10065 Jasper Avenue
Edmonton AB T5J 3B1
Canada

EPCOR

April 1, 2008

British Columbia Securities Commission
Alberta Securities Commission
Saskatchewan Financial Services Commission
The Manitoba Securities Commission
Ontario Securities Commission
Autorité des marchés financiers
New Brunswick Securities Commission
Nova Scotia Securities Commission
Securities Division, Prince Edward Island
Securities Commission of Newfoundland and Labrador

Re: EPCOR UTILITIES INC. (the "Company") – Correction to Management's Discussion and Analysis ("MD&A") dated March 20, 2008

The Company has re-filed its MD&A dated March 20, 2008 to correct a reference to its 2007 Total assets. On page 6 of the MD&A, the Total assets for 2007 disclosed in the "Consolidated Financial Information" table has been corrected to "6,562". The re-filed MD&A is, in all other respects, identical to the MD&A that was filed on March 20, 2008.

Yours truly,

EPCOR UTILITIES INC.

Mark Wiltzen, CA
Senior Vice President and Chief Financial Officer

Management's discussion and analysis

This management's discussion and analysis (MD&A) dated March 20, 2008 should be read in conjunction with the audited consolidated financial statements of EPCOR Utilities Inc., hereinafter "the Company", "EPCOR", "we", "our" or "us", for the years ended December 31, 2007 and 2006. 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 upon the recommendation of the Audit Committee.

FORWARD-LOOKING STATEMENTS

Certain information in this MD&A is forward-looking and related to anticipated financial performance, events and strategies. When used in this context, words such as "will", "anticipate", "believe", "plan", "intend", "target" and "expect" or similar words suggest future outcomes. By their nature, such statements are subject to significant risks and uncertainties, which could cause EPCOR's actual results and experience to be materially different than the anticipated results. Such risks and uncertainties include, but are not limited to, operating performance, commodity prices and volumes, load settlement, regulatory and government decisions including changes to environmental and tax legislation, weather and economic conditions, competitive pressures, construction risks, availability and cost of financing, foreign exchange risks, availability of labour and management resources and the performance of partners, contractors and suppliers.

Readers are cautioned not to place undue reliance on forward-looking statements as actual results could differ materially from the plans, expectations, estimates or intentions expressed in the forward-looking statements. Except as required by law, EPCOR disclaims any intention and assumes no obligation to update any forward-looking statement even if new information becomes available, as a result of future events or for any other reason.

STRATEGY

EPCOR builds, owns and operates power plants, electrical transmission and distribution networks, water and wastewater treatment facilities, and infrastructure in Alberta, British Columbia and Ontario. We also provide energy and water services to residential and commercial customers. Through its investment in EPCOR Power L.P. (Power LP), EPCOR also has electricity generation operations in California, Colorado, New Jersey, New York State, North Carolina, Washington State and Indiana. Our strategy is delivered through an integrated structure with a portfolio of regulated and competitive businesses. We continue to look for opportunities for growth consistent with our balanced portfolio of businesses. By maintaining a strong base in regulated wires and water businesses and growing our commercial electricity and water operations, we intend to increase shareholder value as a leading North American supplier of energy and water services.

KEY PERFORMANCE INDICATORS

Our performance in meeting the goals of our strategy is measured through both financial and non-financial measures that are approved by the Board of Directors. The measurement categories include net income, operational excellence, safety, environment and reputation and are generally common to all of our business units operating within each business segment, and our shared service units.

Within each category, there are specific measures established for each business unit and shared service unit that are important to the results of the respective unit and in alignment with the

Company's strategy. For example, in Generation, plant availability is the key measure of operational excellence. In the customer service area of Energy Services, the key operational measures relate to call answer and handle times and reputation. Environment and safety performance are measured based on outcomes (for example, the number of incidents and accidents) and proactive activities (for example, applicable training) that are designed to minimize the potential for negative events such as lost time accidents or environmental incidents. Business unit measures under the reputation category are focused on customer related measures relevant to the particular business unit, such as customer satisfaction survey results.

For 2007, EPCOR's results were ahead of target for both its non-financial and financial performance measures.

SIGNIFICANT EVENTS

Keephills 3

On February 26, 2007, EPCOR and TransAlta Corporation (Transalta) announced their decision to build Keephills 3, a 495 megawatt (MW) supercritical coal-fired generation plant at TransAlta's Keephills site. Construction is expected to be completed by 2011. Our 50% committed share of the total capital cost is estimated to be $820 million. In addition, EPCOR 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.

Sale of power purchase arrangement

On January 1, 2007, we sold a 10% interest in the Battle River Power Syndicate Agreement (Battle River PSA) for cash proceeds of $59 million resulting in a pre-tax gain of $34 million. The associated income taxes were $4 million of expense and $7 million of refundable taxes which were charged to retained earnings. This sale was pursuant to the purchase and sale agreement entered into in June 2006 whereby EPCOR will sell its Battle River Power Purchase Arrangement (Battle River PPA) and related interest in the Battle River PSA to ENMAX Corporation (ENMAX) over a 4-year period ending in January 2010.

An initial 55% interest was sold for cash proceeds of $343 million on June 5, 2006. The Company also sold a 17.8% interest in the Sundance Power Syndicate Agreement to other syndicate members for $57 million. These transactions resulted in a pre-tax gain of $378 million and $51 million of associated income tax expense.

Energy Services reorganization

On January 1, 2007, we reorganized our two subsidiaries within the Energy Services segment that operate our regulated retail business. As part of the transactions, one of the subsidiaries, which was previously exempt from income taxes, became subject to income taxes under the Income Tax Act. Upon becoming taxable the subsidiary recognized future income tax assets of $10 million and a corresponding reduction in income tax expense.

Issue of preferred shares

In May 2007, EPCOR Power Equity Ltd. (EPEL), a subsidiary of Power LP (a subsidiary of EPCOR), issued 5 million 4.85% cumulative, redeemable First Preference Shares, Series 1 at a price of $25.00 per share with dividends payable on a quarterly basis at the annual rate of $1.2125 per share. Net proceeds of $121 million were used to repay a portion of amounts outstanding under Power LP's bridge acquisition credit facilities which were incurred for Power LP's acquisition of EPCOR USA Ventures LLC (Ventures), formerly Primary Energy Ventures LLC, in November 2006. On or after June 30, 2012, the shares are redeemable by EPEL at $26.00 per share, declining by $0.25 per share each year to $25.00 per share after June 30, 2016. The shares are not retractable by the holders.

The net proceeds from the issue are included in non-controlling interests in the consolidated balance sheet.

Limited partnership units offering by Power LP

In May 2007, Power LP issued 4,015,297 limited partnership units at $26.15 per unit for net proceeds of $102 million which were also used to repay amounts outstanding under Power LP's bridge acquisition credit facilities.

EPCOR, through wholly-owned subsidiaries purchased 1,228,681 limited partnership units to maintain its 30.6% interest in Power LP. The net proceeds from the units issued to the public are included in non-controlling interests in the consolidated balance sheet.

Redemption of preferred shares

On October 1, 2007, EPCOR Preferred Equity Inc., a subsidiary of the Company, completed the redemption of 8 million Cumulative Redeemable Perpetual First Preferred Shares, Series I at par for $200 million, funded from cash balances and debt.

The carrying value of the preferred shares prior to their redemption was $197 million, reflecting $200 million less issue costs of $3 million which were incurred when the preferred shares were issued in 2002. The $3 million difference was charged to non-controlling interests in the consolidated statements of income.

Asset-backed commercial paper

At December 31, 2007, the Company held $60 million ($71 million original cost) in Canadian non-bank sponsored asset-backed commercial paper (ABCP), all of which was purchased during the third quarter of 2007. The Company's ABCP is part of the $35 billion broader ABCP market that has been disrupted by the significant lack of liquidity that emerged in August 2007 and as a result, all of the Company's ABCP matured with no payment of principal, accrued interest or roll over. At the time, all of the conduits in which the Company's ABCP investments were held were rated R-1 (high) by DBRS Limited (DBRS), which is their highest rating for commercial paper. DBRS placed these conduits "Under Review with Developing Implications" following an announcement on August 16, 2007 that a consortium representing banks, asset providers and major investors, represented by the Pan-Canadian Investors Committee (Investors Committee), had agreed in principle to a long-term proposal and interim arrangements regarding the ABCP (the Montreal Accord). Under this proposed restructuring, the affected ABCP would be converted into term floating-rate notes maturing no earlier than the scheduled termination dates of the underlying assets. During the restructuring period, no payments of principal or accrued interest are being made on the ABCP (standstill arrangements). The standstill arrangements under the Montreal Accord were extended to December 14, 2007 on October 15, 2007 and to January 31, 2008 on December 31, 2007 and to February 22, 2008 on February 4, 2008.

On December 23, 2007, the Chairman of the Investors Committee announced the framework of the proposed restructuring of ABCP in which the Company has investments. The proposed restructuring is expected to be completed by April 30, 2008 and its key elements as they relate to EPCOR are:

(i) exchange of ABCP for floating-rate notes (FRN);

(ii) separation of ABCP conduit assets that are subject to U.S. sub-prime mortgage exposure;

(iii) pooling of certain ABCP conduit assets that are largely comprised of synthetic assets (assets other than conventional securitization assets such as leases and credit card receivables);

(iv) setting the maturity of the FRNs to match the maturities inherent in the underlying pooled assets which is expected to be 7 years;

(v) establishment of margin call facilities available to provide an aggregate of $14 billion of liquidity to support to the restructured assets;

(vi) modification of the margin call triggers in the ABCP conduits to make them more transparent and more trigger-risk remote.

On March 17, 2008 the Investors Committee applied for and received court approval for the restructuring plan to be carried out under the Companies' Creditors Arrangement Act. DBRS consequently downgraded 20 of the affected ABCP conduits to a "D" credit rating but re-affirmed its prior comments that the majority of the assets held by the affected conduits remain strong. We believe this action by DBRS is not reflective of the underlying credit quality of our ABCP investments. Accordingly, in assessing the valuation of our ABCP, we have considered the fundamental underlying credit ratings of our ABCP investments.

Under the proposed restructuring, EPCOR expects that $61 million of its original ABCP investment cost (in two conduits) will be exchanged for FRNs associated with the pooled synthetic asset conduit.

These FRNs will be comprised of senior and subordinated notes, the relative breakdown of which will be determined by an assessment by JPMorgan Chase & Co., the financial adviser to the Investors Committee. The senior notes are expected to receive the second highest investment-grade credit rating from an independent recognized credit rating agency. The subordinated notes may not be assigned a credit rating, however EPCOR expects that the subordinated notes could be investment grade.

Under the proposed restructuring, EPCOR expects that the remaining $10 million of its original ABCP investment cost (in one conduit) will be subject to a separate FRN, since the conduit is considered ineligible for pooling owing to its U.S. sub-prime mortgage exposure. These FRNs may not be assigned a credit rating. In February 2008, DBRS downgraded the original conduit to R-4, a speculative ratings class, but as noted by DBRS, approximately 80% of the underlying assets of this conduit are high investment grade.

Due to the expected longer term repayment and ongoing uncertainties, the ABCP investment is classified as non-current within other assets.

ABCP is a financial instrument and has been classified as held for trading and therefore is recorded at fair value. EPCOR has recognized a decrease in fair value of $11 million during the year, representing the difference between the original investment cost of $71 million and the estimated fair value of $60 million at December 31, 2007. There are no observable market prices for ABCP as at the balance sheet date. Accordingly, EPCOR has estimated the fair value using a probability-weighted discounted cash flow approach based on the assumed credit ratings and potential ratings actions on the applicable ABCP conduits under the proposed restructuring, observable interest rates and credit spreads for estimating future interest payments and applicable discount rates, the cost of margin call facilities (1.60% of the FRN investments), the cost of the proposed restructuring (0.001% of the FRN investments), estimated recovery periods based on the estimated lives of the underlying assets of the proposed restructuring conduits (7 years for pooled asset FRNs and 9 years for ineligible asset FRNs) and ranges of recoverability based on publicly available default statistics for credit-rated entities.

The estimate of fair value of ABCP is subject to significant risks and uncertainties including the timing and amount of future cash payments, the success of the proposed restructuring under the Montreal Accord, market liquidity, the quality and tenor of the underlying assets and instruments in the applicable conduits and the future market for the FRNs. Accordingly, the estimate of fair value of ABCP may change materially as events unfold and more information becomes available. The sensitivity of the estimated fair value to changes in key valuation assumptions, holding all other assumptions constant, is as follows:

Assumption	Change	Impact on estimated fair value ($ millions)
Amortization term	+/- 1 year	-/+ 1
Interest rate on FRN or cost of margin call facilities	+/- 1.00%	+/- 4
Credit ratings downgrade (increase in loss probability and losses realized)	3-notch downgrade	- 3 to - 5

If the restructuring is successful, it is possible that a secondary market for the FRNs will develop. If that occurs, there would be observable market prices for these investments that would be factored into our valuations. Such prices could be subject to market volatility and therefore could result in substantially different outcomes than our current valuation approach.

The estimate of fair value at December 31, 2007 of $60 million is lower than our estimate at September 30, 2007 of $67 million primarily due to changes in assumptions as a result of new information about the proposed restructuring, including the estimated FRN amortization period and margin facility costs, a ratings downgrade on one of the current conduits, and changes in interest rates, including credit spreads.

The Company continues to be in compliance with the financial covenants of its credit facilities and publicly-issued debt and has sufficient credit facilities and cash flows from operations to satisfy its financial obligations as they come due. Based on current information, the Company does not expect there will be a material adverse impact on its business as a result of this current ABCP liquidity issue.

Substantive enactment of tax rate reductions

Effective December 14, 2007, the Government of Canada passed Bill C-28 whereby the federal corporate income tax rate is scheduled to be reduced in increments over the period from January 1, 2008 to December 31, 2012, for a total reduction of 3.5 percentage points. These rate reductions were in addition to those included in the Government of Canada’s Bill C-52 which was enacted on June 22, 2007. The effect of Bill C-52 was to reduce the general corporate income tax rate from 19% to 18.5% commencing January 1, 2011.

As a result, we reduced the amount of future income tax balances by $1 million in the second quarter and $12 million in the fourth quarter, with corresponding increases in future income tax expense. The charge in the fourth quarter was composed of an $18 million charge for reductions in net future income tax assets partly offset by a $6 million future income tax recovery relating to future income tax balances for Power LP.

CONSOLIDATED FINANCIAL INFORMATION

($ millions)	2007	2006	2005
Revenues	$3,663	$2,931	$2,640
Net income from continuing operations	277	632	159
Net income from discontinued operations	-	10	28
Net income	277	642	187

Total assets	6,562	6,383	5,664
Long-term debt	2,139	2,179	2,083
Common share dividends	128	125	123

Analysis of net income

Net income from continuing operations for the year ended December 31, 2005	**$**	**159**
Net income from discontinued operations		28
Net income for the year ended December 31, 2005	**$**	**187**

Net income from continuing operations for the year ended December 31, 2005	**$**	**159**
Gain on sale of Battle River PSA and related transactions		327
Impact of recording a net future income tax asset associated with the restructuring of EPCOR Generation Inc. on January 3, 2006		117
2005 PILOT settlement adjustment		38
Higher income from combined operations of Genesee 3, Calpine, Kingsbridge I and Joffre		25
Higher realized gains on forward foreign exchange contracts		17
Lower financing expenses and preferred share dividends excluding Power LP financing		11
Regulatory decisions for 2005 distribution and transmission tariffs and 2005 RRT non-energy charges received in 2006		7
Higher water rates		7
Cumulative translation account adjustment for the sale of Frederickson to Power LP in 2006		(6)
2005 gain on sale of Alberta competitive electricity contracts and favourable settlement of litigation		(13)
Lower Ontario electricity margins		(21)
2006 impact of income tax rate reductions on future income tax assets and liabilities		(39)
Other		3
Increase in net income from continuing operations		473
Net income from continuing operations for the year ended December 31, 2006		**632**
Net income from discontinued operations		10
Net income for the year ended December 31, 2006	**$**	**642**

Net income from continuing operations for the year ended December 31, 2006	**$**	**632**
Impact of 2006 and 2007 income tax rate reductions on future income tax assets and liabilities, excluding Power LP		20
Higher water rates		16
Lower financing expenses and preferred share dividends excluding Power LP financing		15
Impact of recording a net future income tax asset associated with the Energy Services reorganization on January 1, 2007		10
Fair value changes in unhedged electricity positions and foreign exchange contracts		8
Higher income from Power LP		8
Cumulative translation account adjustment for the sale of Frederickson to Power LP in 2006		6
Lower maintenance costs on Genesee 1 and 2		5
Regulatory decisions for 2005 distribution and transmission tariffs and 2005 RRT non-energy charges received in 2006		(7)
Impact of forward foreign exchange contract settlements		(18)
Impact of recording a net future income tax asset associated with the restructuring of EPCOR Generation Inc. on January 3, 2006		(117)
Gain on sale of Battle River PSA and related transactions		(297)
Other		(4)
Decrease in net income from continuing operations		(355)
Net income from continuing operations for the year ended December 31, 2007		**277**
Net income from discontinued operations		-
Net income for the year ended December 31, 2007	**$**	**277**

Net income from continuing operations for the year ended December 31, 2007 was $277 million compared with $632 million for 2006. Net income from continuing operations decreased by $355 million for the year ended December 31, 2007 compared with the previous year primarily due to the sale of an interest in the Battle River PSA and related transactions in June 2006, partly offset by the sale of a further interest in January, 2007 as described under Significant Events. The reorganization of the Generation subsidiaries in January 2006, as described below, also contributed to the decrease. Excluding these transactions, net income from continuing operations increased by $59 million due to the net impact of the following:

- In June and December 2007, the Government of Canada substantively enacted tax legislation which reduced general corporate income tax rates as described under Significant Events. On April 10, 2006 and June 6, 2006, the Government of Alberta and the Government of Canada, respectively, reduced corporate income tax rates. The impact of these rate reductions on our future income tax assets and liabilities resulted in a $32 million charge to net income. This charge was composed of $39 million for reductions in net future income tax assets partly offset by a $7 million future income tax recovery relating to future income tax balances for Power LP. The impact of the 2007 and 2006 income tax rate reductions relating to Power LP is included as an offset to the higher income from Power LP in the table above.

- Water revenue was higher in 2007 compared with 2006 primarily due to increased rates as approved by The City of Edmonton.

- Financing expenses, excluding financing for Power LP, decreased primarily due to interest earned on higher cash balances in the first half of 2007, repayment in the third quarter of 2006 of the loan issued under a 3-year credit facility, and scheduled repayments of obligations to The City of Edmonton and non-recourse debt. The Company capitalizes an allowance for funds used during construction (AFUDC) to provide for the cost of capital invested in rate-regulated construction activities. AFUDC was higher in 2007 than in 2006 for the E.L. Smith water treatment plant (EL Smith) upgrade project. Capitalized interest on commercial construction activities was higher in 2007 for the Keephills 3 and Clover Bar Energy Centre generation projects. Preferred share dividends decreased due to the redemption of subsidiary Series A preferred shares on June 30, 2006 and EPEI preferred shares on September 30, 2007. In addition, in June 2007 the Government of Canada substantively enacted an effective income tax rate reduction relating to preferred share dividends paid since 2002 resulting in a decrease in non-controlling interests. These decreases were partly offset by the reduction in fair value of third-party ABCP that was recognized in 2007.

- Favourable fair value changes in the Alberta merchant and wholesale electricity positions were recognized in 2007 due to an increase in financial contracts for the forward sales of power (financial sales) which hedged anticipated energy revenues and were not designated as hedges for accounting purposes, combined with decreasing forward Alberta power prices in the second half of the year. In 2006, the fair value changes were unfavourable due to increased Alberta power forward prices. The increase in 2007 in the volume of financial sales contracts that were not designated as hedges for accounting purposes was due to the decrease in generation resulting from our reduced interest in the Battle River PSA and a planned outage at the Genesee 3 facility. These variances were partly offset by fair value losses on forward contracts for the purchase of U.S. dollars due to a weakening U.S. dollar in 2007, and lower fair value gains on the

Joffre Cogeneration Project (Joffre) contract-for-differences (CfD) due to less significant changes in Alberta natural gas and power forward prices in 2007.

- Net income from Power LP was higher in 2007 compared with the prior year primarily due to foreign exchange gains on the translation of Power LP's $US-denominated monetary assets and liabilities due to a strengthening Canadian dollar relative to the U.S. dollar in 2007.

  The foreign exchange gains were partly offset by a decline in the fair value of the natural gas supply contracts for Power LP's Ontario generation plants. These fair value adjustments were required by the new accounting standard for financial instruments. The contracts did not qualify for the designation under the accounting standard as expected purchase and use contracts and therefore were measured at fair value. There was no comparable adjustment in 2006 as the new accounting standard was effective January 1, 2007.

  In 2007, Power LP had higher interest expense on debt used to finance the 2006 acquisition of Ventures and on capital lease obligations assumed as part of the acquisition. Power LP recognized an impairment charge in the third quarter of 2007 in respect of certain Ventures management contracts, and experienced lower generation and pricing at its Curtis Palmer plant in 2007 compared with 2006.

  The impact of income tax rate reductions on future income tax balances for Power LP was a $6 million recovery in 2007 and a $7 million recovery in 2006.

- On August 1, 2006 the Company sold its interest in the Frederickson power plant (Frederickson) to Power LP. The recognition of previously deferred foreign exchange losses on the investment in Frederickson was partly offset by the recognition of a foreign exchange gain on repayment of the U.S. dollar debt designated as a hedge of the net investment in the foreign operations. The result was a net foreign exchange loss of $6 million in 2006. There was no comparable event or transaction in 2007.

- Maintenance costs for Genesee 1 and Genesee 2 were lower in 2007 due to changes in plant outage profiles. The scheduled plant outage at Genesee 2 lasted 24 days in 2006 whereas the Genesee 1 scheduled plant outage in 2007 lasted only 7 days.

- In the second quarter of 2006, the Alberta Utilities Commission (AUC, formerly Alberta Energy and Utilities Board) issued its decisions relating to our general tariff applications for electricity transmission, distribution and Regulated Rate Tariff (RRT) services in respect of the period from January 1, 2005 through December 31, 2006. The effect of these decisions relating to the period from January 1, 2005 to June 30, 2006 was recognized in the second quarter of 2006, of which $7 million related to 2005 service. There was no comparable rate decision in 2007.

- In 2007, net losses were realized on forward foreign exchange contracts used to hedge the purchase of generation assets with foreign currencies, whereas net gains were realized in 2006.

- The January 3, 2006 reorganization of the Generation subsidiaries resulted in the recognition of a future income tax asset associated with additional deductions available for income tax purposes, partly offset by the write-off of future income tax balances associated with the Alberta government's Payment in Lieu of Tax (PILOT) Regulation, thereby increasing income in 2006 by

$117 million.

Net income and net income from discontinued operations

Net income for the year ended December 31, 2006	**$**	**642**
Decrease in net income from continuing operations – see previous table		(355)
Decrease in income from operation of the Clover Bar generation plant		(10)
Decrease in net income		(365)
Net income for the year ended December 31, 2007	**$**	**277**

- In 2006, the estimate of costs to decommission the Clover Bar generation facility was reduced resulting in $10 million of income from discontinued operations.

Revenues

Revenues for the year ended December 31, 2005	**$**	**2,640**
Higher Power LP revenues		246
Unrealized fair value changes in derivative financial instruments		57
Higher natural gas trading		56
Regulatory decisions for 2005 distribution and transmission tariffs and 2005 RRT non-energy charges received in 2006		9
Lower energy revenues		(41)
2005 gain on sale of Alberta competitive electricity contracts and settlement of litigation		(21)
Commercial and other sales		(15)
Increase in revenues		291
Revenues for the year ended December 31, 2006		**2,931**
Higher natural gas trading activities		381
Higher Power LP revenues		229
Higher energy trading activities in the western U.S. region		67
Unrealized fair value changes on derivative instruments		17
Higher water revenues		17
Higher other energy revenues		9
Regulatory decisions for 2005 distribution and transmission tariffs and 2005 RRT non-energy charges received in 2006		9
Commercial and other sales		21
Increase in revenues		732
Revenues for the year ended December 31, 2007	**$**	**3,663**

Revenues increased $732 million in 2007 compared with 2006 due to the following:

- Power LP revenues were higher in 2007 primarily due to the acquisition of Ventures on November 1, 2006 and Frederickson on August 1, 2006 as well as favourable changes in the fair value of foreign exchange contracts used to hedge operating cash flows. The sale of Frederickson to Power LP had no impact on consolidated revenues and the offsetting decrease in revenues is included in the other energy revenues in the table above. These increases were partly offset by the non-recurrence of a settlement received from the Ontario Electricity Financial Corporation (OEFC) in the first quarter of 2006 and lower generation and pricing at the Curtis Palmer facility in 2007.

- Energy trading activities in the western U.S. region include new trading activities in the California market.

- The unrealized fair value changes on the Joffre CfD were insignificant in 2007 whereas they were unfavourable in 2006 due to significant changes in natural gas and power forward prices in Alberta. Unrealized fair value gains resulting from an increase in the volume of Alberta financial sales contracts that were not designated as hedges for accounting purposes, combined with a decrease in forward Alberta power prices in the second half of the year also resulted in higher revenues. The financial sales contracts were used to hedge anticipated energy revenues. The unrealized fair value gains on these contracts were offset by lower unrealized fair value gains on Ontario financial sales contracts resulting from significantly decreased trading activity in the Ontario market.

- Water revenues were higher in 2007 compared with 2006 primarily due to increased rates as approved by the regulator, The City of Edmonton.

- Other energy revenues include favourable settlements of financial sales contracts resulting from higher contract prices and increased volume. Revenues from RRT customers increased due to higher pricing. These increases were partly offset by a decrease in generation related to our reduced interest in the Battle River PSA, expiry of the short-term tolling arrangement with Calpine Power Income Fund (Calpine) and the sale of Frederickson to Power LP.

- Commercial and other sales were higher primarily due to an increase in streetlight and traffic signal construction activities for The City of Edmonton, new water and wastewater treatment facilities and infrastructure construction projects for third parties, and construction work for Distribution and Transmission's Downtown Edmonton Supply and Substation (DESS) project. Our Transportation department in the Water Services segment was contracted for some of the work on the DESS project and the intercompany profit was not eliminated from consolidated revenues as the transfer price for the constructed facilities is recognized for rate-making purposes as a valid cost of construction by the AUC, Distribution and Transmission's regulator.

Capital spending and investment

($ millions)	2007	2006	2005
Generation	$ 240	$ 63	$ 124
Distribution and Transmission	105	61	61
Energy Services	12	11	8
Water Services	122	104	51
Corporate – other	20	19	6
	499	258	250
Investment in Primary Energy Ventures LLC	-	371	-
Investment in Power LP	32	-	534
Other investment	-	3	-
	$ 531	$ 632	$ 784

Capital expenditures for property, plant and equipment increased in 2007 primarily due to increased investments in Generation and, Distribution and Transmission.

EPCOR and TransAlta commenced construction of Keephills 3, a 495 MW generation plant as described under Significant Events. EPCOR's capital expenditures on Keephills 3 were $142 million in 2007 and $10 million in 2006.

In December 2006, the AUC approved our proposal to construct three natural-gas-fired peaking power generation units for an aggregate gross generating capacity of 243 MWs at our Clover Bar Energy Centre site in northeast Edmonton. The first 43 MWs were commissioned in February 2008 with subsequent capacity to come on line by late 2010. Capital expenditures on the Clover Bar Energy Centre were $61 million in 2007 and $2 million in 2006.

In the first quarter of 2007, Distribution and Transmission commenced construction of the DESS project which consists of a new high-voltage transmission line that will supply electricity to downtown Edmonton. Capital expenditures on this project were $40 million in 2007 and $5 million in 2006. Water Services' construction on the EL Smith upgrade continued in 2007 with capital expenditures of $61 million in 2007 and $60 million in 2006. Both projects are scheduled for completion in 2008.

In May 2007, EPCOR purchased $32 million of Power LP limited partnership units to maintain its 30.6% ownership interest in Power LP, as described under Significant Events. On November 1, 2006, Power LP acquired 100% of Ventures for $366 million (US$326 million) plus acquisition costs of $5 million for a total purchase price of $371 million.

SEGMENT RESULTS

Generation

Generation operates more than 3,400 MW of generating capacity produced from 34 generating stations in Alberta, British Columbia, Ontario, Colorado, New York State, Washington State, California, New Jersey, North Carolina and Indiana.

The facilities owned by EPCOR include two generating units in Alberta that are subject to Power Purchase Arrangements (PPAs) and have a generating capacity of 820 MW. We also own 673 MW of coal-fired, gas-fired, hydro-electric, wind-powered and landfill gas-fired commercial generating capacity through six additional plants in Alberta, 40 MW of commercial generating capacity from two hydro-electric plants in British Columbia and approximately 40 MW of commercial generating capacity from a wind-powered project in Ontario.

Generation, as the manager, has the contractual right and obligation to operate Power LP's portfolio of 12 power generation plants in Canada and the U.S. with electric capacity of 869 MW, and a further 8 combined heat and power facilities in the U.S. with electric capacity of approximately 418 MW and a thermal energy capacity of approximately 3 million pounds per hour (lbs/hr). These power plants generate electricity from natural gas, waste heat, wood waste, water flow, coal and tire-derived fuel. Power LP also has a 15.4% equity interest in Primary Energy Recycling Holdings (PERH). The PERH power plants have an electric capacity of approximately 283 MW and a thermal capacity of approximately 2 million lbs/hr.

The Genesee 1 and Genesee 2 power generation units, which were previously rate-regulated through annual tariff applications, became subject to PPAs effective January 1, 2001 and continue to be rate-regulated by the guidelines of the *Electric Utilities Act* (Alberta). The electricity generated from these units is provided to the Alberta Balancing Pool as the PPA holder. In exchange for the rights to the electricity, we receive formula-based fixed capacity and variable payments which are intended to provide us with a reasonable opportunity to recover unit operating costs, a formula-based provision for income taxes and a rate of return on investment. The return on equity component is set at 4.5% over the rate of long-term Canada bonds. In addition, we receive incentives and pay penalties when the output available from the generation unit exceeds or falls below target availability levels set out in the PPAs. The target availability levels were originally set with the expectation that the incentives and penalties would net to zero over the life of the PPAs. EPCOR's Clover Bar and Rossdale plants also became subject to PPAs in 2001 but those PPAs are no longer in effect.

Although the units operating under PPAs are rate-regulated, they do not meet the criteria for rate-regulated accounting under generally accepted accounting principles. Accordingly, the generation units are accounted for as unregulated facilities in accordance with the commercial terms and conditions inherent in the PPAs. Key to the earnings performance of generation units operating under PPAs is managing the costs of the units and ensuring that they are able to meet or exceed the target availability levels.

The Clover Bar PPA was terminated effective September 30, 2005 at which time decommissioning of the plant commenced. All operating results relating to the Clover Bar facility subsequent to the PPA termination were reported under discontinued operations and excluded from the Generation segment results. The plant was decommissioned in 2007.

The Rossdale PPA expired on December 31, 2003 and the plant was operated as a commercial generation unit throughout 2004. An ancillary services contract with the Alberta Electric System Operator (AESO) for continued operation of the Rossdale plant was finalized in 2005. The agreement defers decommissioning of the Rossdale generation plant until 2009 to provide ongoing transmission system reliability for the city of Edmonton and back-up generating capacity for the province of Alberta.

Electricity generated from commercial generation plants is sold either under long-term contracts to creditworthy third parties or into the wholesale market where the plant is located. Our general objective is to contract the majority of our non-base-loaded commercial plants' capacity. Key to the earnings of these plants is ensuring that the plants are dispatched (directed to supply electricity to the power grid) as economically as possible, as well as ensuring that operating costs, including fuel, are appropriately controlled and that the plants are well maintained.

Generation operating income

Year ended December 31		2007	2006
Generation results			
(including intersegment transactions, $ millions)			
Revenues		$ 1,016	$ 777
Expenses	Energy purchases and fuel	312	102
	Operations, maintenance, administration and foreign exchange	148	176
	Franchise fees and taxes other than income taxes	17	18
	Depreciation, amortization and asset retirement accretion	172	151
		649	447
Operating income before corporate charges		367	330
Corporate charges		45	26
Operating income		**$ 322**	**$ 304**

Operating income for the year ended December 31, 2006	**$**	**304**
Higher Power LP operating income		59
Write-down of project capital costs in 2006		8
Lower maintenance costs on Genesee 1 and 2		7
Cumulative translation account adjustment for the sale of Frederickson to Power LP in 2006		6
Lower PPA capacity payments		(5)
Realized foreign exchange loss		(18)
Unrealized fair value changes in derivative financial instruments		(43)
Other		4
Increase in operating income		18
Operating income for the year ended December 31, 2007	**$**	**322**

For the year ended December 31, 2007, Generation's operating income increased by $18 million from the prior year primarily due to the following:

- Power LP contributed $141 million of operating income in 2007 compared with $82 million in 2006 due to the impact of the Ventures and Frederickson acquisitions commencing on their respective purchase dates of November 1, 2006 and August 1, 2006. Revenues and expenses from Power LP increased $229 million and $170 million, respectively, from 2006 to 2007. The sale of Frederickson to Power LP had no impact on consolidated results and the offsetting decrease in operating margin is included in the unfavourable other variance in the table above.

  Power LP's revenues were also impacted by favourable changes in the fair value of forward foreign exchange contracts, partly offset by the non-recurrence of the settlement payment received from the OEFC and recognized in the first quarter of 2006, and lower revenues from the Curtis Palmer plant in 2007.

  Power LP's expenses also increased due to unfavourable fair value changes in its natural gas supply contracts. An impairment charge in respect of certain Ventures management contracts was recognized in the current year with no corresponding amount in the prior year. These increases were partly offset by unrealized foreign exchange gains in 2007 on the translation of higher U.S. dollar debt balances for the Frederickson and Ventures acquisitions, which were due to a strengthening Canadian dollar relative to the U.S. dollar.

- Capital costs related to a project at the Frederickson generating plant were written down in 2006 as the project was cancelled. Capital costs related to the Kingsbridge II project were also written down in 2006 as the project is being re-examined.

- Maintenance costs were lower in 2007 as the plant outage for Genesee 2 lasted 24 days in 2006 whereas the Genesee 1 outage in 2007 had a reduced scope and lasted only 7 days.

- In accordance with the PPAs for Genesee 1 and Genesee 2, we receive capacity payments from the Alberta government's Balancing Pool. Income taxes, based on statutory rates, and the PPA rate base are two of the factors in the formula for determining capacity payments and reductions in both of these variables resulted in lower payments in 2007 compared with 2006.

- The Company realized losses on foreign exchange contracts entered into in anticipation of asset purchases related to the Clover Bar Energy Centre and Keephills 3 projects, due to a strengthening Canadian dollar. In comparison, the Company realized gains on EURO forward foreign exchange contracts related to the Kingsbridge I and II projects in 2006.

- The generation from the Joffre plant is subject to a CfD which is a financial agreement whereby the difference between the cost of electricity at spot prices and variable operating costs for the contracted volume, is remitted by one counterparty to the other. In 2007, the unrealized fair value changes on the CfD were insignificant. However, in 2006, they decreased revenues and expenses by $18 million and $45 million respectively, due to significant changes in Alberta natural gas and power forward prices.

  Unrealized fair value changes on foreign exchange contracts entered into in anticipation of asset purchases related to the Clover Bar Energy Centre and Keephills 3 generation projects decreased operating income and increased expenses year over year by $16 million due to a strengthening Canadian dollar. These foreign exchange contracts are expected to substantially hedge the economic changes caused by foreign currency movements on these asset purchases. However, they have not been recognized as hedges for accounting purposes.

	2007	2006
Electricity generation (000s of megawatt-hours)		
Generation units owned by EPCOR		
Coal generation units	8,147	8,136
Natural gas generation units	305	451
Hydro and wind generation units	316	250
	8,768	8,837
Generation units owned by Power LP		
Natural gas or waste heat units	3,495	1,934
Wood waste or waste heat units	1,387	817
Hydro generation units	574	648
	5,456	3,399
Total	**14,224**	**12,236**

	2007	2006
Generation plant availability (%)		
Generation units owned by EPCOR		
Coal generation units	97	96
Natural gas generation units	96	94
Hydro and wind generation units	88	93
Generation units owned by Power LP		
Natural gas or waste heat generation units	93	96
Coal/tire-derived fuel, wood-waste or waste-heat generation units	95	95
Hydro generation units	89	91
Total	**95**	**95**

Generation maintains a fleet of high quality power plants with good geographic, fuel source and counterparty diversification. We have a strong track-record of maximizing efficiency, productivity and reliability of our facilities. The overall availability of our facilities was 95% in both 2007 and 2006. The lower availability of EPCOR's hydro and wind generation units was due to an increase in planned outages in 2007. The lower availability of Power LP's hydro units was due to an increase in outages at the Curtis Palmer and Mamquam plants in 2007.

Generation will continue to operate and safely maintain EPCOR's generation assets. In 2008, all three Genesee units will be required to shut down to accommodate AESO's upgrade of the high-voltage transmission lines in the Genesee Keephills area. Based on negotiations with AESO, EPCOR expects to be compensated for certain direct and indirect costs of the outage.

The Company continues to pursue commercially and environmentally viable acquisition and development opportunities for generation plants to help grow the business in both Canada and the U.S. The Company has commenced construction of three new gas-fired generating units at the Clover Bar Energy Centre site and commercial operations at one of the units began in February 2008. The other two units are scheduled for completion by the end of 2010. In 2007, the Company and TransAlta started the development and construction of Keephills 3, a 495 MW supercritical coal-fired generation plant at TransAlta's Keephills site with completion targeted for 2011. These generation plants will assist in providing capacity to Alberta's electric system and provide additional growth for EPCOR. The Company continues to review the design and schedule of the Kingsbridge II wind farm.

Distribution and Transmission

Distribution and Transmission earns income principally by transmitting high-voltage electricity from generation plants to points of distribution and, from there, distributing low-voltage electricity to retailers' end-use customers. Our distribution and transmission assets are located in and around The City of Edmonton and are regulated by the AUC. We earn provincially regulated distribution and transmission tariffs intended to allow us to recover our prudent costs and earn a fair rate of return on our distribution and transmission infrastructure. Effective January 1, 2007 the AUC approved the merger of distribution assets with transmission assets into a new legal entity, EPCOR Distribution and Transmission Inc. (EDTI) to improve efficiencies and create cost savings that will flow back to the consumer. Distribution and Transmission is also responsible for meter reading for all electricity suppliers within The City of Edmonton service area and acting as the load settlement agent for The City of Edmonton.

Distribution and Transmission operating income

Year ended December 31		2007	2006
Distribution and Transmission results			
(including intersegment transactions, $ millions)			
Revenues	Distribution	$ 201	$ 206
	Transmission	36	40
	Commercial and other	10	12
		247	258
Expenses	Energy purchases and fuel	72	79
	Operations, maintenance, administration and foreign exchange	56	59
	Franchise fees and taxes other than income taxes	39	38
	Depreciation, amortization and asset retirement accretion	27	26
		194	202
Operating income before corporate charges		53	56
Corporate charges		14	13
Operating income		**$ 39**	**$ 43**

Operating income for the year ended December 31, 2006	**$ 43**
2005/2006 regulatory decisions for distribution and transmission tariffs	(6)
Operations, maintenance and administration and other	2
Decrease in operating income	(4)
Operating income for the year ended December 31, 2007	**$ 39**

For the year ended December 31, 2007, Distribution and Transmission operating income decreased

$4 million from the prior year. The 2005/2006 rate decision was received in June 2006 and resulted in the recognition of $8 million of revenue and $2 million of administration expenses relating to 2005. Energy purchases were lower due to increased Balancing Pool rebates from the AESO and reduced transmission charges.

	2007	2006
Distribution reliability and volumes		
Reliability (system average interruption duration index in hours)	1.14	0.73
Electricity distribution (000s of megawatt-hours)	7,076	7,096

The strategic focus of Distribution and Transmission continues to be operational excellence. Reliability rates for our Edmonton distribution system continue to be among the best in Canada. Our primary measure of distribution system reliability is System Average Interruption Duration Index (SAIDI) which we attempt to minimize. This measure captures the annual average number of hours of interruption experienced by our customers, including scheduled and unscheduled interruption to our primary distribution circuits. In 2007, we experienced a SAIDI of 1.14 hours compared with 0.73 hours in 2006. This increase was primarily due to unusually bad weather in 2007 including three major storms and a significant increase in the number of failed underground cables on EDTI's system. Commencing in 2008, EDTI is undertaking an aggressive program to rejuvenate or replace a number of aging underground cables which are experiencing failures. Electricity distribution volumes decreased modestly from 2006 to 2007 due to the loss of three large industrial customers, partly offset by higher consumption resulting from population growth in the Edmonton region.

Distribution and Transmission's earnings and cash flow are driven from its rate base, which requires continuous maintenance and upgrading to accommodate growth in The City of Edmonton. Distribution and Transmission will complete the DESS project and will be adding a new substation at the Clover Bar Energy Centre site in 2008. Once complete, these investments will be added to Distribution and Transmission's rate base and provide additional earnings and cash flows. Distribution and Transmission is reviewing transmission expansion opportunities in the Heartland area northeast of Edmonton. An increase in electricity demand is forecasted for the region due to rapid industrial growth. We are reviewing route selection and construction opportunities for one or more transmission lines to service the area.

Energy Services

Energy Services earns income from the supply of electricity and to a lesser extent natural gas, to end-use customers in Alberta. Electricity revenues are earned at regulated rates from RRT customers and at rates set by competitive retail contracts to commercial and industrial customers, both designed to cover the costs of supplying electricity (including the costs of the commodity, credit risk, and volume risks) and provide an appropriate margin. Natural gas revenues are earned under competitive retail contracts. In addition, Energy Services has wholesale contracts with Alberta Energy Savings Limited Partnership (AESLP) to supply their retail customers with both natural gas and electricity.

Energy Services also manages our overall electricity and natural gas portfolio in all markets in which we operate. To balance supply and demand, electricity and natural gas are purchased and sold under physical and financial transactions with the objective of matching volumes and terms or taking positions within limits established under prudent risk management policies. Electricity supply is also provided through EPCOR's interests in the Sundance and Battle River PPAs and EPCOR's merchant plants, Genesee 3 and Joffre. The electricity from all these sources is used to help balance and optimize the Company's electricity portfolio and satisfy customer electricity requirements. As part of its mandate, Energy Services also participates in the ancillary services (electricity reserves) market with its merchant plants.

Energy Services operating income

Year ended December 31			2007		2006
Energy Services results					
(including intersegment transactions, $ millions)					
Revenues	Energy revenues	$	2,382	$	1,926
	Commercial and other		35		37
			2,417		1,963
Expenses	Energy purchases		2,149		1,745
	Operations, maintenance, administration and foreign exchange		80		79
	Depreciation, amortization and asset retirement accretion		30		28
			2,259		1,852
Operating income before corporate charges			158		111
Corporate charges			26		22
Operating income		**$**	**132**	**$**	**89**

Operating income for the year ended December 31, 2006	**$**	**89**
Unrealized fair value increases in derivative financial instruments		63
Lower Ontario electricity margins		(3)
Lower Alberta electricity margins		(3)
Higher operations, administration, foreign exchange and corporate charges for non-regulated operations		(10)
Other		(4)
Increase in operating income		43
Operating income for the year ended December 31, 2007	**$**	**132**

For the year ended December 31, 2007, Energy Services' operating income increased by $43 million from the prior year due to the net impact of the following:

- The unrealized fair value changes in our financial electricity contracts were favourable compared with the prior year due to an increase in financial sales contracts in our Alberta portfolio that were not designated as hedges for accounting purposes and were entered into during the first half of the year. The volume of these instruments that were not designated as hedges for accounting purposes was higher in 2007 due to decreased generation resulting from our reduced interest in the Battle River PSA. The favourable change in fair value was due to a net short position for the financial electricity contracts held in 2007, combined with decreased forward Alberta power prices in the second half of the year. In 2006 the financial electricity contracts were in a net short position while forward Alberta power prices increased resulting in unrealized fair value losses.

  Energy revenues and purchases relating to unrealized fair value changes in our derivative instruments were lower in 2007 than in 2006 by $1 million and $64 million, respectively. Energy Services significantly reduced its trading activity in the Ontario power market which reduced both revenues and expenses. However, the decrease in energy revenue was partly offset by increases in financial sales contracts in the Alberta market that were not designated as hedges for accounting purposes.

- Ontario electricity margins were lower due to the expiry in 2007 of a number of our contracts with wholesale customers and contracts for the supporting power supply.

- Alberta electricity margins were lower in 2007 compared with 2006 due to our reduced interest in the Battle River PSA. We also did not have the benefit of the short-term tolling arrangement with Calpine for the operation of their Calgary Energy Centre which was in place for most of 2006.

  The Genesee 3 facility is operated by the Generation segment under a tolling arrangement with Energy Services, whereby Energy Services pays a fixed capacity fee plus a variable cost fee in exchange for the right to control the dispatch of generation from the facility. Margins from Genesee 3 were lower in 2007 due to reduced generation resulting from an outage in October 2007 and other de-rates earlier in the year.

  Income from our Joffre facility depends on the plant's spark spread which represents the difference between Alberta power prices and the rate for variable costs, primarily the cost of natural gas, required to produce electricity. If the price of power is higher than the cost of natural gas to produce electricity, the spark spread is favourable and vice versa. Income from our Joffre facility was lower in 2007 compared with 2006 due to a lower spark spread.

  Energy margins from our RRT customer base were lower in 2007 compared with 2006 primarily due to changes in the Energy Price Setting Plan (EPSP) for energy charges effective July 1, 2006.

  These decreases in Alberta electricity margins were partly offset by a higher volume of financial sales contracts which settled at higher contract prices compared with the prior year, combined with a lower Alberta power price.

- Alberta electricity revenues and purchases increased primarily due to the higher volume of financial contracts which settled at higher prices. Pricing for RRT energy revenues and purchases were higher under the new Regulated Rate Option (RRO) and EPSP, effective July 1, 2006, but did not result in a higher margin. These increases in Alberta electricity revenues and purchases were partly offset by lower rates for non-energy charge revenues, our reduced interest in the Battle River PSA, lower generation from Genesee 3, the absence of the Calpine short-term tolling arrangement and lower prices for purchases from the Alberta Power Pool.

- Higher natural gas trading activities also contributed to higher energy sales and purchases, but had minimal impact on energy margins.

- During 2007, merchant trading activities were entered into for the first time in the Pennsylvania, New Jersey, Maryland and California electricity markets which contributed to higher energy sales and purchases. The impact of this new activity on energy margins was insignificant.

- Operating expenses for the non-regulated portion of Energy Services were higher in 2007 compared with 2006 primarily due to higher employee short-term incentive compensation and foreign exchange losses on U.S. transactions.

Energy Services' retail customer sales volumes, which exclude electricity and natural gas trading activities, were as follows:

	2007	2006
Retail sales		
Electricity (000s of megawatt-hours)		
RRT	5,711	5,710
Default	868	872
Competitive	3,267	3,583
	9,846	10,165
Natural gas (000s of gigajoules)	1,880	2,044

	2007	2006
Energy supply (MWh)		
Battle River PPA generation	1,301	2,253
Sundance PPA generation	2,514	2,828
Genesee 3 generation	1,796	1,887
Joffre generation	270	256
	5,881	7,224
Calpine short-term tolling arrangement	-	715
	5,881	7,939

Overall customer sales volumes declined in 2007 from 2006 primarily due to the expiry of some commercial and industrial customer contracts in Ontario and Alberta. Power sales volumes for RRT and default customers remained consistent from 2006 to 2007. Natural gas sales volumes declined due to a reduction in industrial gas contracts.

In 2006, we began repositioning our power portfolio by selling interests in our Battle River and Sundance PPAs. The sales of additional interests in the Battle River PSA in the period from 2007 to 2010 will continue to reduce our power supply volumes, which will be replaced over time with new production from the Clover Bar Energy Centre and Keephills 3 facilities as they come on line.

Energy Services will continue to play a key role in EPCOR's growth as it continues to pursue opportunities, and manage EPCOR's electricity and natural gas portfolios. As new generation assets are added to EPCOR's fleet, Energy Services will contract with Generation for the capacity of the new assets and optimize the value of those investments by selling the electricity to the market or end-use customers. Energy Services is also working to add value to existing operations by identifying trading and marketing opportunities in each region we operate.

Water Services

Water Services earns income primarily from the treatment, distribution and sale of water while ensuring public health standards are exceeded. The majority of Water Services' income is earned through a performance-based rate (PBR) tariff charged to its Edmonton customers. The PBR tariff is intended to allow Water Services to recover its costs and earn a fair rate of return while providing an incentive to manage costs below the inflationary adjustment built into the PBR rate. The key to maintaining earnings on water sales is to provide sufficient quantities of high quality water while controlling costs.

Water Services manages EPCOR's Transportation Services business which provides competitive contract-based commercial services related to installation, maintenance and repair of street lighting, traffic signal, light rail transit and trolley facilities. In addition, Water Services provides competitive contract-based water and wastewater services to commercial, industrial and municipal customers. The key to earning satisfactory margins on these contracts is to satisfy the terms of the contract while controlling or reducing operating costs.

Water Services operating income

			2007		2006
Water Services results					
(including intersegment transactions, $ millions)					
Revenues	Water revenues	$	136	$	119
	Commercial and other		128		85
			264		204
Expenses	Operations, maintenance, administration and foreign exchange		163		125
	Franchise fees and taxes other than income taxes		10		8
	Depreciation, amortization and asset retirement accretion		18		17
			191		150
Operating income before corporate charges			73		54
Corporate charges			14		10
Operating income		**$**	**59**	**$**	**44**

Operating income for the year ended December 31, 2006	**$**	**44**
Increased water rates		16
Higher commercial services activity		6
Higher operations and maintenance		(3)
Higher depreciation, administration and other		(4)
Increase in operating income		15
Operating income for the year ended December 31, 2007	**$**	**59**

For the year ended December 31, 2007, Water Services' operating income increased by $15 million from the prior year due to the net impact of the following:

- Water revenues were higher in 2007 compared with 2006 primarily due to increased rates as approved by the regulator, The City of Edmonton, which were implemented in the second quarter of 2007.

- Transportation and other commercial services revenues and expenses increased in 2007 over 2006 by $41 million and $35 million respectively, primarily due to an increase in streetlight and traffic signal construction activities for The City of Edmonton and contracting income from Distribution and Transmission's DESS project. Also, new commercial services construction projects are in progress for the City of Wetaskiwin and the Town of Taber in Alberta, and for the 2010 Vancouver Olympics Committee.

- Operations and maintenance costs increased in 2007 over 2006 due to a higher incidence of distribution main breaks and unplanned maintenance at the Rossdale and EL Smith plants. Water treatment costs were also higher due to more spring run-offs and unfavourable water conditions due to wet weather in 2007.

	2007	2006
Water volumes for The City of Edmonton and surrounding region		
Water sales (megalitres)	124,696	125,106

Water Services owns 4 and operates 16 water treatment and distribution facilities. As well, it operates 19 wastewater and collection facilities in Alberta and British Columbia. Our core market is stable as we are the sole supplier of water within The City of Edmonton. In 2007, we saw a slight decrease in water volumes, primarily due to cooler and wetter weather on average compared with 2006, and the impact of water conservation efforts in the Edmonton region. Operationally, the facilities we own or manage performed well in both 2006 and 2007.

The completion of the EL Smith upgrade in 2008 will provide water capacity necessary to meet the anticipated growth in the city of Edmonton. Asset components are being added to the rate base as they are placed into service. The water rates for 2007 and 2008 reflect the costs of the upgrade project resulting in additional cash flow and earnings.

Business development efforts in the Alberta commercial marketplace are expected to contribute to additional growth in cash flow and earnings in 2008 and beyond. In late 2007, Water Services entered into agreements to design, build, operate and finance water and wastewater facilities for the City of Wetaskiwin and the Town of Chestermere. The Company is also close to completing commercial agreements with other municipal and industrial partners for the construction and operation of treatment facilities in 2008.

CONSOLIDATED BALANCE SHEETS

Significant changes in consolidated assets: December 31, 2007 and 2006				
($ millions)	2007	2006	Increase (decrease)	Explanation
Cash and cash equivalents	$ 79	$ 260	$ (181)	Refer to cash flows summary below.
Accounts receivable (including income taxes recoverable)	591	647	(56)	Reflects lower energy pricing on wholesale power settlements and lower receivables for Genesee 3, due to lower Alberta power prices, partly offset by higher commercial services receivables.
Derivative instruments assets (current)	104	26	78	Implementation of new financial instruments accounting standards for physical power and natural gas purchase and sales contracts and derivatives used in cash flow hedges of electricity.
Other current assets	74	70	4	Reflects changes in inventories, prepaid expenses and current portion of future income tax assets.
Property, plant and equipment	4,216	3,908	308	Reflects 2007 capital expenditures in excess of depreciation and amortization expense.
Power purchase arrangements	679	757	(78)	Sale of 10% interest in Battle River PSA and amortization of remaining PPAs in 2007.
Contract and customer rights and other intangible assets	179	207	(28)	Amortization of customer and contract rights.
Derivative instruments assets (non-current)	116	20	96	Implementation of new financial instruments accounting standards for physical power and natural gas purchase and sales contracts and derivatives used in cash flow hedges of electricity, combined with an increase in the fair value of foreign exchange derivatives.
Future income tax assets (non-current)	103	127	(24)	Reflects enactment of future tax rate reductions partly offset by increase in deductions available for tax purposes resulting from implementation of new financial instruments accounting standards.
Goodwill	185	183	2	
Other assets	236	178	58	Purchase and subsequent reduction in fair value of ABCP.

Significant changes in consolidated liabilities and shareholder's equity: December 31, 2007 and 2006				
($ millions)	2007	2006	Increase (decrease)	Explanation
Short-term debt	$ 138	$ 216	$ (78)	Reflects the repayment of Power LP's borrowing under its bridge acquisition credit facility, partly offset by new commercial paper borrowings.
Derivative instruments liabilities (current)	136	24	112	Implementation of new financial instruments accounting standards for physical power and natural gas purchase and sales contracts and derivatives used in cash flow hedges of power.
Accounts payable and accrued liabilities	615	608	7	Reflects increased capital accruals, partly offset by lower Alberta power prices on wholesale electricity settlements.
Other current liabilities	98	124	(26)	Reflects a reduction in future and current income tax liabilities due to payments and rate reductions substantively enacted in 2007, partly offset by an increase in future income taxes payable for the gain on sale of the interest in the Battle River PSA.
Long-term debt (including current portion)	2,139	2,179	(40)	Ongoing scheduled debt repayments on The City of Edmonton debentures and non-recourse financing, reclassification of debt issue costs from other assets effective January 1, 2007 and a net decrease in Power LP's debt with the replacement of acquisition financing and lease obligations with two senior unsecured notes issues. Partly offset by a credit facility draw-down in 2007.
Derivative instruments liabilities (non-current)	78	27	51	Implementation of new financial instruments accounting standards for physical power and natural gas purchase and sales contracts, and derivatives used in cash flow hedges of power.
Other non-current liabilities	125	127	(2)	Reflects changes in asset retirement obligations and employee future benefits.
Future income tax liabilities (non-current)	126	84	42	Reflects the enactment of the SIFT legislation, partly offset by the impact of tax rate reductions that were substantively enacted in 2007.
Non-controlling interests	740	751	(11)	Reflects redemption and issue of preferred shares by subsidiary companies. Also reflects non-controlling interests' share of Power LP distributions less unit offering and Power LP income. Partly offset by opening adjustment upon implementation of financial instruments accounting standards attributable to non-controlling interests.
Shareholder's equity	2,367	2,243	124	Net income and adjustments to retained earnings upon implementation of financial instruments accounting standards, partly offset by common share dividends and refundable income taxes. Also reflects adjustment to accumulated other comprehensive income upon implementation of financial instruments accounting standards and other comprehensive income for 2007.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Cash inflows (outflows) and cash position:

	($ millions)					
	Years ended December 31					
	2007	2006	Change	2006	2005	Change
Operating	$ 541	$ 589	$ (48)	$ 589	$ 479	$ 110
Investing	(469)	(303)	(166)	(303)	(757)	454
Financing	(253)	(116)	(137)	(116)	(88)	(28)
Opening cash and cash equivalents	260	90	170	90	456	(366)
Closing cash and cash equivalents	$ 79	$ 260	$(181)	$ 260	$ 90	$ 170

Operating changes:

The 2006 to 2007 decrease in cash inflows reflects changes in non-cash working capital due to the timing of receipts and payments, reduced cash flow from the Calpine short-term tolling arrangements and the Battle River PPA, and net realized losses on forward foreign exchange and interest rate contract settlements.

Investing changes:

The 2006 to 2007 increase in investing activities reflects higher capital expenditures in 2007, primarily for the Keephills 3 and Clover Bar Energy Centre generation projects, the EL Smith upgrade and the DESS project. Investing activities in 2007 also included the purchase of ABCP and the sale of a smaller interest in the Battle River PSA. Investing activities in 2006 included Power LP's purchase of Ventures, but no purchases of ABCP as it was classified as a cash equivalent in 2006.

Financing changes:

The 2006 to 2007 increase in financing outflows reflects higher short-term debt repayments, lower long-term and short-term debt issues and higher subsidiary company preferred share redemptions in 2007. These increases were partly offset by a subsidiary company preferred share issue and lower long-term debt repayments in 2007.

LIQUIDITY AND CAPITAL RESOURCES

($ millions) Years ended December 31	2007	2006	2005
Cash flow from operations[1]	$ 517	$ 547	$ 493
Long-term borrowings during the year	395	406	200
Cash and cash equivalents, at end of year	79	260	90
Short-term debt, at end of year	(138)	(216)	(29)
Ratios[1]			
Debt to equity[2]	42:58	44:56	44:56
Interest coverage (excluding gain on sale of PPA and related transactions) on long-term debt:			
Income before financing and taxes[3]	3.2 X	3.0 X	3.4 X
Income from continuing operations before financing and taxes [4]	3.2 X	2.9 X	3.1 X
Income before financing, taxes, depreciation and amortization[5]	4.7 X	4.4 X	5.1 X
Income from continuing operations before financing, taxes, depreciation and amortization[6]	4.7 X	4.3 X	4.3 X
Cash flow to interest bearing debt (%)[7]	22.7	22.8	23.3
Credit ratings[8]			
Standard & Poor's			
Long-term debt	BBB+	BBB+	BBB+
Preferred shares of subsidiary companies	P-2 (Low)	P-2 (Low)	P-2 (Low)
Dominion Bond Rating Service's			
Short-term debt	R-1 (low)	R-1 (low)	R-1 (low)
Long-term debt	A (low)	A (low)	A (low)
Preferred shares of subsidiary companies	Pfd-2 (low) / Pfd-3 (high)	Pfd-2 (low)	Pfd-2 (low)

(1) Cash flow from operations and ratios in this table are non-GAAP financial measures that do not have any standardized meaning prescribed by GAAP and are unlikely to be comparable to similar statistics published by other companies. They are presented since they are commonly referred to by debt holders and other interested parties in evaluating the Company's financial position and in assessing its credit worthiness. See "Non-GAAP Measures" for a reconciliation of cash flow from operations. The ratios are explained in the following notes.

(2) Debt to equity is expressed as a ratio of debt as a percentage of total capital to equity as a percentage of total capital. Debt is the sum of short-term debt and long-term debt (including the current portion). Equity is the sum of non-controlling interests and shareholder's equity. Total capital is the sum of debt and equity.

(3) Revenue and foreign exchange gains less energy purchases, fuel, operations, maintenance and administration, franchise fee, property taxes and other taxes and depreciation, amortization and asset retirement accretion, for continuing and discontinued operations, divided by interest on long-term debt and capital lease obligation for continuing and discontinued operations.

(4) Revenue and foreign exchange gains less energy purchases, fuel, operations, maintenance and administration, franchise fee, property taxes and other taxes and depreciation, amortization and asset retirement accretion, for continuing operations, divided by interest on long-term debt and capital lease obligation for continuing operations.

(5) Revenue and foreign exchange gains less energy purchases, fuel, operations, maintenance and administration and franchise fee, property taxes and other taxes, for continuing and discontinued operations, divided by interest on long-term debt and capital lease obligation for continuing and discontinued operations.

(6) Revenue and foreign exchange gains less energy purchases, fuel, operations, maintenance and administration and franchise fee, property taxes and other taxes, for continuing operations divided by interest on long-term debt and capital lease obligation for continuing operations.

(7) Cash flow to interest bearing debt (expressed as a percentage) is cash flow from operations divided by short-term debt plus long-term debt (including the current portion).

(8) Rating agencies have disclosed that all current ratings are stable.

Generally, our external capital is raised at the corporate level and invested in the operating business units. However, some of the businesses that we own jointly with parties unrelated to EPCOR, such as

Power LP and Joffre, have their own external financing. By centralizing our finance function we are able to access capital markets appropriate for our growth strategy and to minimize financing costs. Our external financing has consisted of borrowings under committed credit facilities, debentures payable to The City of Edmonton, public debentures, and preferred and common shares. Power LP's external financing has been raised through the issuance of partnership units and preferred shares, borrowings under lines of credit and long-term notes payable.

Financing

In May 2007, EPEL issued 5 million 4.85% cumulative, redeemable preferred shares for net proceeds of $121 million and Power LP issued limited partnership units for net proceeds of $102 million, as described under Significant Events. These financings were used to repay amounts outstanding under Power LP's bridge acquisition credit facilities which were incurred for Power LP's acquisition of Ventures. EPCOR, through wholly-owned subsidiaries purchased 1,228,681 limited partnership units to maintain its 30.6% interest in Power LP.

On August 15, 2007, a subsidiary of Power LP completed a private placement of senior unsecured notes for aggregate proceeds of $240 million (US$225 million), less issue costs of $1 million (US$1 million). The notes were issued in two tranches consisting of 10 and 12 year maturities. The $160 million (US$150 million) in 10-year notes have a coupon rate of 5.87% and the $80 million (US$75 million) in 12-year notes have a coupon rate of 5.97%. The combined carrying value of these notes declined to $223 million at December 31, 2007 due to a decrease in the U.S. dollar exchange rate.

On August 24, 2007, Power LP paid off its capital lease obligations for the Naval Station, North Island and Naval Training Centers for $72 million (US$68 million).

The proceeds from the private placement were used to repay the capital lease obligations and amounts initially borrowed as part of the Frederickson and Ventures acquisitions.

As of March 20, 2008 there were three common shares of the Company outstanding, all of which are owned by The City of Edmonton. EPCOR's dividend policy for these common shares has remained unchanged since 2000. Under the policy, the annual dividend is set at the greater of the previous year's dividend adjusted for the forecast change in the consumer price index, and 60% of the current year's earnings available to the common shareholder. This policy is subject to amendment in the event of a significant change in EPCOR's business or financial condition. Dividends for the year are generally established in the fall of the previous year based on forecast earnings. In accordance with the policy, the annual dividends for 2007 were $128 million (2006 - $125 million).

Power LP paid $91 million (2006 - $85 million) of distributions to the non-controlling unit holders.

EPCOR paid preferred share dividends, including those of EPEL, and related income taxes of $12 million (2006 - $17 million). The decrease from 2006 was due to the redemption of 6 million preferred shares at their stated redemption price of $150 million on June 30, 2006 and the redemption of 8 million preferred shares at par for $200 million effective September 30, 2007.

Operating activities

Cash flow from operating activities, which includes changes in non-cash working capital, decreased to $541 million in 2007 from $589 million in 2006. The decrease was primarily due to changes in non-cash working capital due to the timing of receipts and payments, reduced cash flow from the short-term tolling arrangements and the Battle River PPA, and net realized losses on forward foreign exchange and interest rate contracts. Cash flow from operating activities is anticipated to decline in 2008 from 2007 due to lower earnings. Cash requirements for working capital are expected to be substantially higher in 2008 than in 2007 due to the timing of payments related to accounts payable, and income taxes payable related primarily to the sale of an interest in the Battle River PSA.

2008 cash requirements

EPCOR's 2008 projected cash requirements include $800 million to $900 million for capital expenditures, $388 million for long-term debt repayments, $130 million for common dividends, and Power LP cash distributions as and when declared by the Board of Directors of its general partner.

The major project expenditures in 2008 will be on the Keephills 3, Clover Bar Energy Centre and DESS projects. The total cost of constructing the generation units at Clover Bar Energy Centre is expected to be approximately $283 million. The current estimate is higher than the original project estimate of $245 million due to unanticipated scope and cost increases which the Company is actively attempting to mitigate. The project remains viable and is expected to be within the range of the project economics we originally contemplated.

On January 25, 2007, we announced that based on the status of required local and provincial approvals, we would re-examine the project design and schedule of the Kingsbridge II project and terminate arrangements with certain suppliers. At that time we estimated that our project cash commitment, which was under review, would be approximately $300 million. The Company continues to work through the regulatory process with respect to this project.

If total cash requirements remain as planned, the sources of capital will be from cash on hand, operating cash flows, the scheduled sale of a further 10% interest in the Battle River PSA, existing credit facilities, new public debt borrowings, and public equity markets (Power LP). The Company does not expect that the funds invested in ABCP will impede the Company's ability to fulfill its capital requirements for 2008. However, the collapse of the ABCP market is illustrative of the broader tightening of credit markets and has resulted in reduced debt market liquidity and widening credit spreads. This could cause an increase in rates or a reduced market for new borrowings by the Company.

At December 31, 2007 the Company's bank lines of credit were as follows:

($ millions) December 31,	2007	2006	2007	2006
	EPCOR		Power LP	
Bank lines of credit – committed	$ 1,200	$ 1,200	$ 300	$ 468
Bank lines of credit – uncommitted	45	25	20	20
	1,245	1,225	320	488
Outstanding loans	(293)	-	-	(420)
Letters of credit outstanding	(357)	(236)	-	(12)
Bank lines of credit available	$ 595	$ 989	$ 320	$ 56

Committed bank lines are used principally for the purpose of providing capital and letters of credit. Letters of credit are issued to meet conditions of certain debt and service agreements, and to satisfy legislated reclamation requirements. The committed bank lines also back the Company's commercial paper program which has an authorized capacity of $500 million, of which $138 million was outstanding at December 31, 2007 (2006 - $nil).

On January 31, 2008, the Company completed a $200 million public offering of unsecured medium-term note debentures with a coupon rate of 5.8% and maturity date of January 31, 2018. Net proceeds from the offering will be used to repay EPCOR's commercial paper indebtedness and for general corporate purposes.

Credit ratings

In February 2008, Standard & Poor's reaffirmed EPCOR's credit rating for long-term debt at BBB+. DBRS Limited's rating also remained unchanged at A (low). The significant increase in debt and interest expense to fund capital expenditures planned for 2008 will weaken certain credit rating ratios but are not expected to result in ratings action. A ratings downgrade for EPCOR would result in higher interest costs on new borrowings and reduce the availability of sources of investment capital.

CONTRACTUAL OBLIGATIONS

$ millions	Payments due by period					
	2008	2009	2010	2011	2012 and thereafter	Total
Acquired PPA obligations[1]	$ 149	$116	$ 89	$ 88	$1,041	$1,483
Capital projects[2]	513	338	119	37	27	1,034
Energy purchase/transportation contracts[3] [4]	66	73	72	70	305	586
Asset retirement obligations	16	16	13	9	318	372
Long-term debt	388	26	221	215	1,305	2,155
Interest on long-term debt	178	160	137	117	1,008	1,600
Short-term debt	138	-	-	-	-	138
Operating leases	3	3	3	3	216	228
Operating and maintenance contracts[5]	28	27	28	29	201	313
Other purchase obligations	5	2	1	1	11	20
Total contractual obligations	$1,484	$761	$683	$569	$4,432	$7,929

(1) EPCOR'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) EPCOR's obligations for capital projects include Keephills 3, Clover Bar Energy Centre, EL Smith upgrade, DESS, and water treatment plants for the City of Wetaskiwin and the towns of Chestermere and Taber. EPCOR's obligation to construct the Kingsbridge II wind-power generation facility is not included as the project design and schedule are being re-examined.

(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 dates ranging from 2010 to 2016 with built-in escalators.

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

(5) Operating and maintenance contracts are based on fixed fees escalated annually by inflation and have expiry terms ranging from 2008 to 2018.

In the normal course of business, EPCOR provides financial support and performance assurances, including guarantees, letters of credit and surety bonds, to third parties in respect of its subsidiaries. The liabilities associated with these underlying subsidiary obligations are included in the consolidated balance sheet. In connection with the sale of Alberta mass-market competitive contracts to AESLP, effective February 1, 2005, EPCOR made arrangements to provide AESLP's prudential obligations with AESO and Alberta's wire service providers and gas distributors. On December 31, 2007, prudential obligations posted under this arrangement, in the form of letters of credit and guarantees, were $27 million (2006 - $36 million).

EPCOR is legally required to remove its power generation facilities and Genesee coal mine at the end of their useful lives and restore the plants and mine sites to their original condition. The Company estimates that the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $372 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2008 and 2090. The majority of the payments to settle the obligations are expected to occur between 2027 and 2064 for the power generation plants, and between 2008 and 2012 for sections of the Genesee coal mine**.**

As part of a 2003 disposition, EPCOR agreed to indemnify certain liabilities of UE Waterheater Operating Trust (the Trust) until 2010 primarily consisting of potential tax liabilities that could arise relating to operations of the water heater rental business prior to the sale by EPCOR to the Trust. Any known liabilities associated with this indemnification are reflected on the balance sheet at December 31, 2007 and it is uncertain what, if any, additional amounts may be incurred in the future.

The June 2006 sale of the initial 55% interest in the Battle River PSA was completed through a series of transactions. Before the sale, we owned approximately 70% of the PSA. To facilitate the eventual sale of a 100% interest to ENMAX Corporation, we acquired the remaining 30% interest in the PSA from non-EPCOR syndicate members for cash and an ownership interest in the Company's Sundance Power Syndicate Agreement (Sundance Swap). As part of the agreement for the Sundance Swap, we committed to providing interest-free notes of approximately $19 million to the counterparties to fund any income tax liabilities that they incur for the dispositions of their interests in the Battle River PSA. At December 31, 2007, the Company had advanced approximately $13 million.

In December 2007, the Company announced that it had entered into a 20-year lease for space in a new office tower for its headquarters in downtown Edmonton. The lease will commence January 1, 2012 or earlier and the existing lease for Edmonton offices will expire at the end of 2011.

There were no other material guarantee obligations outstanding in respect of third parties and no significant liquidity risks with respect to the Company's financial instruments at December 31, 2007.

OUTLOOK

In 2007, we focused on operational excellence, execution of development projects and integration of Ventures. Our strategy remains to grow our water and power business with a good diversity of asset types and geographic regions. In 2008, we will focus on maintaining the Company's income growth with increased capital expenditures and business development. The EL Smith upgrade and the DESS project are expected to be completed in 2008. Construction is expected to continue throughout 2008 on Keephills 3 and Clover Bar Energy Centre.

Our business development activity will concentrate on water and power prospects. Public interest in water is increasing and water pricing is starting to reflect its growing scarcity. As demand continues to increase, we anticipate increased requirements for better water management practices including watershed management and conservation. In North America, there are significant water infrastructure upgrade requirements which we believe will provide us with growth opportunities. Although there has not been a major shift to water markets opening to private development, there has been some progress in public-private partnerships. We are a solution provider who can maximize the efficient, effective and environmentally responsible use of this resource.

Environmental policy development and discussion are becoming more intense across North America and around the world. Recently, Canadian federal and provincial governments have taken strong environmental and fiscal positions. In addition, the public is not appropriately informed about the present state of technology and the valuable continuing role to be played by coal. Environmental policy remains uncertain and regional initiatives may be out of step with federal policy development.

New stringent emission standards will evolve and could have a material impact on EPCOR's operations. EPCOR is supportive of initiatives to decrease emissions, but this needs to be done in a thoughtful and prudent manner. This situation requires us to continue to be vigilant in discussing policy initiatives with legislators to ensure they are fair and do not result in impractical or damaging policies. We plan to be actively engaged in raising our public profile as an environmentally responsible water and power provider.

Our strategy of improving our existing power and water operations continues which means extracting the maximum efficiency and effectiveness from our existing operations.

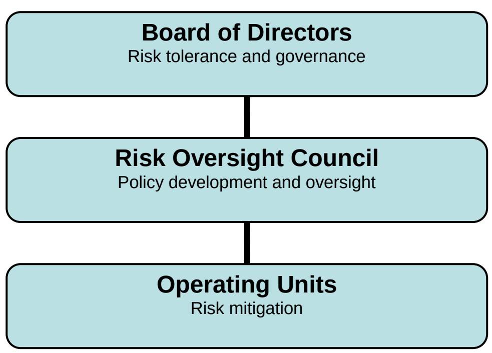
Our earnings are expected to be lower in 2008 and factors that will impact 2008 include:

- No items similar to the tax benefit of the Energy Services reorganization in 2007.
- Two major outages are planned at the Genesee site in 2008 for scheduled equipment repairs and maintenance whereas one outage occurred in 2007.
- Increased business development activity emphasizing water and environmentally responsible power.
- Higher operating costs primarily due to higher labour rates.

In addition, fair value changes can cause significant positive or negative income volatility.

RISK MANAGEMENT

Approach to risk management



Our approach to risk management is to identify, monitor and manage the key controllable risks facing the Company. Risk management includes the controls and procedures implemented to reduce controllable risks to acceptable levels and the identification of the appropriate management actions in the case of events occurring outside of management's control. Acceptable levels of risk for EPCOR are established by the Board of Directors, representing the shareholder, and are embodied in the decisions and corporate policies associated with risk. Risk management is generally carried out at three levels. Firstly, general oversight, policy review and recommendation, and reviews of risk compliance are provided by the Risk Oversight Council, a senior executive group including the Vice President, Risk Management. Secondly, the Vice President, Risk Management is generally 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 operational business units and shared service units are responsible for carrying out the risk management and mitigation activities associated with the risks in their respective operations. These risk management activities are integral aspects of the business units' and shared service units' operations. We believe that risk management is a key component of the Company's culture and we have put into place cost-effective risk management practices. At the same time, we view risk management as an ongoing process and continually review our risks and look for ways to enhance our risk management processes.

Electricity price and volume risk

We buy and sell electricity in the wholesale markets of Alberta, Ontario, and the U.S. Such exchanges are settled at the spot market prices of the respective markets. We currently use purchase and sale arrangements including CfDs and firm price physical contracts for periods of varying duration to manage our exposure to spot price variability within specified risk limits. Due to limited market liquidity and the varying shape of electricity consumption during peak usage hours compared with off-peak usage hours, it is not possible to hedge all positions every hour. We balance our electricity position within the limits of our policies and generally trade in electricity to reduce the Company's exposure to changes in electricity prices or to match physical and financial obligations. A limited portion of our trading is directed at optimizing our electricity position.

When aggregate customer electricity consumption (load shape) changes unexpectedly, EPCOR is exposed to electricity price risk. Load shape refers to the different pattern of consumption for peak hours and off-peak hours. Consumption is higher during peak hours when people and organizations are active, than during off-peak hours. We purchase blocks of electricity in advance of consumption to minimize exposure to extreme price fluctuations, especially during higher priced peak hour periods. In order to do this, we rely on historical aggregate consumption data 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, we are exposed to the prevailing market prices because we must either buy electricity if we have less than we need (short) or sell electricity if we have more than we need (long). Exposures can be exacerbated by other events such as unexpected generation plant outages and unusual weather patterns.

Electricity sales associated with EPCOR's Genesee units 1 and 2 are governed by the terms of the associated PPAs. 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. Our other plants, such as Brown Lake, Miller Creek, and Kingsbridge I operate under long-term commercial contracts with credit worthy counterparties. Our 40% interest in Joffre is governed by a long-term commercial contract. However, its operations are subject to market price variability as there are provisions in the contract that require the facility to run to provide steam to the host facility, irrespective of market prices. Although our 50% interest in Genesee 3 is not covered by a long-term commercial contract, it is a base-loaded coal-fired generating unit with a relatively low variable cost and it will generally run when it is available. It is subject to spot price exposure when those prices are below its price for corresponding variable costs or the unit suffers an unplanned outage. Since its commissioning, the occasions when Alberta electricity prices have been below Genesee 3's variable cost have been very limited and the plant has operated above our expectations.

Electricity price and volume risks for Power LP, including Ventures' plants acquired in November

2006, are lower than they would be in a merchant environment since each of the facilities operates under long-term power sales contracts with investment-grade power and steam buyers.

In order to stabilize future cash flows, we will seek to re-contract existing generation plants under new or extended contracts and acquire new plants that meet our investment criteria. Although commercial contracts provide better electricity price and volume protection than if the plant operations were completely subject to spot market risk, the contract provisions must be met and the Company can incur charges in the event of unplanned outages or variations from the contract performance benchmarks.

Natural gas price and volume risk

Price risk associated with natural gas purchased for our natural gas-fired generation plants operating under commercial contracts is mitigated by the provisions of the contracts which generally require the contract power buyer to pay the generator a market indexed price or buy the gas outright on behalf of the plant. Natural gas price risk associated with Joffre is partly flowed through to its electricity sale prices as they depend on the natural gas price. For Power LP's natural gas-fired plants, the natural gas price risks have been minimized by executing fixed price long-term contracts for a significant portion of the supply of natural gas or through the use of tolling agreements. However, certain Power LP plants are at risk for the fuel supply after the term of the fixed price contract if it expires before the termination of the PPA. For example, for its Tunis Plant, Power LP will be exposed to commodity price risk on its natural gas purchases commencing with the expiry of its natural gas contract in 2010 until the expiry of the PPA in 2014, unless Power LP is able to secure another fixed-price natural gas supply contract for that period. We will attempt to bridge these gaps by securing new natural gas contracts.

For our retail and wholesale natural gas contracts, we balance our exposure by purchasing natural gas back-to-back with our sales contracts to the fullest extent possible. That is, we normally purchase only enough physical natural gas delivery in advance to satisfy the natural gas load represented by expected volumes from signed contracts. Natural gas exposures are managed to the specific limits established by our risk management policies.

The initial term of a block of retail natural gas contracts that we acquired in 2000 expired in late 2004. The customers under these contracts had an option to renew at the original contracted price and approximately 56% did so with terms expiring by the end of 2009. Due to the relatively low embedded contract price, EPCOR will experience losses on servicing these contracts which are estimated to be up to $5 million for 2008 and 2009, depending on future natural gas prices. As we are no longer active in the retail natural gas market, we will continue to seek opportunities to exit from these contracts.

Commodity risk measures and limits

Our tolerance for energy commodity price and volume risk is based on our assessment of the trade-off between risk and return for the underlying commodity. The risk tolerance of our consolidated energy commodity portfolio is established by total exposure limits as set out in policy and approved by the Board of Directors.

We use Value-at-Risk (VaR) as the basic component to measure the risk in our energy commodity portfolio. VaR is the maximum expected loss over a given period of time at a given level of confidence. Our VaR is calculated at a 95% statistical confidence level over a holding period of 20 business days. In other words, over the 20-day period commencing with the point in time that the VaR is measured, there is a 1 in 20 likelihood that the fair value of our commodity portfolio could change by an amount in excess of the VaR amount. The VaR calculation incorporates positions, forward prices, price volatilities and correlations as major input variables. As VaR is not a perfect measure of risk, we apply a factor to the calculated VaR amount to attempt to capture unaccounted for exposures. The resulting measure is referred to as the total exposure of the portfolio. EPCOR's one year energy commodities total exposure, when considering the portfolio on a net basis, as at December 31, 2007 was $8 million (2006 - $20 million).

To supplement the total exposure estimates, we use stress-testing and scenario analysis on the electricity and natural gas portfolio by applying plausible but unlikely adverse market conditions and movements. This testing is used to determine the resulting financial effects on the portfolio in relation to the Company's total exposure limits. We have also adopted a series of operational limits for our energy trading operations, including position limits, transaction limits and stop loss limits. Key risk measures in relation to the applicable limits are reported daily to Risk Oversight Council and quarterly to the Board of Directors.

Operational risk

The ability of EPCOR's power plants to generate the expected amount of electricity that will be sold under contract or to the applicable market has a significant impact on the revenues of the Company. If a power plant delivers less than the required quantities of electricity in a given month, revenue may be insufficient to cover contractual or financial obligations.

Our plant operations are susceptible to outages due to equipment failure, which could make plants unavailable to provide service. This is also true for the generation units associated with the acquired PPAs. Such 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. We have a very strong record of availability, as measured against our peers by the Canadian Electricity Association. In addition, the penalty provisions within the PPAs provide appropriate incentives to owners to keep the plants well maintained and operational. The terms of the PPAs also provide force majeure protection for high-impact low probability events including major equipment failures. Our maintenance practices are augmented by the maintenance of an inventory of strategic spare parts, which can reduce down time considerably in the event of failure. Finally, we have secured appropriate business interruption insurance to reduce the impact of prolonged outages caused by insured events at our generation plants and at the plants supporting our acquired PPAs.

Operational risk in Distribution and Transmission, and Water Services is also managed through sound maintenance and safety practices. In addition, Water Services performs continuous and rigorous quality control testing of water purification to ensure adequate water treatment consistent with government and industry standards. The ability of the water treatment plants to maintain adequate treatment and testing of water on a continuous basis is essential to ensure that the prescribed requirements under regulation or conventional industry standards are met. Failure to properly maintain fully functioning treatment and measurement systems could result in regulatory fines, lost revenue or potential lawsuits.

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 we hold a 50% interest. The price of coal is based on a cost-of-service model with annual updates to inflation, interest rate and capital budget parameters and is, therefore, not subject to coal market price volatility. EPCOR and the Genesee Coal Mine joint venture maintain coal inventories which are available as fuel supply in the event that the coal mine equipment and operations suffer significant disruption.

Power LP's coal-fired power plants (Roxboro and Southport) purchase coal and tire-derived 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 the coal-fired power plants if alternative transportation cannot be arranged in a timely manner.

The level of waste heat fuel at Power LP's Ontario plants, provided by TransCanada Corporation's adjacent compressor stations, is dependent upon the amount of natural gas throughput on the pipeline and the output of the compressor stations. In addition, the availability of waste heat gases is dependent upon the compressor stations remaining in use and their ability to supply the waste heat gases.

Performance of our hydroelectric facilities is dependent upon the availability of water. Variances in water flows are caused by uncontrollable weather related factors affecting precipitation and can 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 an impact on revenues from the associated plants.

We manage the wood waste fuel risk at Power LP's biomass and wood waste plants through contracts with a number of wood waste suppliers, and a new two year wood supply agreement was negotiated in August 2007.

We use several key computer application systems to support our various operations such as electricity and water distribution network control systems, electricity and water plant control systems and electricity settlement and billing systems. We take measures to reduce the risk of malicious corruption or failure of these systems and the hardware and network infrastructure on which they operate, as well as electronic theft of data.

We maintain a Compliance and Ethics Policy which includes an Accounting and Auditing Complaint Procedures Policy which provides for confidential disclosure of any wrong-doing relating to accounting, reporting and auditing matters.

Environment, health and safety risk

Environment

There are a variety of significant environmental risks associated with each of our power and water operations such as air emissions, water use, wastewater discharges, waste, land use and landfill. We manage these risks by incorporating the environment in our strategy, policies, processes and procedures.

EPCOR's strategy includes a commitment to environmental performance on existing and new facilities, renewable energy and investment in the development of coal gasification with carbon capture and storage. In addition, EPCOR's environmental policy commits the Company and all of its employees to environmental compliance and stewardship.

Each plant and facility has an environmental management system which meets the ISO 14001 standard. These systems encompass the identification of the scope, objectives, training and stewardship of our environmental responsibility. Each plant and facility is also subject to environmental audits to ensure compliance with all regulations.

Our operations, technical support and environment departments work on technology solutions to emerging environmental issues such as mercury emission mitigation. We are active in the development of the CO2 offset market by designing protocols, developing projects that will qualify for offsets and trading offsets.

EPCOR complies, in all material respects, with federal, provincial, state and local environmental legislation and guidelines with respect to its electricity operations. EPCOR's generation business is a significant emitter of carbon dioxide (a greenhouse gas), nitrogen oxides and sulphur dioxide. Compliance with future environmental legislation may require significant capital and operating expenditures and failure to comply could result in fines and penalties or the regulator could force the curtailment of operations.

Canada

On April 26, 2007, the Canadian Environment Minister proposed a new regulatory framework to reduce greenhouse gas emissions and air pollution in Canada and then released further information on the proposed regulatory framework on March 10, 2008. If adopted, the proposed framework would require a 20% absolute reduction in greenhouse gases from 2006 levels by 2020 and a 50% reduction in air pollution by 2015. Carbon dioxide, nitrogen oxide and sulphur dioxide emissions are all targeted for reduction under the proposed legislation. Some of the other key provisions of the proposed framework are:

- The cleaner fuel standard for coal-fired generation would be supercritical pulverized coal technology (such as Genesee 3 and Keephills 3) and the cleaner fuel standard for natural gas-fired generation would be natural gas combined cycle technology;
- The framework would apply to each generating facility with generating capacity greater than 10 MW (which would include most of EPCOR's generating units);
- Corporations (such as EPCOR), that own existing generating facilities would be required to reduce the intensity of the emissions of their entire fleets by 18%, starting in 2010 and increasing by 2% per year thereafter;
- New generating facilities placed into production after 2004 and before 2012 (such as Keephills 3), (i) would be allowed a 3-year commissioning period during which no intensity targets would apply, (ii) must comply with the cleaner fuel standard from and after commissioning, and (iii) must reduce their emissions by 2% per year after expiry of the commissioning period;
- Greenhouse gas emitters (such as EPCOR), would be able to obtain credits for compliance by making contributions toward a fund to support the development of emission-reducing

EPCOR estimates that its costs of compliance with this framework could be range from $8 million to $12 million for 2010, escalating proportionately with the increasing emission reduction targets after 2010. This estimate is based on EPCOR's current fleet of generation assets and the costs of contributions to the technology fund as outlined in the proposed framework. Readers are cautioned that there are a number of uncertainties associated with this estimate including, but not limited to: whether the regulations that are enacted in the future reflect the proposed framework as described by the government on March 10, 2008; the extent to which future costs will be recoverable from customers; the future composition of EPCOR's fleet of generation assets; the future production of electricity from EPCOR's generation assets; the extent and timing of the development of a carbon offset market; whether economically feasible emission–reducing technology emerges; the market price for carbon offset credits and other measures that the Company might undertake to reduce its emissions.

We participate in the Clean Air Strategic Alliance which has recommended to the Alberta government a framework on nitrogen oxide, sulphur dioxide, mercury and particulate emissions, for both natural gas-fired and coal-fired generation plants. EPCOR will participate in tests and install equipment over the next 3 years to meet Alberta requirements to reduce mercury emissions by 70% by 2011.

Consistent with our strategy to anticipate and comply with environmental legislation, EPCOR is participating in a $33 million research project to undertake a front-end engineering design study of a clean coal project. The Government of Canada announced in October 2007 that it will partner with us, the Alberta Energy Research Institute (AERI) and the Clean Coal Power Coalition in this project. The Government of Canada is investing $11 million in the project through ecoENERGY Technology, and each of EPCOR and AERI will contribute the same amount. EPCOR will also contribute use of the Genesee site for the study. The work is scheduled for completion in 2009, and if subsequent investment and construction decisions go as planned, a 500 MW generating station using the new technology could be in operation in Alberta as early as 2015.

Effective July 1, 2007, EPCOR is subject to the Alberta Government's new Specified Gas Emitters Regulation. The regulation is applicable to all facilities in Alberta that produce over 100,000 tonnes of carbon dioxide equivalent (CO2E or greenhouse gas) per year. Accordingly, EPCOR's Genesee generating units 1, 2 and 3 and the generating units subject to PPAs in which EPCOR holds interests (i.e. Sundance 5 and 6 and Battle River) are subject to the regulation. The regulation imposes a CO2E intensity reduction of 12% from the average CO2E emissions intensity for the 2003 to 2005 period. Under the regulation entities that cannot meet the reduction target may either contribute cash to an Alberta technology fund at $15 per tonne of excess emissions intensity or invest in Alberta based projects that reduce or offset emissions on their behalf. While compliance is required effective July 1, 2007, the first reporting deadline, which includes the submission of offsets, is March 31, 2008.

The costs associated with compliance with the regulation for Genesee 1 and 2 generating units are recoverable from the PPA holder under the terms of the PPA. These costs amounted to $4 million in 2007 and are estimated to be approximately $11 million per year in the future. EPCOR's Genesee 3 unit is considered a new unit under the regulation and will receive a three-year grace period, after which its compliance obligation will be phased in over 5 years, starting at a 2% intensity reduction and increasing to 12% by the end of the 5 years. The estimated cost of EPCOR's share of the compliance cost after the grace and phase-in periods is approximately $3 million per year. EPCOR's share of the compliance costs for Sundance 5 & 6 is estimated to be approximately $5 million per year. The cost of compliance for our interest in the Battle River PPA is estimated to be approximately $2 million for each of 2008 and 2009. These cost estimates assume that no offsets will be used to comply with the regulation. We will likely use offsets which may reduce this estimated cost of compliance but their availability and cost are not yet determinable. In 2007, EPCOR recorded $3 million for the cost associated with this regulation.

In September, 2007 there was an incident at our Miller Creek plant where a series of mechanical and operator errors caused a low water condition to occur in the creek on which the plant is located. B.C. Environment is investigating EPCOR's conduct at Miller Creek. Although the incident should not result in a material financial loss, we are taking the incident very seriously and taking steps to ensure that we prevent an episode like this from recurring.

Our water operations comply in all material respects with federal, provincial, and local environmental legislation and guidelines. These operations are controlled through stringent water treatment standards and controls covering the quality of treated water and the number, frequency and form of water quality testing, as well as mandatory improvements to the water treatment process. We are actively involved in a watershed management program, which involves the protection and management of our Edmonton water source from impurities such as soil particles, excess nutrients, fertilizers, microbiological contaminants and organic materials. Activities undertaken include river water quality monitoring, forming stakeholder partnerships to work on watershed issues, and acting as a resource and leader on quality issues of the North Saskatchewan River Basin.

United States

We continually assess the potential impact on Power LP assets of future legislation and regulatory requirements for certain air emissions under the United States' Clean Air Act (US CAA). The US CAA Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) will affect the Roxboro and Southport facilities in North Carolina beginning in 2009. The North Carolina plants were pulled into the CAIR program, but did not receive nitrogen oxide and sulphur dioxide allocations. The costs associated with purchasing the required offset allocations are projected at approximately $1.5 million per year. Engineering and operating solutions are being pursued which will combine operating methods such as alteration of the fuel mix, and emissions controls to reduce the annual cost.

The North Carolina plants are classified as low emitters of mercury as they emit less than 9 pounds per year at each plant. The plants will be required to install mercury emission monitoring equipment in order to comply with CAMR. The cost of the monitoring equipment is estimated at less than $0.2 million.

The Kenilworth facility in New Jersey and the Castleton facility in New York are potentially affected by the Regional Greenhouse Gas Initiative applicable in seven New England states. The regulations are implemented on a state-by-state basis and we are monitoring the states' proposals and evaluating their impact on Power LP operations.

California has recently enacted stringent limits on greenhouse gases and is currently developing regulations to implement the program. We are monitoring the state's progress and the features of the program to assess the financial and operational implications on Power LP's California plants.

Compliance with future environmental legislation may require material capital and operating expenditures and failure to comply could result in fines and penalties or the regulator could force the curtailment of operations. There are significant uncertainties associated with the current legislative proposals including implementation details, their impact on current licenses and permits, and how compliance costs might be recovered through prices or shared among emitters, customers and stakeholders. Accordingly, it is not possible to provide meaningful estimates of the costs of complying with the proposed legislation or the net financial impact on EPCOR.

Health and safety

We manage our health and safety risks through company-wide health and safety management processes. We also monitor our health and safety performance against recognized industry and internal performance measures.

Our operations are subject to the risks of a widespread influenza outbreak or other pandemic illness. We have developed plans to respond to a potential pandemic influenza to help maintain a sufficient healthy workforce and enable the Company to deliver reliable power and water to customers in such an event.

Government and regulatory risk

EPCOR is subject to risks associated with changes in federal, provincial, state, local or common law, regulations and permitting requirements in Canada and the United States. It is not possible to predict changes in laws or regulations that could impact the Company's operations, income tax status or ability to renew permits as required.

Under the Settlement System Code of the *Electric Utilities Act* (Alberta*),* a retailer must rely on load settlement agents to provide customer consumption data to be used in computing its customers' bills. Under the *Alberta Regulated Default Supply Regulation*, regulated rate providers may not collect from customers an amount undercharged due to a billing error if the error occurred more than 12 months before the date of the revised billing.

Effective January 1, 2008 the Alberta Energy and Utilities Board (AEUB) was separated into two boards, the AUC and the Energy Resources Conservation Board, with new regulations. The intent was to bring more resources to both electricity and oil sands issues. The new regulations provide the AUC with authority to impose harsher penalties for noncompliance. Under these new rules, potential fines for serious infractions, such as exercising market power, could be as high as $3 million per day. EPCOR believes that its governance and monitoring policies reduce the risk of EPCOR incurring such fines.

In 2006, the AUC (formerly AEUB) set final rates for the 2005 and 2006 Distribution and Transmission tariffs and RRT non-energy charges. In 2007 EPCOR filed its 2007 – 2009 tariff application for its RRT non-energy charges. EPCOR filed its Distribution and Transmission 2007 – 2009 tariff application at the end of January 2008. These application processes have risks customarily associated with rate-regulated tariff filings.

The AUC sets rates intended to permit the regulated Distribution and Transmission business to recover estimated costs of providing service and a fair rate of return on investment in distribution and transmission. In its current RRT non-energy tariff application, the Company has applied for a return margin (a percentage of revenue), rather than a traditional return on rate base. Our ability to recover the actual costs of providing service and to earn a fair return is dependent upon achieving the forecasts established in the rate-setting process.

On June 8, 2005, the Government of Alberta announced a new 5-year RRO for residential, farm and small commercial Alberta electricity consumers. The new RRO replaced the Regulated Rate Tariff which expired on June 30, 2006 and regulates our charges to these customers for energy. The RRO became the default option for consumers in the aforementioned customer segments who have not entered into contracts with an electricity retailer. Commencing on July 1, 2006, the new RRO uses a combination of long-term and monthly forward hedges, with an increasing percentage of monthly forward hedges over the 5-year transition period. At the end of the transition period in 2010, the new RRO is intended to be similar to the design of the current Alberta natural gas default rate, which is based on monthly forward prices. As this electricity pricing model results in increasing volatility in prices to our customers over the transition period, it may impact our volume of electricity sales, as well as electricity margins. To date the financial impact to EPCOR has been insignificant.

EPCOR's water treatment and distribution services to customers within The City of Edmonton are rate-regulated by The City of Edmonton Council pursuant to a performance based rates bylaw. Rates approved under this bylaw are intended to allow the Company to recover its operating costs and earn a return on equity, as well as provide an incentive to manage cost increases below inflation. If the performance targets outlined in the bylaw are achieved, water rates are increased by the change in the rate of inflation less an efficiency factor. The City of Edmonton Council approved a renewal of the PBR bylaw on July 4, 2006 for the 5-year period commencing April 1, 2007. Our ability to fully recover operating and capital costs and to earn a fair return is dependent upon achieving the performance targets prescribed in the Bylaw, maintaining cost increases below inflation and managing operational risks.

Rates for water sales to regional water commissions that supply water to communities surrounding Edmonton are regulated by the AUC on a complaints-only basis, whereby such communities may apply to the AUC to resolve disputes related to rates, tolls or charges determined by the Company. EPCOR sets the rates it charges to these regional water commissions to recover related operating and capital costs plus a reasonable rate of return. Actual operating and capital costs associated with the provision of water to the commissions and a fair return on rate-base, are recovered in accordance with a full cost-of-service method which has been approved by the AUC.

Income Tax Risk

On September 21, 2007, the U.S. and Canada signed the fifth protocol to the U.S. - Canada Income Tax Treaty (Treaty), which contains extensive changes to the current Treaty. The Treaty included the addition of a treaty denial provision applicable to payments obtained from or through certain hybrid entities. A hybrid entity in this context means one with different tax treatments under different tax jurisdictions, which is the case for Power LP. The Treaty has not yet been ratified and the treaty denial provision will not be effective earlier than 2010. EPCOR continues to evaluate the potential impact, if any, that the treaty denial provisions will have but management expects to be able to address the denial provisions without realizing any materially adverse tax consequences.

Canadian tax legislation, (SIFT Legislation) related to specified investment flow-through entities (SIFTs) included in Bill C-52 was enacted in 2007 and will result in changes to how certain publicly traded trusts and partnerships, including Power LP, are taxed. It is expected that under this legislation Power LP will become taxable commencing in 2011 as long as it does not exceed the Canadian Department of Finance's normal growth guidelines by issuing greater than $1.7 billion of new equity before 2011. All other things being equal, the SIFT Legislation will likely result in a reduction of cash available for distribution by Power LP commencing after 2010.

Project risk

Our construction and development of generation, electric transmission and distribution, and water treatment facilities and acquisition activities are subject to various engineering, construction, stakeholder, government and environmental risks, many of which are beyond our control. Furthermore, rapid cost escalation has occurred in a number of regions in which we operate. These risks can translate into performance issues, delays and cost overruns. We attempt 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.

Supply risk of Alberta PPAs

EPCOR holds interests in acquired PPAs, which entitle the Company to its proportionate interest in the electricity produced from specific generating units up to their committed capacity. In most cases when plant capability falls below committed capacity, we are entitled to receive our relative portion of the availability payments from the plant owners based on the 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 the PPAs, preventing the PPA owners from fulfilling their obligations under the PPAs, could have a material negative impact on our ability to generate revenue. In such circumstances, we may be required to replace unavailable generation output with electricity at prevailing market rates, while being relieved of the obligation to pay the unit capacity fee. Depending on market liquidity, the prices could be significantly higher than the prices inherent in the PPA, thus increasing the cost of our energy purchases.

Credit risk

Credit risk is the possible financial loss associated with the ability of counterparties to satisfy their contractual obligations to EPCOR, including payment and performance. We manage credit risk and limit exposures through our credit policies and procedures. These include an established credit review process, specific terms and limits, credit diversification, daily monitoring of wholesale exposures against credit limits, appropriate allowance provisioning and use of credit mitigation strategies, including collateral arrangements.

Wholesale credit risk

Exposure to credit risk for wholesale and 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 netting amounts if permitted by legally enforceable set-off rights.

Due to price volatilities of electricity and natural gas, the market value of individual credit exposures could exceed the credit limits granted to those counterparties. If the counterparty fails to perform its obligations EPCOR could incur a material loss. This could include, but is not limited to, the cost of replacing the obligation, a loss on amounts owed from the counterparty or a loss incurred on liability settlements.

EPCOR’s exposure to wholesale and trading counterparties is summarized below. Exposures represent 60 days of potential accounts receivable plus the fair value of the contracts.

December 31 ($ millions)	2007	2006
Wholesale (includes industrial end-use customers, trading and position management counterparties)		
Investment grade(1)	$117	$116
Below-investment grade(1)	19	14
Total	$136	$130

(1) Credit ratings are based on EPCOR's internal analyses which take into account the ratings of external credit rating agencies.

The year-over-year increase in the credit exposure of both investment grade and below-investment grade counterparties is primarily due to additional transactions with current counterparties.

RRT and default supply credit risk

Exposure to credit risk for residential and commercial customers under default power supply rates are generally limited to amounts due from the customers for electricity consumed but not yet paid for. As the electricity procurement for these customers has evolved to shorter terms, our exposure to losses for the purchase of electricity that is not consumed has been mitigated.

This portfolio is reasonably well diversified with no significant credit concentrations. Historically, credit losses in these customer segments have not been significant and depend in large measure on the strength of the economy and the ability of the customers to effectively manage their affairs through economic cycles and competitive pressures. Should economic or market conditions decline in the regions in which we provide service, we may experience additional credit losses in these segments. Although regulations allow for recovery of a percentage of unforecasted credit losses through a deferral account, EPCOR monitors credit risk for this portfolio at the gross exposure level.

EPCOR's exposure to RRT and default customer credit risk, which is primarily the risk of non-payment for electricity consumed by these end-use customers, is summarized below. Exposures represent a 60-day potential accounts receivable value for this portfolio.

December 31 ($ millions)	2007	2006
Unrated RRT and default supply customers(1)	$144	$151[2]

(1) Under the *Alberta Electric and Utilities Act*, EPCOR provides electricity supply in its service area to residential, irrigation and small commercial customers and those commercial and industrial customers in its service areas who have not chosen a competitive offer and consume electricity under default supply arrangements.

(2) December 31, 2006 value includes $141 million of accounts receivable and $10 million of fair value exposure.

In the RRT and default supply category, the year-over-year increase in exposure related to the 60-day potential accounts receivable from $141 million to $144 million was driven by higher electricity prices.

Power LP credit risk

The values above do not include EPCOR's exposure to credit risk derived from activities within Power LP. Power LP has exposure to credit risk associated with counterparty default under its power and steam sales contracts, energy supply agreements and foreign currency hedges. In the event of default by a counterparty, existing PPAs and steam purchase agreements may not be replaceable on similar terms as many of these agreements have favourable pricing relative to their current markets. Power LP‘s counterparty risk is managed by making appropriate credit assessments of counterparties, dealing with creditworthy counterparties, diversifying the risk using several counterparties and where appropriate and contractually allowed, requiring the counterparty to provide appropriate security.

Availability of people

Our ability to continuously operate and grow the business is dependent upon retaining and developing sufficient labour and management resources. As with most organizations, we are facing the demographic shift where a large number of employees is expected to commence retirement over the next few years. In addition, the market for labour and management, particularly in Alberta and British Columbia, is extremely competitive. Although a legislated forced arbitration for Alberta building trades in the third quarter eliminated the risk of a legal strike, general labour challenges remain as a risk to the timing and cost of our projects in the province. We believe that we employ good human resource practices and have been named a top 100 employer in Canada for 8 consecutive years. We continue to monitor developments and review our human resource strategies to ensure we have an adequate supply of labour and management.

Weather risk

Weather can have a significant impact on our operations. Temperature levels, seasonality and precipitation, within EPCOR’s markets and adjacent geographies, can affect the level of demand for electricity and natural gas, thus resulting in electricity and natural gas price and volume volatility. In addition, the level of precipitation affects the availability of our hydro generating units and impacts the cooling pond reservoir level at the Battle River generation plant, which in turn can impact the performance of our interest in the Battle River PPA.

Melting snow, freeze/thaw cycles and seasonal precipitation events in the North Saskatchewan River watershed affect the quality of water entering our water treatment plants and the resulting costs of purification. Weather variability and seasonality also impact the demand and supply of water.

Extreme weather can impact the physical operation of our facilities. Two of Power LP’s facilities are situated in North Carolina, a region susceptible to hurricanes.

Weather related financial instruments are available in the financial markets but we have not pursued them due to their limited coverage and relatively high cost. Financial exposures associated with extreme weather are managed through our insurance programs.

Foreign exchange risk

Fluctuations in the exchange rate between either the U.S. dollar or the Euro, and the Canadian dollar affect some of our revenues, capital costs, operating costs and cash flows, and could have an adverse impact our financial performance and condition.

The foreign exchange risk of anticipated U.S. dollar denominated cash flows from Power LP’s U.S. plants is managed through the use of forward foreign exchange contracts for periods of up to 7 years. At December 31, 2007, US$281 million (2006 - US$331 million) or approximately 83% (2006 – 70%) of these future cash flows were economically hedged for 2008 to 2013 (2006 – 2007 to 2013) at a weighted average exchange rate of 1.13 (2006 – 1.14).

In situations where EPCOR contracts to purchase large value parts for Generation and, Distribution and Transmission operations from suppliers outside of Canada, we generally fix the purchase price in Canadian dollars by contracting in Canadian dollars or using forward foreign exchange contracts.

Conflicts of interest

Certain conflicts of interest could arise as a result of EPCOR's relationship with The City of Edmonton, which is EPCOR's sole common shareholder and regulator for EPCOR's water utility rates in Edmonton.

In addition, certain conflicts of interest could arise as a result of EPCOR's relationship with Power LP. The Company is, through wholly-owned subsidiaries, Power LP's principal unitholder, 100% owner of the general partner, EPCOR Power Services Ltd. (GP), and through wholly-owned subsidiaries of the Company in both Canada and the U.S., manager of the assets and operations of Power LP.

Other conflicts of interest could arise as a result of Power LP's relationship with Primary Energy Recycling Corporation (PERC). Ventures, a wholly-owned subsidiary of Power LP, also has a 15.4% equity ownership of and provides management and administrative services to PERC, PERH and PERH's subsidiaries under a management agreement. PERC, through PERH and its subsidiaries, engages in activities similar to those of Power LP and Ventures. PERC owns the remaining 84.6% equity in PERH.

Certain senior officers of EPCOR are officers and directors of GP and Power LP's subsidiaries. The board of directors of the GP currently has eight members, four of whom are EPCOR elect directors and four of whom are independent directors within the meaning of applicable Canadian securities laws. The chairman of the board of directors of the GP is an executive officer of EPCOR and has a casting vote or second vote in the case of a tie vote at any meeting of the GP board of directors.

General economic conditions, business environment and other risks

The Company is exposed to potential recovery and fair value measurement uncertainty in respect of its investment in third party ABCP. See Asset-Backed Commercial Paper under Significant Events. The credit and liquidity issues that impacted the global economy in 2007 have resulted in credit markets being less readily accessible. In addition, Power LP's unit price is exposed to market volatility. These conditions pose a risk to the Company's plans for new project financing.

Transmission risk relates to blackouts or constraints on the system which result in curtailment of output at generation facilities or restrictions on the development of interconnections with new generation facilities. This risk is mitigated by the terms of our PPAs and long-term power contracts. We also manage our relationships with regulators and governments to ensure that appropriate transmission capability and technology is developed in a timely manner.

Fluctuations in interest rates, product supply and demand, market competition, risks associated with technology, EPCOR's ability to generate sufficient cash flow from operations to meet its current and future economic and business conditions, EPCOR's ability to access external sources of debt and equity capital, general economic and business conditions, EPCOR's ability to make capital investments and the amounts of capital investments, risks associated with existing and potential future lawsuits and other regulations, assessments and audits (including income tax) against EPCOR and its subsidiaries, political and economic conditions in the geographic regions in which EPCOR and its subsidiaries operate, difficulty in obtaining necessary regulatory approvals, a significant decline in EPCOR's reputation and such other risks and uncertainties described from time to time in EPCOR's reports and filings with the Canadian Securities authorities could materially adversely impact EPCOR's business, prospects, financial condition, results of operations or cash flows. Our ability to mitigate these risks is dependent upon management's ability to anticipate such risks and, where possible, to develop appropriate mitigation plans.

The following table outlines our estimated sensitivity to specific risk factors as at December 31, 2007. Each sensitivity factor 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 sensitivity factors will not be held constant but rather, will change at the same time as other factors are changing. In addition, these sensitivities are presented at December 31, 2007 and the degree of sensitivity to each factor will change as the Company's mix of assets and operations subject to these factors changes or the degree of commodity hedge coverage changes.

Factor ($ millions)	Change	Annual Cash Flow	Annual Net Income
Wholesale price of electricity – Alberta[1]	+ $5/MWh	+ 4	- 9
Wholesale price of natural gas[1]	+ $1/Gj	nominal	+ 13
US exchange rate – strengthening CDN dollar	+ $0.01 (CDN to US dollar)	nominal	+ 2
Short-term interest rates	+1.0%	- 2	- 2
Increase in water consumption – Alberta	+3.0%	+4	+4
Canadian federal and provincial income tax rates	-1.0%	+ 1	+ 3

(1) Sensitivities to wholesale prices of electricity and natural gas include the impact of fair value changes in derivative financial instruments that are not hedges for accounting purposes.

CONTROLS AND PROCEDURES

For purposes of certain Canadian securities regulations, EPCOR is a "Venture Issuer". As such, effective November 23, 2007, it was exempted from the requirements of MI 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings as long as it files Basic Annual Certificates and Basic Interim Certificates for periods ending on or after December 31, 2007. Accordingly, the Chief Executive Officer and Chief Financial Officer have reviewed the annual information form, annual financial statements and annual MD&A, for the year ended December 31, 2007. Based on their knowledge and exercise of reasonable diligence they have concluded that these materials fairly present in all material respects the financial condition, results of operations and cash flows of the Company for the periods presented and they do not contain any misrepresentations.

In addition, as of December 31, 2007, management conducted an evaluation of the design and effectiveness of the Company's disclosure controls and procedures. The evaluation took into consideration the Company's Disclosure Policy, the sub-certification process that has been implemented, and the functioning of its Disclosure Committee. In addition, the evaluation covered the Company's processes, systems and capabilities relating to public disclosures, and the identification and communication of material information. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's disclosure controls and procedures are appropriately designed and effective.

Also as of December 31, 2007, management conducted an evaluation of the design of internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company's internal controls over financial reporting are appropriately designed.

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

There were no changes in the Company's internal controls over financial reporting that have occurred during the year ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

NEW ACCOUNTING STANDARDS IN 2007

Financial instruments, hedges and comprehensive income

Commencing January 1, 2007, we adopted new accounting standards as issued by the Canadian Institute of Chartered Accountants (CICA) for Comprehensive Income, Equity, Financial Instruments and Hedges. In accordance with the new standards, our comparative financial statements have not been restated as a result of implementing the new accounting standards except to reclassify unrealized foreign currency translation gains and losses on net investments in self-sustaining foreign operations from the cumulative translation adjustment account to accumulated other comprehensive income, both within shareholder's equity.

A statement called Consolidated Statement of Comprehensive Income has been added to our consolidated financial statements. This statement includes net income and the components of other comprehensive income such as (a) unrealized gains or losses arising from the translation of net investments in self-sustaining foreign operations, (b) the changes in fair value of the effective hedge portion of derivative instruments used in cash flow hedges of electricity sales and purchases of anticipated foreign currency cash flows and (c) changes in the fair value of available-for-sale financial instruments. As the foreign exchange gains and losses are realized or the hedged item of the cash flow hedge affects income, these items of other comprehensive income are reclassified to the income statement. Other comprehensive income is intended to capture the changes in the fair value of the financial instruments, derivatives or translated balances which would not otherwise be recorded in the financial statements.

Each component of the statement of comprehensive income is recorded net of income taxes. Accumulated other comprehensive income is a new component of shareholder's equity.

Financial instruments

The new standards require that financial assets be classified 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 must be recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

We classify our cash, cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading, and measure them at fair value. Accounts receivable 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 values and fair values of other financial instruments held at December 31, 2007 are as follows:

	Carrying value					
($millions)	Held for trading	Available for sale	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets	$60	$63	$98	$ -	$ 221	$ 224
Long-term debt (including current portion)	-	-	-	2,139	2,139	2,226

Long-term debt includes The City of Edmonton debentures which are offset by the payments made by the Company into the sinking fund. Although the accumulated contributions to the sinking fund are classified as available for sale, they are included as an offset to long-term debt under financial liabilities in the table above, consistent with how they are presented on the balance sheet. The accumulated contributions to the sinking fund and our interest in the PERH preferred shares (included in other assets) are measured at cost as they are not quoted in an active market.

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 utilizing the effective interest method. Prior to January 1, 2007, transaction costs related to long-term debt were deferred and amortized on a straight-line basis over the term of the debt. Accordingly, we reclassified $15 million of debt issue costs from other assets to long-term debt effective January 1, 2007 and are amortizing them over the term of the debt using an effective interest rate.

Risk management and hedging activities

We are exposed to changes in energy commodity prices, foreign currency exchange rates and interest rates. We use various risk management techniques, including derivative instruments such as forward contracts, fixed-for-floating swaps, and option contracts, to reduce this exposure. The derivative instruments assets and liabilities used for risk management purposes consist of the following:

($millions)	Energy Cash flow hedges	Energy Non-hedges	Foreign exchange Non-hedges	Interest rate Non-hedges	Total
Total derivative instruments net assets (liabilities) as at December 31, 2007	$(93)	$ 75	$24	$ -	$ 6
Total derivative instruments net assets (liabilities) as at December 31, 2006	-	(11)	5	1	(5)

We use various open-market derivative instruments with arm's-length parties, including CfDs, to manage our exposure to risks associated with electricity and natural gas prices, foreign exchange rates and interest rates. These derivative instruments are recorded at fair value on the balance sheet unless they are designated as hedges which are effective, or if we elect 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 our expected purchase, sale or usage requirements.

At December 31, 2007, the fair value of our aggregate energy commodity derivatives used for risk management purposes, including derivatives that were not designated as hedges for accounting purposes, was in a net derivative liability position. This was due to a net long position for the short-term portion of the financial electricity portfolio combined with decreases in the forward Alberta electricity prices for 2008, relative to the contract prices. In addition, a net short position for the long-term portion of the financial electricity portfolio combined with increases in the forward Alberta electricity prices for the period from 2009 to 2016 resulted in a net derivative liability for these contracts. This derivative liability position was partly offset by the net derivative asset for unrealized gains on our natural gas supply contracts due to increases in forward natural gas prices relative to the contract prices.

Unrealized and realized gains and losses on energy derivatives that are not designated as hedges for accounting purposes are recorded in energy revenues, energy purchases or cost of fuel as appropriate. For energy derivatives that are designated as hedges, unrealized gains and losses are recorded in other comprehensive income and reclassified to net income as energy revenues or energy purchases when realized.

For the year ended December 31, 2007, the fair value of our forward foreign currency contracts increased, resulting in unrealized gains primarily due to the impact of a strengthening Canadian dollar in the current year on forward foreign exchange sales contracts used to hedge $US-denominated revenues. This was partly offset by higher unrealized losses on forward foreign exchange purchase contracts used to hedge anticipated $US-denominated purchases in 2007. The weighted average fixed exchange rate for contracts outstanding at December 31, 2007 was US$0.90 (December 31, 2006 - US$0.88) for every Canadian 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. Unrealized and realized gains and losses on interest rate derivatives that are not designated as hedges for accounting purposes are recorded in financing expenses. Unrealized gains and losses on foreign exchange or interest rate derivatives that are designated as hedges are recorded in other comprehensive income and reclassified to net income as energy revenues, foreign exchange gains and losses, or financing expenses when realized.

Energy derivatives designated as accounting hedges

At December 31, 2007, the net fair value of energy financial derivative instruments designated and qualifying for hedge accounting was a liability of $93 million and is included in derivative instruments assets and derivative instruments liabilities on the consolidated balance sheet. Prior to January 1, 2007, the fair value of financial derivative instruments that qualified for hedge accounting was not recorded in the balance sheet and was disclosed as an off-balance sheet item. The January 1, 2007 net fair value of these financial derivative instruments that were designated and qualified for hedge accounting was a liability of $60 million. Unrealized gains and losses for fair value changes on these financial derivatives that qualify for hedge accounting are recorded in other comprehensive income.

Energy derivatives not designated as accounting hedges

Unrealized changes in fair value on financial and non-financial derivatives that either do not qualify or we elect not to apply for hedge accounting treatment, and non-financial derivatives that do not qualify for the expected purchase, sale or usage requirements of the contract, are recognized in net income. The corresponding unrealized changes in the fair value of the associated hedged exposures are not recognized in income. 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. As a result, the recording of gains or losses for changes in fair values of derivative instruments for accounting purposes does not necessarily represent the underlying economics of the hedging transaction.

For example, we have more physical supply of power in Alberta from our generating stations and power purchased under PPAs than we have contracted to physically sell. We utilize financial sells to reduce our exposure to changes in the price of power in Alberta. Economically, we benefit from higher Alberta pool prices due to our net long position, as our expected physical supply is in excess of our physical and financial sells. However, financial sells 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 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 economic gains on the physical supply. This economic gain will be recognized in later periods when power is produced and sold. The opposite is true for forward price decreases in Alberta power prices.

As a result of adopting the new accounting standards, all non-financial derivative instruments are required to be 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 our expected purchase, sale or usage requirements. We hold certain physical power and natural gas purchase and sales contracts that are used to meet power generation and retail customer requirements. Certain of the natural gas purchase contracts were not designated as contracts used in accordance with our expected purchase requirements, as defined in the accounting standard, since the natural gas can at times be re-sold in the market and not entirely used to produce electricity or to sell to end-use consumers. These contracts were therefore recorded at fair value in the balance sheet. As at January 1, 2007, the fair valuation of fuel supply contracts in Power LP resulted in an increase in derivative instruments assets of $96 million, an increase in non-controlling interests of $66 million, an increase in future income tax liabilities of $10 million, and an increase in opening retained earnings, net of income taxes, of $20 million. The fair valuation of other physical power and natural gas purchase and sales contracts resulted in opening transition adjustments that increased derivative instruments assets by $45 million and derivative instruments liabilities by $45 million.

In addition, opening 2007 retained earnings decreased $8 million net of income taxes to recognize the fair value of the ineffective hedge portion of previously deferred losses.

Other Comprehensive Income

As of January 1, 2007, the changes in the fair value of the effective hedge portion of the financial derivative contracts used to manage our energy portfolio and designated as accounting hedges, are recorded in other comprehensive income. The ineffective portion of the contracts is recorded in net income. Prior to January 1, 2007, such financial contracts were recorded in the income statement as they settled.

The transition adjustment to opening accumulated other comprehensive income included unrealized losses, net of income taxes, of $42 million related to cash-flow hedging relationships and $1 million of unrealized gains, net of non-controlling interests and income taxes, related to previously discontinued cash flow hedges no longer deferred in derivative instruments assets and liabilities in the consolidated balance sheet.

For the year ended December 31, 2007, a cumulative loss, net of income taxes, of $70 million was recorded in other comprehensive income for the effective portion of cash flow hedges, and an unrealized loss, net of income taxes, of $46 million was re-classified to energy purchases and revenues as appropriate. There was no ineffective portion of cash flow hedges for which unrealized losses were required to be recognized in income. Of the $64 million in net losses recorded in accumulated other comprehensive income, net losses of $45 million (net of taxes of $20 million) related to derivative instruments designated as cash flow hedges at December 31, 2007 are expected to settle and be reclassified to net income over the next twelve months.

Unrealized gains on financial instruments designated as available for sale are related to certain venture capital investments which are focused on strategic elements of the energy and water value chain. Some of the shares held are not typically traded on an exchange and therefore are difficult to value. During the year ended December 31, 2007, an unrealized fair value gain on a venture capital investment was recognized in other comprehensive income as a result of market value appreciation after the initial public offerings of the investment in June 2007. We have considered the effect of illiquidity and the restrictions on the shares held in determining their fair value.

FUTURE ACCOUNTING CHANGES

International financial reporting standards

In 2005, the CICA announced plans to converge Canadian GAAP with International Financial Reporting Standards (IFRS) over a transition period from 2006 to 2011. The CICA has indicated that Canadian reporting issuers will need to begin reporting under IFRS by the first quarter of 2011 with comparative figures. We have developed a high level plan for the implementation of IFRS and are assessing the impact of the differences in accounting standards to EPCOR's financial statements. Based on our analysis thus far, we anticipate that the more significant differences for EPCOR will be in the areas of property, plant and equipment, regulatory accounting, joint arrangements, financial instruments, hedges, income taxes, impairments, business combinations, goodwill, asset retirement obligations, foreign exchange and financial statement disclosures. It is not practically possible to quantify the impact of these differences at this stage. We also expect to make changes to certain processes and systems before 2010, in time to enable us to record transactions under IFRS for comparative purposes in our financial reporting in 2011.

Capital disclosures and financial instruments – presentation and disclosures

On December 1, 2006, the CICA issued the new CICA Handbook Sections 1535, 3862 and 3863 for Capital Disclosures and Financial Instruments – Disclosures and Presentation. Effective January 1, 2008, the Company will adopt these new accounting standards. As required by the new standards, the Company will disclose quantitative and qualitative information that is intended to provide users of the financial statements with additional insight into the Company's risks associated with financial instruments and how these risks are managed. These risks include credit, liquidity and market risks. The disclosures will also include information on how the Company manages its capital.

Inventories

Effective January 1, 2008 the new CICA Handbook Section 3031 Inventories will replace Section 3030. The new section requires inventories to be measured at the lower of cost and net realizable value, which is consistent with EPCOR's current policy for measuring inventories held for resale. EPCOR currently measures inventories held for consumption at the lower of cost and replacement value. We do not expect the adoption of the new standard to result in a material transition adjustment to the financial statements.

Rate-regulated operations

In December 2007 the CICA amended Handbook Sections 1100 – Generally Accepted Accounting Principles and 3465 – Income Taxes, and made consequential amendments to Accounting Guideline 19 – Disclosures by Entities Subject to Rate Regulation. The amendments removed the temporary exemption from the requirement to apply Section 1100 to the recognition and measurement of assets and liabilities arising from rate regulation. They also require rate-regulated enterprises to recognize future income taxes separate from the regulatory asset or liability for the future recovery from or refund to customers for those income taxes. The guidance is now consistent with corresponding guidance under U.S. generally accepted accounting principles. We will assess our accounting for rate-regulated operations in relation to these amendments but do not expect them to be material to EPCOR. These amendments are effective January 1, 2009.

Goodwill and intangible assets

In February 2008, the CICA issued Handbook Section 3064 – Goodwill and Intangible Assets and consequential amendments to Section 1000 – Financial Statement Concepts. The new section establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The provisions relating to the definition and initial recognition of intangible assets, including internally generated intangible assets, are equivalent to the corresponding provisions in IFRS. The provisions relating to goodwill are unchanged from those of the replaced Section 3062 – Goodwill and Other Intangible Assets. EPCOR will review its capitalization policies and practices for internally developed software for compliance with the new standard which will determine the impact of the amendments to EPCOR by the end of 2008. These amendments are effective January 1, 2009.

SIGNIFICANT ACCOUNTING POLICIES

Revenue recognition under PPAs

Our Genesee power generation units 1 and 2 operate under a PPA. Under the terms of the Genesee 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 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 in 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.

Revenues from the Company's power generation plants located outside of Alberta are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. These contractual arrangements are also commonly referred to as PPAs. Revenues under the Curtis Palmer PPA are recognized at the lower of (1) the cumulative billable contract price per megawatt hour (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 over the average price is recorded as deferred revenue.

Financial commodity contracts

EPCOR uses CfDs for risk management purposes. Our accounting policies for financial instruments, including CfDs and non-financial derivatives are discussed under New Accounting Standards in 2007.

Consolidation of Power LP

While EPCOR owns only 30.6% of the outstanding units of Power LP, it controls Power LP under generally accepted accounting principles. Accordingly, the acquisition of EPCOR's interest in Power LP was accounted as a business combination with full consolidation of the financial position and results of Power LP in the financial statements of EPCOR from the date of acquisition.

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.

Electricity revenues, costs and unbilled consumption

Due to the imprecision in customer consumption data received from load settlement agents, the lag between billing dates and meter reading dates and the lag between billing dates and financial reporting dates, we must use estimates for determining the amount of energy consumed but not yet billed. These estimates affect accrued revenues and accrued energy costs of the Energy Services segment. There are a number of variables in the computation of these estimates, and the underlying energy settlement processes within EPCOR and the Alberta and Ontario electric systems are complex. Owing to the factors above and the statutory delays in final load settlement determinations and information, adjustments to previous estimates could be material. Estimates for unbilled consumption average about $90 million at the end of each month and these estimates vary from $75 million to $115 million. Adjustments of estimated revenues to actual billings were less than $6 million per month.

Fair values

We are required to estimate the fair value of certain assets or 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, we use 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 to 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 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.

Estimates of fair value for purchase price allocations, and goodwill and other asset impairments as described above, are mainly 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.

Allowance for doubtful accounts

We continually review our aged accounts receivable and assess the underlying credit quality of the customers or counterparties. The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is based on a number of factors including the aging of receivables, historical write-offs within customer groups, assessments of the collectibility of amounts from individual customers and general economic conditions. EPCOR's allowance account averaged $6 million (2006 - $6 million) and reported bad debts, net of recoveries were $1 million in 2007 (2006 - $3 million). The estimate of the allowance affects accounts receivable and all segments' operations, maintenance and administration expenses.

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 common life characteristics of common assets.

Income taxes and amounts in lieu of income taxes

EPCOR follows the asset and liability method of accounting for income taxes and amounts in lieu of income taxes. Income taxes and amounts in lieu of income taxes are determined based on estimates of our current income taxes and 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. 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 income taxes and amounts in lieu of income taxes, future income tax assets and liabilities and any related valuation allowance might vary from actual amounts incurred.

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. Similarly, income taxes and amounts in lieu of income taxes will vary with taxable income and, under certain conditions, with fair values of assets and liabilities. Accordingly, it is not possible to provide a reasonable quantification of the range of these estimates that would be meaningful to readers.

PPA availability incentives

Electricity revenue from the Genesee 1 and 2 units operating under PPAs 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. At December 31, 2007, $nil (2006 - $2 million) was deferred in the balance sheet and $27 million (2006 - $26 million) was recognized in energy sales during the year.

NON-GAAP FINANCIAL MEASURES

We use cash flow from operations to measure the Company's ability to generate funds from current operations. Cash flow from operations is a non-GAAP financial measure, does not have any standardized meaning prescribed by GAAP and is unlikely to be comparable to similar measures published by other entities. However, it is presented since it is commonly referred to by debt holders and other interested parties in evaluating the Company's financial position and in assessing its credit worthiness. A reconciliation of cash flow from operations to cash flow from operating activities is as follows:

Year ended December 31	2007	2006	2005
Cash flow from operations	**$ 517**	**$ 547**	**$ 493**
Change in non-cash operating working capital	24	42	(14)
Cash flow from operating activities	**$ 541**	**$ 589**	**$ 479**

RELATED PARTY TRANSACTIONS

EPCOR enters into various transactions with its sole shareholder, The City of Edmonton. These transactions are in the normal course of operations and are recorded at the exchange value generally based on normal commercial rates or as agreed to by the parties.

We recorded financing expenses of $54 million in 2007 ($58 million - 2006) on EPCOR's debt obligation to The City of Edmonton. This debt obligation relates to debt capital raised by The City of Edmonton prior to 1996 when EPCOR commenced raising capital directly. The decrease in interest expense in 2007 corresponds to the decrease in the net obligation. The outstanding balance of the net obligation to The City of Edmonton was $243 million at December 31, 2007 (2006 - $309 million).

Sales from EPCOR to The City of Edmonton included electricity and water, and the provision of maintenance, repair, construction and customer care services totaling $77 million in 2007 (2006 - $69 million). We paid franchise fees and property taxes to The City of Edmonton of $49 million (2006 - $46 million). The City of Edmonton provided miscellaneous services to EPCOR totaling $7 million (2006 - $8 million).

Included in the Company's revenues is $3 million (2006 - $1 million) for the provision of management services by Power LP to PERC under a long-term management agreement. At December 31, 2007, accounts receivable included $1 million (2006 - $nil) due from PERC.

FOURTH QUARTER REVIEW AND QUARTERLY RESULTS

Quarters ended	Revenues	Net income from continuing operations	Net income (loss) from discontinued operations	Net income
	(Unaudited, in $ millions)			
December 31, 2007	$ 969	$ 59	$ -	$ 59
September 30, 2007	930	67	-	67
June 30, 2007	865	53	-	53
March 31, 2007	899	98	-	98
December 31, 2006	728	16	1	17
September 30, 2006	702	47	9	56
June 30, 2006	689	383	-	383
March 31, 2006	812	186	-	186

For the quarter ended December 31, 2007, consolidated net income from continuing operations increased by $43 million from the same quarter in the prior year primarily due to unrealized fair value gains on derivative financial instruments in our Alberta wholesale and merchant portfolio due to a short position on financial contracts and a decrease in Alberta forward power prices. In addition, income from Power LP operations was higher primarily due to unrealized fair value gains on its natural gas contracts in 2007 and foreign exchange losses on the translation of its U.S. dollar debt in 2006. These increases were partly offset by the impact of future tax rate reductions which were substantively enacted in December 2007, unfavourable fair value changes on the Joffre CfD, the absence of the Calpine short-term tolling arrangements which were in place in 2006, and lower income from the Joffre plant. In addition, losses were realized on forward foreign exchange contracts in the fourth quarter of 2007 whereas gains were realized in the corresponding period in 2006.

Segment results for the fourth quarter included higher operating income in Energy Services with an operating profit of $56 million compared with an operating loss of $7 million for the corresponding period in 2006. Energy Services' fourth quarter results included favourable unrealized fair value changes on merchant and wholesale positions in Alberta, partly offset by reduced income from Joffre and the absence of the Calpine short-term tolling arrangements.

Generation's operating income increased to $97 million in the fourth quarter of 2007 from $52 million in the same period in 2006 primarily due to higher income from Power LP and lower maintenance costs at the Genesee units. These increases were partly offset by an unrealized fair value decrease in the Joffre CfD and losses realized on forward foreign exchange contracts in the fourth quarter of 2007 compared with gains realized in the fourth quarter of 2006.

Distribution and Transmission's operating income increased to $8 million in the fourth quarter of 2007 from $6 million of the same period in 2006, primarily due to an increase in distribution volumes.

Water Services' operating income increased to $13 million in the fourth quarter of 2007 compared with $8 million in the fourth quarter of 2006, primarily due to higher rates for water sales.

Events for 2007 and 2006 quarters that have significantly impacted net income from continuing operations and net income and cash flows and the comparability between quarters are:

- September 30, 2007 third quarter results include higher Alberta electricity margins due to favourable settlements on financial sales as a result of higher contract prices and lower Alberta power prices, and higher income from the acquired PPAs. In addition the results included favourable unrealized fair value changes in financial and non-financial derivative instruments in Alberta merchant and wholesale positions due to lower forward power prices combined with a net short position. This was partly offset by an unfavourable fair value change in the Joffre CfD due to a lower spark spread in the quarter.

- June 30, 2007 second quarter results include unrealized fair value decreases in derivative financial instruments which were not designated as hedges for accounting purposes, resulting from increasing forward market prices. In addition, income from Power LP included unrealized fair value decreases for the natural gas supply contracts resulting from decreasing forward natural gas prices and contract price changes for the Tunis plant.

- March 31, 2007 first quarter results include a gain from the sale of a 10% interest in the Battle River PSA, a reduction of future income tax expense resulting from a reorganization of two subsidiaries within the Energy Services segment, and higher income from Power LP due to the fair value changes in the natural gas supply contracts for its Ontario generation plants which were required under the implementation of the new accounting standard for financial instruments effective January 1, 2007. These gains were partly offset by unrealized fair value decreases in derivative financial instruments resulting from a combination of increasing volumes of financial sales contracts not qualifying for hedge accounting and increasing Alberta forward power prices.

- December 31, 2006 fourth quarter results include unrealized fair value decreases in derivative financial instruments which were not designated as hedges for accounting purposes, resulting from increased forward power prices. In addition, income from Power LP included unrealized foreign exchange losses on the translation of US dollar debt. These events were partly offset by increased generation from a short-term tolling arrangement with Calpine, higher generation incentive income and realized gains on forward foreign exchange contracts.

- September 30, 2006 third quarter results include a net income increase from discontinued operations for the reduction of the Clover Bar asset retirement obligation offset by reduced Alberta electricity margins from the Battle River and Sundance PPAs resulting from the sale of partial interests in these agreements in the second quarter of 2006.

- June 30, 2006 second quarter results include the sale of a 55% interest in the Battle River PPA and related transactions. The regulatory decisions for the 2005/2006 distribution and transmission tariffs and the RRT non-energy charge were received in the second quarter of 2006 resulting in an increase in net income. Future income tax assets and liabilities were adjusted to reflect the corporate income tax rate reductions that were enacted by the governments of Alberta and Canada in the quarter, which reduced net income.

- March 31, 2006 first quarter results include the tax impact of the Generation reorganization whereby a Generation subsidiary became subject to federal and provincial income taxes rather than the PILOT Regulation. As a result, additional deductions are available for income tax purposes and the net tax effect was recognized as non-current future income tax assets in the balance sheet with a corresponding increase in net income. In addition, unrealized fair value changes in derivative financial instruments increased net income.

ADDITIONAL INFORMATION

Additional information relating to EPCOR including the Company's 2007 Annual Information Form is available on SEDAR at www.sedar.com.