$ -	$ 525
Inter-area revenues	5	1	(6)	-
Total revenues	$ 438	$ 93	$ (6)	$ 525
Property, plant and equipment	$ 2,719	$ 480	$ -	$ 3,199
Goodwill	$ 95	$ 24	$ -	$ 119

Inter-area transactions occur in the normal course of operations and are recorded at the exchange amount which is the consideration established and agreed to by the parties.

30. Assets held for sale:

The Company's interest in the Battle River PSA will be disposed of on January 15, 2010. Since the final disposal will occur within one year of the balance sheet date, the remaining Battle River PSA assets on the consolidated balance sheet have been reclassified from power purchase arrangements to assets held for sale.

31. Subsequent events:

(a) On October 14, 2009, the Company announced it will be partnering with two third parties to develop what will be one of the world's largest Carbon Capture and Storage (CCS) projects, Project Pioneer (Pioneer). A letter of intent has been signed with the Province of Alberta, under which Pioneer will be eligible to receive funding from the province's $2 billion CCS fund. The Government of Canada is also contributing toward the project through its Clean Energy Fund. Pioneer entails the development of a CCS facility at the Keephills 3 power plant, currently under construction west of Edmonton. Pioneer will be designed to capture one million tonnes of greenhouse gas emissions annually. The development of Pioneer will not affect the construction schedule for Keephills 3, which is expected to enter commercial operation in early 2011.

(b) On October 13, 2009, a subsidiary of the Company, EPLP, announced a change in the frequency of its distributions to monthly from quarterly. Cash distributions of EPLP for periods commencing after September 30, 2009 will be made in respect of each calendar month instead of the quarters ending March, June, September and December of each year. EPLP also announced the launch of a Premium Distribution™ and Distribution Reinvestment Plan (the "Plan") that provides eligible unitholders with two alternatives to receiving the monthly cash distributions, including the option to accumulate additional units in EPLP by reinvesting cash distributions in additional units issued at a 5% discount to the Average Market Price of such units (as defined in the Plan) on the applicable distribution payment date. Under the Premium Distribution™ component of the Plan, eligible unitholders may elect to exchange these additional units for a cash payment equal to 102% of the regular cash distribution on the applicable distribution payment date.

31. Subsequent events, continued:

(c) On October 13, 2009, a subsidiary of the Company entered into a bought deal for the issuance of 4,000,000 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares") at a price of $25.00 per share, for aggregate gross proceeds of $100 million (the "Offering"). The Series 2 Shares will pay fixed cumulative dividends of $1.75 per share per annum, as and when declared, for the initial five-year period ending December 14, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. The Series 2 Shares are redeemable at $25.00 per share by the Corporation on December 31, 2014 and on December 31 every five years thereafter. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of the Corporation, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the Corporation, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 4.18%. The offering is expected to close on or about November 2, 2009, subject to certain conditions. The net proceeds will be used to repay outstanding bank indebtedness.