EPCOR Utilities Inc.
Interim Report
September 30, 2007

Management's Discussion and Analysis

This management's discussion and analysis ("MD&A"), dated November 2, 2007, should be read in conjunction with the unaudited interim consolidated financial statements of EPCOR Utilities Inc. (hereinafter the "Company", "EPCOR", "we", "our" or "us") for the nine months ended September 30, 2007 and 2006 and in conjunction with the audited consolidated financial statements and MD&A for the year ended December 31, 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", "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, weather and economic conditions, competitive pressures, construction risks, obtaining financing 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.

SIGNIFICANT EVENTS

Redemption of preferred shares

Effective September 30, 2007, EPCOR Preferred Equity Inc., a subsidiary of the Company, redeemed 8 million Cumulative Redeemable Perpetual First Preferred Shares, Series I ("Preferred Shares") at par for $200 million. The Preferred Shares were issued on September 27, 2002. The redemption was completed on October 1, 2007 and funded from cash balances and debt.

The carrying value of the Preferred Shares prior to their redemption by the Company 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 between the redemption price and the carrying value has been charged to non-controlling interests in the consolidated statements of income.

Asset Backed Commercial Paper

At September 30, 2007, the Company held $67 million in Canadian third party asset backed commercial paper (“ABCP”), all of which was purchased during the third quarter. The Company’s ABCP has been directly impacted by the current liquidity issues affecting that segment of the commercial paper market and as a result, all of the Company’s ABCP matured with no payment of principal, accrued interest or roll over. All of the trusts in which the Company’s ABCP investments are held are rated R-1 (high) by DBRS Limited (“DBRS”), which is their highest rating for commercial paper. DBRS has placed these trusts “Under Review with Developing Implications” following an announcement on August 16, 2007 that a consortium representing banks, asset providers and major investors had agreed in principle to a long-term proposal and interim arrangements regarding the ABCP ("the Montreal Accord”). Under this proposal, 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”). On October 15, 2007, the standstill arrangements of the Montreal Accord were extended to December 14, 2007.

Due to the uncertainties associated with the timing of repayment, the ABCP investment is classified as non-current under 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 reduction in fair value of $4 million during the third quarter, representing the difference between the original purchase price of $71 million and the estimated fair value of $67 million at September 30, 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 downgrades of the applicable ABCP issuing trusts, observable interest rates and credit spreads for estimating future interest payments and applicable discount rates, estimated recovery periods based on the estimated lives of the underlying assets of the issuing trusts, and ranges of recoverability based on publicly available default statistics for 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 and the quality and tenor of the underlying assets and instruments in the applicable trusts. Accordingly, the estimate of fair value of ABCP may change materially as events unfold and more information becomes available.

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. At September 30, 2007, the Company’s subsidiary, EPCOR Power L.P., did not have any investments in ABCP. 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.

CONSOLIDATED RESULTS OF OPERATIONS

Net income from continuing operations

(Unaudited, $ millions)	Three months	Nine months
Net income from continuing operations for the periods ended September 30, 2006	**$ 47**	**$ 616**
Higher Alberta electricity margin	11	2
Unrealized fair value changes in financial and non-financial derivative instruments, excluding Power LP	10	(32)
Cumulative translation account adjustment in 2006 for the sale of Frederickson to Power LP	6	6
Higher water sales	5	10
Higher availability incentive income	5	3
Lower (higher) financing expenses and preferred share dividends, excluding Power LP financing	(3)	21
Lower income from Power LP	(9)	(11)
Impact of income tax rate reductions on future income tax assets and liabilities, excluding Power LP	-	22
Impact of recording a net future income tax asset associated with the Energy Services reorganization on January 1, 2007	-	10
Regulatory decisions for 2005 distribution and transmission tariffs and 2005 RRT non-energy charges received in 2006	-	(7)
Impact of recording a net future income tax asset associated with the restructuring of EPCOR Generation Inc. on January 3, 2006	-	(117)
Gains on sales of interests in Battle River PSA	-	(297)
Other	(5)	(8)
Increase (decrease) in net income	20	(398)
Net income from continuing operations for the periods ended September 30, 2007	**$ 67**	**$ 218**

Net income from continuing operations was $67 million and $218 million for the three and nine months ended September 30, 2007 respectively, compared with $47 million and $616 million for the corresponding periods in 2006.

- Alberta electricity margins were higher due to favourable settlements on financial sales as a result of higher contract prices and lower power prices in the month of September 2007 compared with the prior year. Income from the acquired Power Purchase Arrangements ("PPAs") also increased due to higher penalty payments received resulting from higher rolling average pool prices during unplanned plant outages. These variances were partly offset by the impact of our reduced interest in the Battle River Power Syndicate Agreement ("Battle River PSA") and lower generation from Genesee 3 compared with the prior year. Alberta electricity margins from our retail Regulated Rate Tariff ("RRT") customers were lower in 2007 due to changes in the Energy Price Setting Plan ("EPSP") effective July 1, 2006, and higher energy settlements associated with customer billings.

- The unrealized fair value changes in financial and non-financial derivative instruments for the quarter include favourable changes in Alberta merchant and wholesale positions due to lower forward power prices compared with the same quarter of the prior year combined with a net short position. This was partly offset by an unfavourable fair value change in the Joffre contract-for-differences ("CfD") due to a lower spark spread in the current quarter compared with the spark spread in the prior year's third quarter. (See Segment Results - Generation).

For the nine month period, the year over year variances of the fair value changes in the Alberta merchant and wholesale positions, forward foreign currency contracts, and Joffre CfD were unfavourable. The unfavourable change in the Alberta merchant and wholesale position was due to an increase in financial sales contracts which were not designated as hedges for accounting purposes combined with higher forward Alberta power prices than in the prior year. Anticipated generation decreased due to our reduced interest in the Battle River PSA and a planned outage on the Genesee 3 facility which caused the increase in the volume of financial sales contracts not qualifying as hedges for accounting purposes. The decrease in fair value of forward foreign currency contracts was due to a strengthening Canadian dollar in the current year. The decrease in the fair value of the Joffre CfD was due to a lower spark spread in 2007 compared with 2006.

- On August 1, 2006, the Company sold certain subsidiaries associated with its interest in Frederickson Power L.P. ("Frederickson") to EPCOR Power L.P. ("Power LP", a subsidiary of EPCOR). No gain or loss was recognized on the intercompany sale. However, previously deferred foreign exchange losses on the Company's net investment in the Frederickson operations and a foreign exchange gain on repayment of the US dollar debt designated as a hedge of the net investment in the foreign operations were recognized, resulting in a net foreign exchange loss of $6 million, in the third quarter of 2006.

- Water sales were higher in 2007 compared with 2006 primarily due to rate increases which were implemented in April 2007.

- Availability incentive revenues earned under the terms of the Genesee 1 and 2 PPAs increased in the third quarter due to revisions for higher forward Alberta power prices and significantly fewer outage days in 2007 compared with 2006.

- 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 $87 million outstanding under a three-year credit facility, which had been drawn to hedge the Company's investment in Frederickson, and scheduled repayments of obligations to the City of Edmonton. The Company capitalizes an allowance for funds used during construction ("AFDUC") to provide for the cost of capital invested in rate-regulated construction activities. AFDUC was higher in 2007 than 2006 for the E.L. Smith water treatment plant construction project. Preferred share dividends decreased due to the redemption of $150 million of subsidiary preferred shares on June 30, 2006. 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. This change resulted in an $8 million decrease in non-controlling interests in the second quarter of 2007. These decreases were partly offset by a $4 million reduction in fair value of ABCP in the current quarter as described under Significant Events.

- Net income from Power LP was lower in 2007 compared with the prior year primarily due to the fair value changes in the natural gas supply contracts for its Ontario generation plants. These fair value adjustments were required by the new accounting standard for financial instruments that was implemented on January 1, 2007. The contracts did not qualify for the designation under the accounting standard as contracts used for the purpose of receipt of natural gas in accordance with our expected purchase or usage requirements and therefore were measured at fair value. There was no comparable adjustment in 2006 as the new accounting standard is effective January 1, 2007. The opening fair value adjustment at January 1, 2007 was recorded in retained earnings. See Changes in Accounting Standards – Accounting Changes for 2007.

Net income also decreased due to realized losses on forward interest rate contracts, higher financing costs related to the 2006 PEV acquisition by Power LP, an impairment charge in the third quarter of 2007 in respect of certain PEV management contracts, and lower pricing and volume at the Curtis Palmer plant.

Partly offsetting these reductions were higher foreign exchange gains on the translation of Power LP's US denominated debt in 2007 due to an increase in debt balances for the Frederickson and Primary Energy Ventures LLC ("PEV") acquisitions in 2006 and a strengthening Canadian dollar in 2007. Fair value gains on the foreign exchange contracts were also higher in 2007.

- In the second quarter of 2006, the enactment of income tax rate reductions resulted in an increase in income tax expense of $23 million. These tax changes consisted of a provincial rate reduction effective April 1, 2006 and a federal income tax rate reduction that is scheduled to occur in increments over the period from January 1, 2008 to December 31, 2010. The tax rate reduction announced in June 2007 resulted in an increase in income tax expense of $1 million.

- On January 1, 2007, the Company reorganized two subsidiaries within the Energy Services segment that operate the regulated retail business. As part of the transactions, one of the subsidiaries, which was previously exempt from income taxes became subject to tax 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.

- In the second quarter of 2006, the Alberta Energy and Utilities Board ("AEUB") issued its decisions relating to the Company's general tariff applications for its electricity transmission, distribution and RRT services for the period from January 1, 2005 through December 31, 2006. Prior to receiving the Decisions, the Company had billed customers and recorded revenues based on AEUB-approved interim rates for 2005 and 2006. The 2005 effect of these decisions was a $7 million contribution to net income, which was recognized in the second quarter of 2006.

- The January 3, 2006 reorganization of the Generation subsidiaries resulted in 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 Regulation, thereby increasing income in 2006 by $117 million.

- On January 1, 2007, we sold a 10% interest in the 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 PPA and related interest in the

Battle River PSA to ENMAX Corporation over a four-year period ending in January 2010.

The initial sale in June 2006 of a 55% interest was for $343 million. The Company also sold a 17.8% interest in the Sundance Power Syndicate Agreement ("Sundance PSA") to non-EPCOR syndicate members for $58 million. These transactions resulted in a pre-tax gain of $378 million and $51 million of associated income tax expense.

Net income and net income from discontinued operations

(Unaudited, $ millions)	Three months	Nine months
Net income for the periods ended September 30, 2006	**$ 56**	**$ 625**
Increase (decrease) in net income from continuing operations – see previous table	20	(398)
Decrease in income from operation of the Clover Bar generation plant	(9)	(9)
Increase (decrease) in net income	11	(407)
Net income for the periods ended September 30, 2007	**$ 67**	**$ 218**

Net income for the three and nine months ended September 30, 2007 was $67 million and $218 million, respectively. Net income for the three and nine months ended September 30, 2006 was $56 million and $625 million, respectively. Net income from discontinued operations was $9 million in 2006 which included a reduction of the Clover Bar asset retirement obligation net of associated income taxes. There was no net income from discontinued operations for the three and nine months ended September 30, 2007.

Revenues

(Unaudited, $ millions)	Three months	Nine months
Revenues for the periods ended September 30, 2006	**$ 702**	**$ 2,203**
Higher energy sales	126	359
Higher Power LP revenues	78	214
Unrealized fair value changes in derivative financial and non-financial instruments	11	(91)
Higher commercial and other sales	13	9
Increase in revenues	228	491
Revenues for the periods ended September 30, 2007	**$ 930**	**$ 2,694**

Consolidated revenues for the three and nine months ended September 30, 2007 were higher than for the corresponding periods in 2006 primarily due to:

- Energy sales increased due to higher natural gas trading activities, new power trading activities in the Pacific Northwest power market, favourable settlements of financial sales due to higher contract prices and increased volume, higher revenues from RRT customers due to higher pricing, and higher availability incentive income due to higher forward Alberta power prices and significantly fewer outage days for 2007. These favourable variances were partly offset by a decrease in generation related to our reduced interests in the Battle River PSA in June 2006 and January 2007, expiry of the short term tolling arrangement with Calpine Power Income Fund for operation of their Calgary Energy Centre for the period from February 16, 2006 to June 30, 2006 and the month of September 2006.

- Revenues from Power LP were $153 million for the three months and $461 million for the nine months ended September 30, 2007 compared with $75 million and $247 million for the corresponding periods in 2006. The increases were primarily due to the acquisition of PEV on November 1, 2006 and Frederickson on August 1, 2006 as well as favourable changes in the fair value of foreign exchange contracts. The sale of Frederickson to Power LP had no impact on consolidated revenues. These favourable variances were partly offset by the non-recurrence of a settlement received from the Ontario Electricity Financial Corporation in the first quarter of 2006 and lower generation and pricing at the Curtis Palmer facility.

- Unrealized fair value changes on derivative financial instruments increased energy revenues for the quarter compared with the prior year primarily due to decreasing forward Alberta power prices on financial sales that were not designated as hedges for accounting purposes. This was partly offset by unfavourable changes in the fair value of the Joffre CfD resulting from a lower spark spread in the third quarter compared with the prior year. For the nine months ended September 30, 2007, unrealized fair value changes on derivative financial instruments decreased energy revenues due to higher forward Alberta power prices combined with an increase in financial sales contracts, and unfavourable fair value changes on the Joffre CfD due to a lower spark spread, compared with the prior year.

Capital spending and investment

(Unaudited, $ millions) **Nine months ended September 30**	**2007**	**2006**
Generation	$ 155	$ 38
Distribution and Transmission	72	37
Energy Services	8	5
Water Services	82	57
Corporate – other	14	8
	$ 331	**$ 145**

Capital expenditures for property, plant and equipment were higher for the nine months ended September 30, 2007 compared with the same period in 2006 due to construction activity on several projects including the Keephills 3 and Clover Bar generation projects, both of which commenced in the first quarter of 2007, new transmission infrastructure, the Downtown Edmonton Supply and Substation (“DESS”), and the EL Smith water treatment plant.

On February 26, 2007, EPCOR and TransAlta Corporation (“TransAlta”) announced their decision to build Keephills 3, a 450 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.

In December 2006, the AEUB approved our proposal to construct three natural gas-fired peaking power generation units for an aggregate gross generating capacity of 245 MWs at our Clover Bar site in northeast Edmonton. The first 45 MWs are expected to be commissioned in the first quarter of 2008 with subsequent capacity coming on line in late 2008 and 2009.

In the first quarter of 2007, Distribution and Transmission commenced construction of the DESS project which consists of a new high voltage transmission line, which will supply electricity to downtown Edmonton. Water Services' construction on the EL Smith water treatment plant expansion continued in 2007. Both projects are scheduled for completion in 2008.

SEGMENT RESULTS

Generation

Generation results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2007	**2006**	**2007**	**2006**
Revenues	$ 268	$ 192	$ 777	$ 580
Expenses	223	129	552	328
Operating income	**$ 45**	**$ 63**	**$ 225**	**$ 252**

(Unaudited, $ millions)	**Three months**	**Nine months**
Operating income for the periods ended September 30, 2006	**$ 63**	**$ 252**
Increased estimates of PPA availability incentive revenue	8	4
Cumulative translation account adjustment for the sale of Frederickson to Power LP in 2006	6	6
Write-down of venture capital investment	3	3
Lower operating income from Frederickson operations	-	(3)
Higher maintenance on Genesee 1 generating unit	(4)	(4)
Higher realized losses on foreign exchange derivatives	(5)	(8)
Unrealized fair value changes in derivative instruments	(8)	(24)
Lower operating income from Power LP	(18)	(3)
Other	-	2
Decrease in operating income	(18)	(27)
Operating income for the periods ended September 30, 2007	**$ 45**	**$ 225**

Generation's operating income for the quarter and nine months ended September 30, 2007 decreased $18 million and $27 million respectively, from the same periods in 2006. The key changes are as follows:

- Availability incentive revenue earned under the terms of the Genesee 1 and 2 PPAs increased due to revised estimates for higher forward Alberta power prices and significantly fewer outage days compared to the prior year.

- The sale of Frederickson to Power LP resulted in higher Power LP operating income and lower operating income for the balance of the Generation segment for the period from the date of sale on August 1, 2006. Other than the loss recorded in the prior year on the cumulative foreign currency translation, this sale had no overall impact on the Generation segment results.

- A venture capital investment was written down in the prior year to reflect its loss in value.

- A Genesee 1 maintenance outage occurred in the third quarter of 2007.

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

- The generation from the Joffre plant is subject to a CfD whereby the difference between spot electricity prices and variable operating costs, multiplied by the contracted volume is remitted by one counterparty to the other. The CfD effectively incorporates an Alberta spark spread which represents the difference between Alberta power prices and 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. If the price of power is less than the cost of natural gas to produce electricity, the spark spread is unfavourable. Unrealized fair value changes on the CfD decreased revenues by $10 million and expenses by $3 million in the third quarter and decreased revenues by $8 million and increased expenses by $4 million for the nine months ended September 30, 2007, due to a lower spark spread compared to the prior year.

  In addition, unrealized fair value changes on foreign exchange contracts entered into in anticipation of asset purchases related to the Clover Bar and Keephills 3 generation projects decreased operating income and increased expenses in the quarter and nine months ended September 30, 2007 due to a strengthening Canadian dollar.

- Power LP contributed a $3 million operating loss in the current quarter and $15 million of operating income in the third quarter of 2006. For the nine month period ended September 30, Power LP's operating income was $90 million in 2007 and $93 million in 2006. Power LP's revenues and expenses were higher by $78 million and $96 million, respectively for the quarter and $214 and $217 million, respectively for the nine month period ended September 30, 2007 compared with the corresponding prior year periods primarily due to the acquisition of PEV and Frederickson in the prior year. Revenues for both periods in 2007 also increased compared to the corresponding periods in the prior year due to favourable changes in the fair value of foreign exchange contracts, partly offset by lower revenues from the Curtis Palmer plant. For the nine month period, these increases in revenues were also partly offset by the non-recurrence of the settlement received from the Ontario Electricity Financial Corporation in the first quarter of 2006.

  Fair value changes in the natural gas supply contracts were the main contributors to the increase in expenses in Power LP, especially in the current quarter. Realized losses on foreign exchange contracts related to the PEV acquisition and an impairment charge in respect of certain PEV management contracts were recognized in the current quarter with no corresponding amounts in the prior year. These increases were partly offset by unrealized foreign exchange gains in 2007 on the translation of higher US dollar debt balances for the Frederickson and PEV acquisitions due to a strengthening Canadian dollar.

  Fair value changes for accounting purposes in the natural gas supply contracts and foreign exchange contracts are not representative of changes in the economic value of these contracts when considered in conjunction with the economically hedged item, such as future natural gas requirements, future power sales and future equipment purchases.

Distribution and Transmission

Distribution and Transmission results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2007	**2006**	**2007**	**2006**
Revenues	$ 63	$ 66	$ 181	$ 192
Expenses	52	57	150	156
Operating income	**$ 11**	**$ 9**	**$ 31**	**$ 36**

Distribution and Transmission's operating income increased in the three months ended September 30, 2007 compared with the same period in 2006 due to an increase in distribution revenue resulting from higher demand and prices in 2007. Total revenues were lower due to balancing pool rebates received from the Alberta Electricity System Operator for system access charges which were passed on to customers. Operating income decreased in the nine month period compared with the prior year due to the 2005/2006 rate decision received in June 2006 which resulted in the recognition of $6 million of operating income relating to 2005 service.

Energy Services

Energy Services results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2007	**2006**	**2007**	**2006**
Revenues	$ 599	$ 458	$ 1,759	$ 1,478
Expenses	548	436	1,683	1,382
Operating income	**$ 51**	**$ 22**	**$ 76**	**$ 96**

(Unaudited, $ millions)	**Three months**	**Nine months**
Operating income for the periods ended September 30, 2006	**$ 22**	**$ 96**
Unrealized fair value changes in derivative instruments	23	(21)
Higher Alberta electricity margin	16	2
Lower Ontario margin	(4)	(1)
Other	(6)	-
Increase/(Decrease) in operating income	29	(20)
Operating income for the periods ended September 30, 2007	**$ 51**	**$ 76**

Energy Services' operating income increased $29 million for the quarter and decreased $20 million for the nine months ended September 30, 2007 compared with the corresponding periods in 2006 due to the net impact of the following:

- The unrealized fair value changes in our financial electricity contracts were favourable in the current quarter due to a decrease in forward Alberta power prices on a net short position while forward Alberta power prices were increasing in the same period in 2006. For the nine month period, the unrealized fair value changes were unfavourable compared with the prior year due to higher forward Alberta power prices combined with an increase in financial sales contracts that were not designated as hedges for accounting purposes. The volume of these instruments that were recorded at fair value was higher in 2007 due to decreased generation as a result of our reduced interests in the Battle River PSA.

  These financial sales contracts hedge anticipated energy revenues on an economic basis. Unrealized fair value changes in derivative instruments recorded for accounting purposes are not representative of the changes in economic value when considering them in conjunction with the economically hedged item such as future power supply.

Unrealized fair value changes in our derivative instruments increased energy revenues by $22 million and decreased energy expenses by $1 million for the quarter. Increases in energy revenues and expenses resulting from the impact of decreasing forward Alberta power prices were partly offset by decreased trading activity in the Ontario power market for the three months ended September 30. For the nine months ended September 30, unrealized fair value changes in our derivative instruments decreased energy revenues and expenses by $83 million and $62 million respectively, and were due to decreased trading activity in the Ontario power market, and higher forward Alberta power prices combined with an increase in financial sales contracts that were not designated as hedges for accounting purposes.

- Alberta electricity margins increased for the three months and nine months ended September 30, 2007 primarily due to favourable settlements on financial sales contracts resulting from portfolio length that was sold forward in the third quarter of 2007 at higher contract prices compared with the prior year. In 2006, portfolio length was sold at spot Alberta power prices. Penalty payments received on our acquired PPAs were higher in 2007 due to higher rolling average power prices when the underlying plants incurred unplanned outages.

  These increases were partly offset by our reduced interest in the Battle River PSA. In addition, Alberta electricity margins on energy sales to RRT customers were lower in 2007 due to changes in the EPSP effective July 1, 2006. We also experienced unfavourable energy settlements associated with customer billings due to the imprecision in customer consumption data received from load settlement agents and the time lags inherent in the resettlement process. We use estimates for determining the amount of energy consumed but not yet billed. The variance is within an acceptable range and could reverse with the receipt of future resettlement information.

- Energy Services' energy revenues and expenses, excluding unrealized fair value changes, increased by $119 million and $109 million respectively, for the quarter and by $366 million and $362 million respectively, for the nine months ended September 30 compared with the prior year periods. These increases were due to more natural gas trading activities and more power trading activities in the Pacific Northwest market in 2007. Energy revenues from settlements of financial sales were higher in 2007 due to increased volume and higher contract prices. Revenues from our RRT customers were higher due to EPSP pricing. Energy expenses were higher due to increased volume of financial purchases resulting from the new EPSP and higher contract prices. These increases were partly offset by our reduced interest in the Battle River PSA and expiry of the short term tolling arrangement with Calpine Power Income Fund for operation of their Calgary Energy Centre for the period from February 16, 2006 to June 30, 2006 and the month of September 2006.

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

Water Services

Water Services results (including intersegment transactions) (Unaudited, $ millions)	**Three months ended September 30**		**Nine months ended September 30**	
	2007	**2006**	**2007**	**2006**
Revenues	$ 70	$ 56	$ 174	$ 155
Expenses	47	42	128	119
Operating income	**$ 23**	**$ 14**	**$ 46**	**$ 36**

Water sales were higher in the three and nine months ended September 30, 2007 due to increased rates as approved by the City of Edmonton. Water transportation services margins were higher in the third quarter due to an increase in streetlight construction activities for the City of Edmonton and contracting income from Distribution and Transmission's DESS project in 2007. Partly offsetting this, water treatment costs were higher due to more spring run-off and unfavourable water conditions due to wet weather in 2007.

CONSOLIDATED BALANCE SHEETS

Significant changes in consolidated assets are outlined below:

	September 30, 2007	December 31, 2006	Increase (decrease) $ millions	Explanation
Cash and cash equivalents	$ 102	$ 260	$ (158)	Refer to liquidity and capital resources section.
Accounts receivable (including income taxes recoverable)	578	647	(69)	Lower Alberta wholesale electricity settlements due to lower power prices compared with December 31, 2006, and lower Genesee PPA and Genesee 3 pool revenues.
Derivative instruments asset (current)	118	26	92	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 current assets	81	70	11	Higher inventory for planned maintenance activity.
Property, plant and equipment	4,107	3,908	199	Reflects 2007 capital expenditures partly offset by depreciation and amortization expense.
Power purchase arrangements (“PPAs”)	693	757	(64)	Sale of 10% interest in Battle River PSA and amortization of remaining PPAs in 2007.
Contract and customer rights and other intangible assets	182	207	(25)	Amortization of customer and contract rights.
Derivative instruments asset (non- current)	101	20	81	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, combined with an increase in the fair value of foreign exchange derivatives.
Future income tax asset (non-current)	149	127	22	Increase in temporary differences between accounting and tax bases of assets and liabilities resulting from implementation of new financial instruments accounting standards.
Goodwill	185	183	2	
Other assets	234	178	56	Purchase of ABCP offset by a reduction in estimated fair value.

Significant changes in consolidated liabilities and shareholder's equity are outlined below:				
	September 30, 2007	**December 31, 2006**	**Increase (decrease) $ millions**	**Explanation**
Short-term debt	$ -	$ 216	$ (216)	Reflects the repayment of Power LP's borrowing under its bridge acquisition credit facility.
Derivative instruments liability (current)	159	24	135	Reflects 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	736	608	128	Redemption of subsidiary's preferred shares on September 30 2007, which were settled in October, partly offset by lower Alberta wholesale electricity settlements due to lower power prices compared with December 31, 2006.
Other current liabilities	128	124	4	
Long-term debt (including current portion)	2,077	2,179	(102)	Ongoing scheduled debt repayments to the City of Edmonton and net reduction in Power LP's debt with the replacement of acquisition financing and lease obligations with a senior unsecured notes issue.
Derivative instruments liability (non-current)	134	27	107	Reflects 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.
Future income tax liability (non-current)	91	84	7	
Other non-current liabilities	120	127	(7)	
Non-controlling interests	783	751	32	Reflects opening adjustment upon implementation of financial instruments accounting standards attributable to non-controlling interests, non-controlling interests' share of Power LP unit offering, Power LP income less distributions, substantive enactment of the change in tax rate applicable to preferred dividends and redemption of preferred shares by subsidiary company in September 2007.
Shareholder's equity	2,302	2,243	59	Net income and adjustments to retained earnings upon implementation of financial instruments accounting standards, 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.

LIQUIDITY AND CAPITAL RESOURCES

Cash inflows (outflows) are summarized below:

	Three months ended September 30, 2007	Three months ended September 30, 2006	Increase (decrease) $ millions	Explanation
Operating	$ 150	$ 111	$ 39	Reflects change in non-cash operating working capital, primarily fewer payments for Alberta wholesale electricity due to the timing of the electricity settlements.
Investing	(204)	(37)	(167)	Reflects higher capital expenditures, primarily the Keephills 3 and Clover Bar generation projects, the EL Smith water treatment plant expansion, and the DESS project. Also reflects the purchase of ABCP.
Financing	10	(80)	90	Net financing inflows in 2007 reflect proceeds from a private placement of senior unsecured notes by Power LP, used to repay capital lease obligations and amounts borrowed for the Frederickson and PEV acquisitions, whereas 2006 financing net outlays reflect repayment of US long term financing partly offset by equity issued by Power LP to non-controlling interests.

	Nine months ended September 30, 2007	Nine months ended September 30, 2006	Increase (decrease) $ millions	Explanation
Operating	$ 351	$ 443	$ (92)	Reflects change in non-cash operating working capital, primarily due to increased payments of liabilities including higher employee short-term incentive payments in 2007 and higher working capital requirements for the PEV operations. Also reflects change in other non-current items, primarily loans advanced to Battle River Syndicate members in 2007 and lower PPA availability incentive payments received in 2007 compared with 2006.
Investing	(319)	152	(471)	Reflects sale of a smaller interest in Battle River PSA and higher capital expenditures in 2007, primarily the Keephills 3 and Clover Bar generation projects, the EL Smith water treatment plant expansion and the DESS project. Also reflects the purchase of ABCP.
Financing	(190)	(406)	216	Net financing outlays in 2007 included the repayment of Power LP's borrowing under its bridge acquisition credit facility, partly offset by the issuance of preferred shares by a Power LP subsidiary in the second quarter and the placement of senior unsecured notes in the third quarter, whereas 2006 financing outlays were marked by the redemption of preferred shares by a subsidiary.

The Company has issued letters of credit for $380 million (December 31, 2006 - $248 million) to meet the credit requirements of energy market participants, to meet conditions of certain debt and service agreements, and to satisfy legislated reclamation requirements.

CONTRACTUAL OBLIGATIONS

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%.

On August 24, 2007, a subsidiary of the Company paid off its capital lease obligations for the Naval Station, North Island and Naval Training Centers for $72 million (US$68 million). The $1 million difference between the purchase price and the carrying amount of the lease obligation has been recorded as an increase in the cost of the acquired property, plant and equipment.

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

During the quarter, the Company drew $29 million on its $400 million five-year extendible syndicated bank revolving credit facility. The amounts outstanding under this facility mature within one year of the balance sheet date and bear interest at 5.01%.

During the quarter, the Company drew $35 million on its $400 million unsecured two-year credit facilities. The amounts outstanding under these facilities mature within one year of the balance sheet date and bear interest at a weighted average interest rate of 4.81%.

During the quarter, the Company drew $11 million on its $300 million unsecured three-year Power LP revolving extendible credit facilities. The amounts outstanding under these facilities mature within one year of the balance sheet date and bear interest at 4.77%.

There have been no other material changes to the Company's purchase obligations during the third quarter, including payments for the next five years and thereafter. For further information on these obligations, refer to the 2006 annual MD&A.

CHANGES IN ACCOUNTING STANDARDS

Accounting changes for 2007

As described in EPCOR's most recent annual MD&A, the Company has adopted accounting policies in accordance with the following new accounting standards.

Financial instruments, hedges and comprehensive income

On January 1, 2007, we adopted the Canadian Institute of Chartered Accountants' new accounting standards "Financial Instruments - Recognition and Measurement", "Financial Instruments – Disclosure and Presentation, "Hedges", and "Comprehensive Income".

As required by the new accounting standards, our comparative interim financial statements have not been restated, except to reclassify the 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.

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 unrealized foreign exchange gains and losses arising from the translation of self-sustaining foreign operations, the effective portion of the changes in the fair value of derivative instruments used in cash flow hedges of electricity sales and purchases and of anticipated foreign currency cash flows, and changes in the fair value of assets available for sale. 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 this new statement is recorded net of income taxes. Accumulated other comprehensive income is a new component of shareholder's equity.

Financial instruments

In accordance with the new accounting standard, we classify our cash and 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 financial 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 September 30, 2007 are summarized as follows:

	Carrying value					
	Held for trading	Available for sale	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets	$ 67	$ 19	$ 91	$ -	$ 177	$ 180
Long-term debt (including current portion)	-	-	-	2,077	2,077	2,261

In accordance with the standard, we have reclassified $15 million of debt issue costs from other assets to long-term debt effective January 1, 2007 and amortized them using the effective interest method. Previously, debt issue costs were amortized on a straight-line basis over the life of the associated debt. Also, in accordance with the new accounting standard, we expense any transaction costs related to financial instruments classified as held for trading.

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:

	Energy		Foreign exchange	Interest rate	
	Hedges	Non-hedges	Non-hedges	Non-hedges	Total
Total derivative instruments net asset (liability) as at September 30, 2007	$ (108)	$ 7	$ 27	$ -	$ (74)
Total derivative instruments net asset (liability) as at December 31, 2006	-	(11)	5	1	(5)

At September 30, 2007, the net fair value of financial derivative instruments specifically designated and qualifying for hedge accounting was a liability of $108 million and is included in derivative instruments asset and derivative instruments liability in 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.

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, but are 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 asset of $96 million, an increase in non-controlling interests of $66 million, an increase in future income tax liability 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 asset by $45 million and derivative instruments liability by $45 million.

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

At September 30, 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 due to increases in the forward Alberta electricity prices relative to the contract prices, which was partly offset by the unrealized gain on our natural gas supply contracts due to increases in forward natural gas prices relative to the contract prices.

For the nine months ended September 30, 2007, the fair value of our forward foreign currency contracts increased, resulting in unrealized gains. This was due to the impact of a strengthening Canadian dollar in the current year on foreign currency sales contracts used to hedge US denominated revenues. This was partly offset by higher unrealized losses on foreign currency purchase contracts used to hedge anticipated US dollar denominated purchases in 2007. The weighted average fixed exchange rate for contracts outstanding at September 30, 2007 was $US 0.90 (December 31, 2006, $US 0.88) for every Canadian dollar.

Other Comprehensive Income

As of January 1, 2007, the changes in the fair value of the effective 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. Historically, 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 asset and liability in the consolidated balance sheet.

For the nine months ended September 30, 2007, a cumulative loss, net of income taxes, of $59 million was recorded in other comprehensive income for the effective portion of cash flow hedges, and an unrealized loss, net of income taxes, of $25 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 $74 million in net losses recorded in accumulated other comprehensive income, net losses of $39 million (net of taxes of $17 million) related to derivative instruments designated as cash flow hedges at September 30, 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. The shares held are not typically traded on an exchange and therefore can be difficult to value. During the nine months ended September 30, 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. We have considered the effect of illiquidity and the restrictions on the shares held in determining its fair value.

Future accounting changes

Effective January 1, 2008, the new CICA Handbook Section 3031 “Inventories” will replace existing Section 3030 “Inventories” to be consistent with the International Accounting Standard for inventories. 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, which could be the best available measure for net realizable value. We are assessing the impact, if any, of the new standard.

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 disclosures on the Company's management of capital and on the risks associated with financial instruments. The Company is currently reviewing the impact of these new standards on its financial statements.

CRITICAL ACCOUNTING ESTIMATES

Implementation of the new accounting standard on financial instruments in 2007 has required us to record more of these instruments at fair value than in the past, which involves a greater use of estimates. The most significant item requiring fair valuation under the new standard was Power LP's natural gas supply contracts for its Ontario plants. These valuations reflect management's best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of futures prices and foreign exchange rates, time value, credit risk, estimated recovery periods and volatility. In illiquid or inactive markets, we use appropriate price modeling to estimate fair value. It is possible that the assumptions used in establishing fair value amounts will differ from actual prices and the impact of such variations could be material.

RISK MANAGEMENT

This section should be read in conjunction with the Risk Management section of the most recent annual MD&A. EPCOR faces a number of risks including electricity price and volume risk, natural gas price and volume risk, operational risk, government and regulatory risk, supply risk of acquired PPAs, credit risk, environmental risk, project risk, availability of people risk, weather risk, foreign exchange risk, conflicts of interest risk, and general economic conditions and business environment risks. The Company employs active programs to manage these risks.

Environmental risk

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 both EPCOR and AERI will contribute equal amounts. 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"). 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 1, 2 and 3 generating stations, and the Sundance 5 and 6 units which are subject to PPAs acquired by EPCOR, 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. The Alberta Government will recognize three mechanisms for compliance with this regulation: (1) operational or plant changes to reduce emission intensity, (2) submission of greenhouse gas emission reduction offsets which are sourced from within Alberta, and (3) investment in a new Alberta technology fund at $15 per tonne of required CO2E reduction. 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 should be recoverable from the PPA holder under the terms of the PPA. These costs have been estimated at approximately $11 million per year. EPCOR's Genesee 3 unit is considered a new unit under the Regulation and will receive a "three-year grace period", after which time 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 reducing interest in the Battle River PPA is $1 million, $2 million and $2 million for the years 2007, 2008 and 2009, respectively. In 2007, EPCOR has recorded $2 million for the cost associated with this regulation.

On April 26, 2007, the Canadian Environment Minister announced a new regulatory framework to reduce greenhouse gas emissions and air pollution in Canada. The Canadian government has set targets of a 20% absolute reduction in greenhouse gases from 2006 levels by 2020 and a 50% reduction in air pollution by 2015. The Company is an emitter of carbon dioxide (a greenhouse gas), nitrogen oxide and sulphur dioxide which are all targeted for reduction under the proposed new legislation. The operational and financial impact to the Company of the new regulatory framework cannot be determined until further details are announced, including the definition of the clean air fuel standard and how such costs will be allocated among producers and consumers and whether the provincial and federal regulatory regimes will be harmonized.

The Company complies, in all material respects, with current federal, provincial, state and local environmental legislation and guidelines.

Availability of people

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.

Government and regulatory risk

In the second quarter of 2007, tax legislation included in Bill C-52, the Budget Implementation Act, 2007 (the "Bill), was substantively enacted and will result in changes to the manner in which certain publicly traded trust and partnerships, such as Power LP, are taxed. Substantive enactment of the Bill resulted in the recognition of future income tax amounts based on estimated net taxable temporary differences that will reverse after 2010, but it was not material at a consolidated level.

On October 30, 2007, the Minister of Finance (Canada) announced proposed tax measures including corporate income tax rate reductions. If these measures become law, EPCOR will record a net charge to income tax expense reflecting a reduction in EPCOR's recorded future income tax assets and liabilities resulting from the reduced income tax rates. This reduction is estimated to be in the range of $5 million to $10 milllion. In addition, if the measures become law, income tax payments will be lower than they otherwise would be in future years.

Asset backed commercial paper

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.

As part of its ongoing risk management practices, the Company reviews current and proposed transactions to consider their impact on the risk profile of the Company. There have been no other material changes to the risk profile or risk management strategies of EPCOR as described in the annual MD&A for 2006.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

There were no changes in the Company’s internal controls over financial reporting during the interim period ended September 30, 2007 that have materially affected, or are reasonably likely to materially affect the Company’s internal control over financial reporting.

OUTLOOK

Excluding the gain on sale of the interest in the Battle River PSA and the impact of fair value changes, earnings are expected to be slightly lower for the final quarter than the average for the first three quarters, in part due to normal seasonal variances and plant maintenance activities. The implementation of the new accounting standard on financial instruments is expected to increase the volatility of our earnings, which may not be representative of the performance of the underlying business and has no impact on our cash flows.

QUARTERLY RESULTS

Quarter ended	Revenues	Net income from continuing operations	Net income (loss) from discontinued operations	Net income
		(Unaudited, $ millions)		
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
December 31, 2005	866	46	(9)	37

Events for 2007, 2006 and 2005 quarters that have significantly impacted net income from continuing operations, net income and the comparability between quarters are:

- 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 $30 million gain from the sale of a 10% interest in the Battle River PSA, an $11 million 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 electricity 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 increasing forward market 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 Power Income Fund, higher generation incentive income and realized gains on foreign exchange forward contracts.
- September 30, 2006 third quarter results include a net income increase from discontinued operations of $10 million 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 PSA and related transactions which contributed $327 million to net income. 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 a $10 million 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. These tax adjustments reduced net income by $16 million.
- 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 of $117 million. In addition, unrealized fair value changes in derivative financial instruments increased net income by $14 million.
- December 31, 2005 fourth quarter results include the impact of reduced Alberta electricity margins as margins on new and renewed electricity contracts decreased.

Additional information

Additional information relating to EPCOR is available on SEDAR at www.sedar.com.

EPCOR UTILITIES INC.
Consolidated Statements of Income
(Unaudited, in millions of dollars)

	Three months ended September 30		Nine months ended September 30	
	2007	2006	2007	2006
Revenues	$ 930	$ 702	$ 2,694	$ 2,203
Operating expenses (income):				
Energy purchases	475	368	1,469	1,156
Fuel	122	34	281	94
Operations, maintenance and administration	125	108	352	318
Franchise fee, property taxes and other taxes	17	18	49	49
Depreciation, amortization, and asset retirement accretion (note 7)	76	58	202	172
Foreign exchange (gain) loss	(17)	8	(39)	(6)
	798	594	2,314	1,783
	132	108	380	420
Gain on sale of power purchase arrangement and related transactions (note 6)	-	-	34	378
Income before financing expenses	132	108	414	798
Financing expenses	47	37	122	112
Income from continuing operations before income taxes and amounts in lieu of income taxes and non-controlling interests	85	71	292	686
Income taxes and amounts in lieu of income taxes (note 10)	26	13	30	1
Income from continuing operations before non-controlling interests	59	58	262	685
Non-controlling interests (note 12)	(8)	11	44	69
Net income from continuing operations	67	47	218	616
Net income from discontinued operations	-	9	-	9
Net income	$ 67	$ 56	$ 218	$ 625

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.
Consolidated Balance Sheets
(Unaudited, in millions of dollars)

	September 30, 2007	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 102	$ 260
Accounts receivable	567	646
Income taxes recoverable	11	1
Inventories	64	57
Prepaid expenses	16	12
Derivative instruments asset (note 5)	118	26
Future income tax asset	1	1
	879	1,003
Property, plant and equipment	4,107	3,908
Power purchase arrangements	693	757
Contract and customer rights and other intangible assets (note 7)	182	207
Derivative instruments asset (note 5)	101	20
Future income tax asset	149	127
Goodwill	185	183
Other assets (note 8)	234	178
	$ 6,530	$ 6,383
Liabilities and Shareholder's Equity		
Current liabilities:		
Short-term debt	$ -	$ 216
Accounts payable and accrued liabilities	736	608
Income taxes payable	67	19
Derivative instruments liability (note 5)	159	24
Other current liabilities	17	13
Future income tax liability	44	92
Current portion of long-term debt	308	63
	1,331	1,035
Long-term debt	1,769	2,116
Derivative instruments liability (note 5)	134	27
Other non-current liabilities	120	127
Future income tax liability	91	84
	3,445	3,389
Non-controlling interests (note 12)	783	751
Shareholder's equity	2,302	2,243
Contingencies (note 14)		
	$ 6,530	$ 6,383

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.
Consolidated Statements of Changes in Shareholder's Equity
(Unaudited, in millions of dollars)

	Three months ended September 30		Nine months ended September 30	
	2007	2006	2007	2006
Retained earnings:				
Balance, beginning of period	$ 2,337	$ 2,229	$ 2,245	$ 1,765
Adjustment for changes in accounting policies (note 4)	-	-	12	-
Net income	67	56	218	625
Common share dividends paid	(32)	(31)	(96)	(94)
Refundable taxes	-	-	(7)	(42)
Balance, end of period	2,372	2,254	2,372	2,254
Accumulated other comprehensive loss:				
Balance, beginning of period	(46)	(8)	(2)	(8)
Adjustment for changes in accounting policies (note 4)	-	-	(41)	-
Other comprehensive income (loss)	(24)	6	(27)	6
Balance, end of period	(70)	(2)	(70)	(2)
Total shareholder's equity, end of period	$ 2,302	$ 2,252	$ 2,302	$ 2,252

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.
Consolidated Statements of Comprehensive Income
(Unaudited, in millions of dollars)

	Three months ended September 30		Nine months ended September 30	
	2007	2006	2007	2006
Net income	$ 67	$ 56	$ 218	$ 625
Other comprehensive income (loss), net of income taxes:				
Unrealized losses on derivative instruments designated as cash flow hedges [1]	(19)	-	(59)	-
Reclassification of losses on derivative instruments designated as cash flow hedges to net income [2]	(4)	-	25	-
Unrealized gains on financial instruments designated as available for sale [3]	-	-	9	-
Unrealized loss in self-sustaining foreign operations [4]	(1)	6	(2)	6
	(24)	6	(27)	6
Comprehensive income	$ 43	$ 62	$ 191	$ 631

(1) For the three and nine months ended September 30, 2007, net of income tax recovery of $10 and $27, respectively.
(2) For the three and nine months ended September 30, 2007, net of income tax expense of nil and $13, respectively.
(3) For the three and nine months ended September 30, 2007, net of income tax expense of nil and $2, respectively.
(4) For the three and nine months ended September 30, 2007 and September 30, 2006, net of income tax expense of nil.

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.
Consolidated Statements of Cash Flows
(Unaudited, in millions of dollars)

	Three months ended September 30		Nine months ended September 30	
	2007	2006	2007	2006
Operating activities:				
Net income	$ 67	$ 56	$ 218	$ 625
Items not affecting cash:				
Depreciation, amortization, and asset retirement accretion	76	58	202	172
Gain on sale of power purchase arrangement and related transactions (note 6)	-	-	(34)	(378)
Reduction of Clover Bar asset retirement obligations	-	(15)	-	(15)
Non-controlling interests in EPCOR Power L.P. (note 12)	(15)	8	38	54
Fair value changes on derivative instruments	19	-	50	-
Other non-cash items	(17)	6	(74)	(42)
Future income taxes and amounts in lieu of income taxes	17	8	8	(6)
	147	121	408	410
Change in other non-current items	(7)	16	(18)	22
Net change in non-cash operating working capital	10	(26)	(39)	11
	150	111	351	443
Investing activities:				
Property, plant, equipment and other assets	(146)	(59)	(331)	(145)
Net change in non-cash working capital	13	(3)	24	(9)
Third party asset backed commercial paper (note 8)	(71)	-	(71)	-
Proceeds on sale of Battle River PSA interest (note 6)	-	-	59	336
Proceeds on sale of Sundance PSA interest	-	-	-	17
Purchase of interest in Battle River PSA	-	-	-	(52)
Purchase and conversion of subscription receipts	-	25	-	-
Net business acquisitions and disposals	-	-	-	5
	(204)	(37)	(319)	152
Financing activities:				
Issue (redemption) of subsidiary preferred shares (note 11)	-	-	121	(150)
Increase (decrease) in short-term debt	-	31	(200)	3
Proceeds from long-term debt (note 9)	314	-	314	210
Principal payments on long-term debt	(249)	(112)	(331)	(366)
Distributions to non-controlling interests	(23)	(23)	(67)	(64)
Issue of limited partnership units of EPCOR Power L.P. to non-controlling interests (note 12)	-	55	69	55
Common share dividends paid	(32)	(31)	(96)	(94)
	10	(80)	(190)	(406)
Increase (decrease) in cash and cash equivalents	(44)	(6)	(158)	189
Cash and cash equivalents, beginning of period	146	285	260	90
Cash and cash equivalents, end of period	$ 102	$ 279	$ 102	$ 279
Supplemental cash flow information:				
Interest paid	$ 28	$ 32	$ 117	$ 112
Income taxes paid net of income taxes recovered	3	(9)	24	(1)

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.
Notes to the Interim Consolidated Financial Statements
September 30, 2007
(Unaudited, in millions of dollars)

1. Basis of presentation:

These unaudited interim consolidated financial statements of EPCOR Utilities Inc. ("the Company" or "EPCOR") have been prepared in accordance with Canadian generally accepted accounting principles for interim financial statements and do not include all of the disclosures normally found in the Company's annual consolidated financial statements. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2006.

These financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent annual financial statements except for the changes in accounting policies as described in note 4.

2. Nature of operations:

Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and water, changes in energy prices and the timing and recognition of regulatory decisions. Consequently, interim results are not necessarily indicative of annual results.

3. Measurement uncertainty:

In accordance with Canadian generally accepted accounting principles, the Company uses estimates in preparing its consolidated financial statements. Interim consolidated financial statements necessarily employ a greater use of estimates than the annual consolidated financial statements.

4. Changes in accounting policies:

Commencing January 1, 2007, the Company 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, the comparative interim 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. They have been reclassified from the cumulative translation adjustment account to accumulated other comprehensive income, both within shareholder's equity.

4. Changes in accounting policies (continued):

Comprehensive income and equity

These new standards establish requirements for the reporting and presentation of comprehensive income which is composed of net income and other comprehensive income and for the presentation of equity and changes in equity due to the comprehensive income requirements. Other comprehensive income includes unrealized gains or losses arising from the translation of net investments in self-sustaining foreign operations, the changes in the fair value of the effective portion of derivative instruments used in cash flow hedges and unrealized gains and losses on financial instruments designated as available for sale. 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 identified and classified as either available-for-sale, held for trading, held-to-maturity or loans and receivables. Financial liabilities are classified as either held for trading or other. 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.

Financial assets and financial liabilities held for trading are measured at fair value with the changes in fair value reported in earnings. Financial assets held to maturity, loans and receivables and financial liabilities other than those held for trading are measured at amortized cost. Available-for-sale financial assets are measured at fair value with changes in fair value reported in other comprehensive income until the financial asset is disposed of, or becomes impaired.

Transaction costs related to long-term debt are capitalized and amortized over the expected life of the instrument utilizing the effective interest method. Previously, these costs were deferred and amortized on a straight-line basis over the term of the debt. The effective interest method calculates the amortized cost of this financial liability and allocates the interest expense over the term of the debt using an effective interest rate.

All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments asset and derivative instruments liability unless exempted from derivative treatment as an expected purchase, sale or usage. All changes in their fair value are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income. The Company chose a transition date of January 1, 2003 for embedded derivatives and therefore will only be required to account separately for those embedded derivatives in any hybrid instruments issued, acquired or substantively modified after that date.

4. Changes in accounting policies (continued):

Hedges

The hedging standards specify the criteria that must be met in order for hedge accounting to be applied. Hedge accounting enables the recording of gains, losses, revenues and expenses from derivative instruments in the same period as those related to the hedged item. Hedge accounting may be applied for fair value hedges, cash flow hedges and hedges of foreign currency exposures of net investments in self-sustaining foreign operations if the criteria are met. These standards also specify that hedge accounting is discontinued when the hedge is no longer determined to be effective, the hedging item is sold or terminated, or upon the sale or early termination of the hedged item.

Financial statement impact

Certain physical fuel purchase contracts are not designated as contracts used in accordance with our expected purchase requirements and, therefore, are measured at fair value. An opening adjustment to retained earnings to reflect the fair value of these contracts at January 1, 2007 has been recorded. Subsequent changes in the fair value of these contracts are reported in net income.

Qualifying cash flow hedges of electricity and natural gas sales and purchases have been established and the changes in the fair value of the effective portion of the associated derivative instruments have been reflected as an opening adjustment to accumulated other comprehensive income with subsequent changes to the effective portion included in other comprehensive income. The changes in the fair value of the ineffective portion of these derivatives are included in net income.

Prior to the adoption of these new standards, the unrealized losses on certain financial instruments which did not satisfy all the required conditions for hedge accounting were recorded as a derivative instruments asset in the balance sheet. As required by the new standards, these unrealized losses were reclassified to opening retained earnings.

Also prior to the adoption of these new standards, the unrealized gains associated with discontinued hedges were included in derivative instruments liability in the balance sheet. These gains were recognized in net income on the same basis as the net income recognition of the related hedged item. Consistent with the requirements of the new standards, these unrealized gains were reclassified to accumulated other comprehensive income as a cumulative opening adjustment.

(Unaudited, in millions of dollars)

4. Changes in accounting policies (continued):

On January 1, 2007, the Company made the following adjustments to the balance sheet to adopt the new standards:

Description	**Balance sheet item**	**Increase (decrease) $millions**
Physical power and natural gas purchase and sales contracts measured at fair value	Derivative instruments asset – current	$ 47
	Derivative instruments asset – non-current	94
	Derivative instruments liability – current	18
	Derivative instruments liability – non-current	27
	Future income tax liability – current and non-current	10
	Non-controlling interests	66
	Opening retained earnings	20
Deferred unrealized losses relating to financial instruments not qualifying as hedges	Derivative instruments asset –non-current	(12)
	Future income tax asset – non-current	4
	Opening retained earnings	(8)
Cash flow hedges measured at fair value	Derivative instruments asset – current	59
	Derivative instruments asset – non-current	32
	Future income tax asset – non-current	18
	Derivative instruments liability – current	71
	Derivative instruments liability – non-current	80
	Opening accumulated other comprehensive loss	(42)
Deferred unrealized gains relating to certain previously discontinued hedges reclassified to accumulated other comprehensive income	Derivative instruments liability –non-current	(6)
	Future income tax liability – current and non-current	1
	Non-controlling interests	4
	Opening accumulated other comprehensive loss	1
Deferred financing costs reclassified from other assets to long-term debt	Other assets	(15)
	Long-term debt	(15)

(Unaudited, in millions of dollars)

4. Changes in accounting policies (continued):

During the three and nine month periods ended September 30, 2007, the new financial instruments accounting standards impacted the financial statements as follows:

	Increase (decrease) $millions	
Financial statement line item	Three months ended September 30, 2007	Nine months ended September 30, 2007
Derivative instruments asset – current and non-current	$ (100)	$ (79)
Future income tax asset	10	15
Other assets	(4)	6
Derivative instruments liability – current and non-current	(15)	34
Future income tax liability	(6)	(4)
Non-controlling interests (balance sheet)	(36)	(47)
Revenues	-	3
Fuel expense	52	68
Financing expenses (note 8)	4	4
Income tax expense (reduction)	(6)	(6)
Non-controlling interests (statement of income)	(36)	(47)
Other comprehensive income (loss)	(23)	(25)

Future accounting changes

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 disclosures on the Company’s management of capital and on the risks associated with financial instruments. The Company is currently reviewing the impact of these new standards on its financial statements.

Effective January 1, 2008, the new CICA Handbook Section 3031 “Inventories” will replace existing Section 3030 “Inventories” to be consistent with the International Accounting Standard for inventories. 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, which could be the best available measure for net realizable value. We are assessing the impact, if any, of the new standard.

(Unaudited, in millions of dollars)

5. Financial instruments:

The Company classifies its cash and cash equivalents and current and non-current derivative instruments assets and liabilities as held for trading and measures them at fair value. Accounts receivable are classified as loans and receivables and accounts payable and accrued liabilities are classified as other financial 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 the Company's other financial instruments at September 30, 2007 are summarized as follows:

	Carrying value					
	Held for trading	Available for sale	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets (note 8)	$ 67	$ 19	$ 91	$ -	$ 177	$ 180
Long-term debt (including current portion)	-	-	-	2,077	2,077	2,261

Fair values of financial instruments are determined based on exchange or over-the counter quotations. Fair value amounts reflect management's best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of futures prices and foreign exchange rates, time value and volatility. In illiquid or inactive markets, the Company uses appropriate price modeling, such as option pricing models and discounted cash flow analysis, using observable market-based inputs to estimate fair value. It is possible that the assumptions used in establishing fair value amounts will differ from actual prices and the impact of such variations could be material.

At December 31, 2006, the fair values of off-balance sheet contracts-for-differences were disclosed but were not included in the balance sheet.

Risk management and hedging activities

The Company is exposed to changes in energy commodity prices, foreign currency exchange rates and interest rates. The Company uses various risk management techniques including derivative instruments to reduce its exposure. Derivative instruments include forward contracts, fixed-for-floating swaps, and option contracts. Such contracts may be used to establish a fixed price for an energy commodity, an interest bearing obligation, or an obligation denominated in a foreign currency. When the requirements are met and the derivative is highly effective, the Company uses hedge accounting for offsetting the changes in cash flows attributable to the hedged risk.

(Unaudited, in millions of dollars)

5. Financial instruments (continued):

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

	September 30, 2007				
	Energy		Foreign exchange	Interest rate	
	Hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 43	$ 63	$ 12	$ -	$ 118
Non-current	27	47	27	-	101
Derivative instruments liabilities:					
Current	(100)	(50)	(9)	-	(159)
Non-current	(78)	(53)	(3)	-	(134)
	$ (108)	$ 7	$ 27	$ -	$ (74)

	December 31, 2006				
	Energy		Foreign exchange	Interest rate	
	Hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ -	$ 13	$ 12	$ 1	$ 26
Non-current	-	14	6	-	20
Derivative instruments liabilities:					
Current	-	(23)	(1)	-	(24)
Non-current	-	(15)	(12)	-	(27)
	$ -	$ (11)	$ 5	$ 1	$ (5)

If hedge accounting requirements are not met, unrealized and realized gains and losses on the energy derivatives are recorded in energy revenues, energy purchases or cost of fuel, as appropriate.

Of the $74 million in net losses recorded in accumulated other comprehensive income, net losses of $39 million (net of taxes of $17 million) related to derivative instruments designated as cash flow hedges at September 30, 2007 are expected to settle and be reclassified to net income over the next twelve months.

(Unaudited, in millions of dollars)

6. Sale of power syndicate agreement:

During the first quarter of 2007, 10% of the Battle River Power Syndicate Agreement ("Battle River PSA") was sold. This transaction was incremental to the initial sale of 55% of the Battle River PSA that was reported during the prior year. The current year's transaction is summarized as follows:

Cash proceeds from sale	$	59
Less net book value and costs of disposal		25
Gain on sale before income taxes		34
Less future income taxes		4
Gain on sale after income taxes	$	30

7. Asset impairment charge:

Changes in the outlook for incentives that were expected to be earned under the management agreement between a subsidiary of the Company and Primary Energy Recycling Holdings LLC ("PERH"), Primary Energy Operations LLC and Primary Energy Recycling Corporation ("PERC") based on expected future cash distributions from PERH resulted in the determination that the full book value of this management agreement was unlikely to be recovered from future cash flows. As a result, the Company wrote down this asset to its estimated fair value and recorded a $13 million pre-tax impairment charge to depreciation, amortization and asset retirement accretion. The asset was previously recorded in Contract and customer rights and other intangibles in the Generation segment.

8. Other assets:

		September 30, 2007		December 31, 2006
Carrying value				
Third party asset backed commercial paper	$	67	$	-
Loans and other long-term receivables		62		56
Investment in PERH		52		57
Net investment in lease		29		35
Debenture issue expenses		-		22
Portfolio investments		19		9
Deferred charges		6		7
		235		186
Accumulated amortization				
Debenture issue expenses		-		7
Deferred charges		1		1
		1		8
	$	234	$	178

8. Other assets (continued):

At September 30, 2007, the Company held $67 million in Canadian third party asset backed commercial paper ("ABCP"), all of which was purchased during the third quarter. The Company's ABCP has been directly impacted by the current liquidity issues affecting that segment of the commercial paper market and as a result, all of the Company's ABCP matured with no payment of principal, accrued interest or roll over. All of the trusts in which the Company's ABCP investments are held are rated R-1 (high) by DBRS Limited ("DBRS"), which is their highest rating for commercial paper. DBRS has placed these trusts "Under Review with Developing Implications" following an announcement on August 16, 2007 that a consortium representing banks, asset providers and major investors had agreed in principle to a long-term proposal and interim arrangements regarding the ABCP ("the Montreal Accord"). Under this proposal, 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"). On October 15, 2007, the standstill arrangements of the Montreal Accord were extended to December 14, 2007.

Due to the uncertainties associated with the timing of repayment, the ABCP investment is classified as non-current under 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 reduction in fair value of $4 million during the third quarter, representing the difference between the original purchase price of $71 million and the estimated fair value of $67 million at September 30, 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 downgrades of the applicable ABCP issuing trusts, observable interest rates and credit spreads for estimating future interest payments and applicable discount rates, estimated recovery periods based on the estimated lives of the underlying assets of the issuing trusts, and ranges of recoverability based on publicly available default statistics for 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 and the quality and tenor of the underlying assets and instruments in the applicable trusts. Accordingly, the estimate of fair value of ABCP may change materially as events unfold and more information becomes available.

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.

(Unaudited, in millions of dollars)

9. Long-term debt and other non-current liabilities:

On August 15, 2007, a subsidiary of the Company 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%.

On August 24, 2007, a subsidiary of the Company paid off its capital lease obligations for the Naval Station, North Island and Naval Training Centers for $72 million (US$68 million). The $1 million difference between the purchase price and the carrying amount of the lease obligation has been recorded as an increase in the cost of the acquired property, plant and equipment.

The proceeds from the private placement were used to repay the capital lease obligations as well as to repay amounts initially borrowed as part of the Frederickson power plant and Primary Energy Ventures LLC ("PEV") acquisitions.

During the quarter, the Company drew $29 million on its $400 million five-year extendible syndicated bank revolving credit facility. The amounts outstanding under this facility mature within one year of the balance sheet date and bear interest at 5.01%.

During the quarter, the Company drew $35 million on its $400 million unsecured two-year credit facilities. The amounts outstanding under these facilities mature within one year of the balance sheet date and bear interest at a weighted average interest rate of 4.81%.

During the quarter, the Company drew $11 million on its $300 million unsecured three-year EPCOR Power L.P. ("Power LP") revolving extendible credit facilities. The amounts outstanding under these facilities mature within one year of the balance sheet date and bear interest at 4.77%.

10. Income taxes and amounts in lieu of income taxes:

	Three months ended September 30		Nine months ended September 30	
	2007	2006	2007	2006
Current income taxes and amounts in lieu of income taxes	$ 7	$ (3)	$ 73	$ 11
Future income taxes and amounts in lieu of income taxes	19	16	(43)	(10)
	$ 26	$ 13	$ 30	$ 1

(Unaudited, in millions of dollars)

10. Income taxes and amounts in lieu of income taxes (continued):

Income taxes and amounts in lieu of income taxes consists of:

	Three months ended September 30		Nine months ended September 30	
	2007	2006	2007	2006
Income taxes and amounts in lieu of income taxes on income from continuing operations for the period	$ 26	$ 13	$ 35	$ 51
Income taxes arising on sale of power purchase arrangement and related transactions	-	-	4	51
Corporate income tax rate reductions	-	-	1	16
Reduction of income taxes resulting from corporate restructuring within the Energy Services segment	-	-	(10)	-
Reduction of income taxes resulting from corporate restructuring within the Generation segment	-	-	-	(117)
	$ 26	$ 13	$ 30	$ 1

Corporate restructuring

On January 1, 2007, the Company reorganized certain subsidiaries within its Energy Services segment. As a result of the reorganization, the Company recognized future income tax assets of $10 million and a corresponding increase in consolidated net income. The resulting future income tax assets will be reduced over time, as the underlying income tax deductions are utilized to reduce taxable income.

On January 3, 2006, the Company reorganized certain subsidiaries within its Generation segment. As a result, the Company recognized an increase in non-current future income tax assets in the Company's consolidated balance sheet, with a corresponding income statement reduction of income taxes of $117 million.

(Unaudited, in millions of dollars)

11. Preferred shares of subsidiary companies:

Effective September 30, 2007, EPCOR Preferred Equity Inc., a subsidiary of the Company, redeemed 8 million Cumulative Redeemable Perpetual First Preferred Shares, Series I ("Preferred Shares") at par for $200 million. The Preferred Shares were issued on September 27, 2002. The redemption was completed on October 1, 2007 and funded from cash balances and debt.

The carrying value of the Preferred Shares prior to their redemption by the Company 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 between the redemption price and the carrying value has been charged to non-controlling interests in the consolidated statements of income.

In the second quarter of 2007, EPCOR Power Equity Ltd. ("EPEL"), a subsidiary of Power LP issued 5 million of 4.85% cumulative, redeemable First Preference Shares, Series 1 priced at $25.00 per share with dividends payable on a quarterly basis at the annual rate of $1.2125 per share. Proceeds of $121 million, net of share issue costs of $4 million, were used to repay amounts outstanding under the Power LP bridge acquisition credit facility, due in October 2007, incurred in conjunction with the acquisition of PEV in November 2006. Future income tax assets of $1 million on the share issue costs are recorded in the preferred share balance. On or after June 30, 2012, the shares are redeemable by EPEL at $26.00 per share, declining by $0.25 each year to $25.00 per share after June 30, 2016. The shares are not retractable by the holders.

12. Non-controlling interests:

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

	Three months ended September 30		Nine months ended September 30	
	2007	2006	2007	2006
Non-controlling interests in Power LP	$ (15)	$ 8	$ 38	$ 54
Preferred share dividends paid by subsidiary companies net of dividend taxes recovered	4	3	3	14
Preferred share issue costs recognized on redemption of preferred shares (note 11)	3	-	3	1
	$ (8)	$ 11	$ 44	$ 69

(Unaudited, in millions of dollars)

12. Non-controlling interests (continued):

Non-controlling interests reflected in the consolidated balance sheets consisted of:

	September 30, 2007	December 31, 2006
Non-controlling interests in Power LP, beginning of year	$ 554	$ 542
Partnership units issued to non-controlling interests	69	55
Earnings attributable to non-controlling interests	38	43
Other comprehensive income attributable to non-controlling interests	2	-
Opening retained earnings adjustment on implementation of financial instruments standards attributable to non-controlling interests	67	-
Distributions to non-controlling interests	(69)	(86)
Non-controlling interests in Power LP, end of period	661	554
Preferred shares issued by subsidiary companies, beginning of year	197	346
Preferred shares issued by subsidiary company (note 11)	122	-
Redemption of preferred shares by subsidiary company (note 11)	(197)	(149)
Preferred shares issued by subsidiary companies, end of period	122	197
	$ 783	$ 751

13. Guarantees:

The Company has issued letters of credit for $380 million (December 31, 2006 - $248 million) to meet the credit requirements of energy market participants, to meet conditions of certain debt and service agreements, and to satisfy legislated reclamation requirements.

14. Contingencies:

A settlement agreement has been reached with Devon Canada Corporation in respect of its claim of frustration of the contract pursuant to which it supplies gas to Power LP at the Tunis, Ontario plant. No settlement has yet been reached in respect of a separate but similar claim by NAL Resources Ltd. The Power LP has accrued for expected additional payments and has incorporated anticipated increases in fuel supply prices into the determination of the fair value of derivative instruments at September 30, 2007.

15. Segment disclosures:

The Company operates in the following reportable business segments, which follow the organization, management and reporting structure within the Company.

Generation

Generation is involved in the development and operation of rate-regulated and non-rate-regulated electrical generation plants within Alberta, British Columbia, Ontario, and in the United States in Washington, Colorado, New York, New Jersey, California and North Carolina.

Distribution and Transmission

Distribution and Transmission is involved in the transmission and distribution of electricity within The City of Edmonton.

Energy Services

Energy Services is involved in the procurement, marketing and sale of electricity and natural gas in retail and wholesale markets in Alberta, Ontario and the Pacific North West.

Water Services

Water Services is primarily involved in the treatment and distribution of water within The City of Edmonton and other communities throughout Western Canada. This segment also provides complementary commercial services including the maintenance and repair of City of Edmonton-owned streetlighting and transportation support facilities.

Corporate

Corporate reflects the costs of the Company's net unallocated corporate office expenses and net financing income earned from intercompany guarantee fees and intercompany interest charges.

(Unaudited, in millions of dollars)

15. Segment disclosures (continued):

Three months ended September 30, 2007

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 239	$ 33	$ 593	$ 65	$ -	$ -	$ 930
Intersegment revenues	29	30	6	5	-	(70)	-
Total revenues	268	63	599	70	-	(70)	930
Energy purchases and fuel	121	20	514	-	-	(58)	597
Operations, maintenance, administration and foreign exchange (gain) loss	24	10	21	38	27	(12)	108
Franchise fee, property taxes and other taxes	4	11	-	2	-	-	17
Depreciation, amortization and asset retirement accretion	56	7	7	4	2	-	76
Operating expenses	205	48	542	44	29	(70)	798
Operating income (loss) before corporate charges	63	15	57	26	(29)		132
Corporate charges	18	4	6	3	(31)	-	-
Operating income	$ 45	$ 11	$ 51	$ 23	$ 2	$ -	$ 132
Capital additions	$ 70	$ 36	$ 1	$ 33	$ 6	$ -	$ 146

Three months ended September 30, 2006

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 163	$ 31	$ 452	$ 55	$ 1	$ -	$ 702
Intersegment revenues	29	35	6	1	-	(71)	-
Total revenues	192	66	458	56	1	(71)	702
Energy purchases and fuel	35	23	406	-	-	(62)	402
Operations, maintenance, administration and foreign exchange (gain) loss	45	15	17	31	16	(8)	116
Franchise fee, property taxes and other taxes	5	9	-	3	1	-	18
Depreciation, amortization and asset retirement accretion	36	7	7	5	3	-	58
Operating expenses	121	54	430	39	20	(70)	594
Operating income (loss) before corporate charges	71	12	28	17	(19)	(1)	108
Corporate charges	8	3	6	3	(20)	-	-
Operating income	$ 63	$ 9	$ 22	$ 14	$ 1	$ (1)	$ 108
Capital additions	$ 12	$ 14	$ 1	$ 29	$ 3	$ -	$ 59

(Unaudited, in millions of dollars)

15. Segment disclosures (continued):

Nine months ended September 30, 2007

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 694	$ 89	$ 1,744	$ 166	$ 1	$ -	$ 2,694
Intersegment revenues	83	92	15	8	-	(198)	-
Total revenues	777	181	1,759	174	1	(198)	2,694
Energy purchases and fuel	278	51	1,589	-	-	(168)	1,750
Operations, maintenance, administration and foreign exchange (gain) loss	82	39	59	99	64	(30)	313
Franchise fee, property taxes and other taxes	13	30	-	6	-	-	49
Depreciation, amortization and asset retirement accretion	139	20	21	14	8	-	202
Operating expenses	512	140	1,669	119	72	(198)	2,314
Operating income (loss) before corporate charges	265	41	90	55	(71)	-	380
Corporate charges	40	10	14	9	(73)	-	-
Operating income	$ 225	$ 31	$ 76	$ 46	$ 2	$ -	$ 380
Capital additions	$ 155	$ 72	$ 8	$ 82	$ 14	$ -	$ 331

Nine months ended September 30, 2006

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 496	$ 90	$ 1,462	$ 154	$ 1	$ -	$ 2,203
Intersegment revenues	84	102	16	1	-	(203)	-
Total revenues	580	192	1,478	155	1	(203)	2,203
Energy purchases and fuel	87	54	1,289	-	-	(180)	1,250
Operations, maintenance, administration and foreign exchange (gain) loss	101	45	55	91	42	(22)	312
Franchise fee, property taxes and other taxes	13	28	-	7	1	-	49
Depreciation, amortization and asset retirement accretion	110	19	21	13	9	-	172
Operating expenses	311	146	1,365	111	52	(202)	1,783
Operating income (loss) before corporate charges	269	46	113	44	(51)	(1)	420
Corporate charges	17	10	17	8	(52)	-	-
Operating income	$ 252	$ 36	$ 96	$ 36	$ 1	$ (1)	$ 420
Capital additions	$ 38	$ 37	$ 5	$ 57	$ 8	$ -	$ 145

(Unaudited, in millions of dollars)

15. Segment disclosures (continued):

Geographic information:

	Three months ended September 30, 2007				Three months ended September 30, 2006			
	Canada	US	Intersegment Eliminations	Total	Canada	US	Intersegment Eliminations	Total
Revenues - external	$ 818	$ 112	$ -	$ 930	$ 659	$ 43	$ -	$ 702
Intersegment revenues	9	6	(15)	-	7	1	(8)	-
Total revenues	$ 827	$ 118	$ (15)	$ 930	$ 666	$ 44	$ (8)	$ 702

	Nine months ended September 30, 2007				Nine months ended September 30, 2006			
	Canada	US	Intersegment Eliminations	Total	Canada	US	Intersegment Eliminations	Total
Revenues - external	$2,351	$ 343	$ -	$2,694	$2,058	$ 145	$ -	$2,203
Intersegment revenues	20	18	(38)	-	19	3	(22)	-
Total revenues	$2,371	$ 361	$ (38)	$2,694	$2,077	$ 148	$ (22)	$2,203

16. Comparative figures:

Certain of the comparative figures have been reclassified to conform with the current period’s presentation.