Consolidated Financial Statements of

EPCOR UTILITIES INC.

Years ended December 31, 2007 and 2006

Management's responsibility for financial reporting

The accompanying consolidated financial statements of EPCOR Utilities Inc. are the responsibility of management and have been approved by the Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with Canadian generally accepted accounting principles. The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to March 20, 2008. Financial information presented elsewhere in this annual report is consistent with that in the consolidated financial statements.

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

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

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

On behalf of management,

Don Lowry
President and Chief Executive Officer

Mark Wiltzen
Senior Vice President and
Chief Financial Officer

March 20, 2008

EPCOR UTILITIES INC.

Consolidated Financial Statements

Years ended December 31, 2007 and 2006

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AUDITORS' REPORT TO THE SHAREHOLDER OF EPCOR UTILITIES INC.

We have audited the consolidated balance sheets of EPCOR Utilities Inc. as at December 31, 2007 and 2006 and the consolidated statements of income, comprehensive income, changes in shareholder's equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of EPCOR Utilities Inc. as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Edmonton, Canada

March 20, 2008

KPMG LLP, is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International, a Swiss cooperative.

EPCOR UTILITIES INC.

Consolidated Statements of Income
(In millions of dollars)

Years ended December 31, 2007 and 2006

	2007	2006
Revenues	$ 3,663	$ 2,931
Operating expenses (income):		
Energy purchases	1,997	1,540
Fuel	309	146
Operations, maintenance and administration	517	470
Franchise fee, property taxes and other taxes	66	65
Depreciation, amortization and asset retirement accretion (note 5)	258	234
Foreign exchange gain	(37)	(4)
Gain on sale of power purchase arrangement and related transactions (note 4)	(34)	(378)
Net financing expenses (note 17)	171	155
	3,247	2,228
Income from continuing operations before income taxes and amounts in lieu of income taxes and non-controlling interests	416	703
Income taxes and amounts in lieu of income taxes (note 18)	112	10
Income from continuing operations before non-controlling interests	304	693
Non-controlling interests (note 14)	27	61
Net income from continuing operations	277	632
Net income from discontinued operations	-	10
Net income	$ 277	$ 642

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

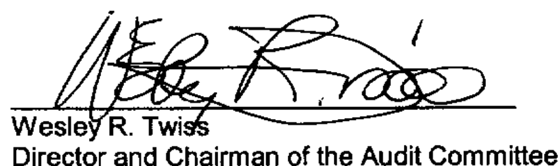
Consolidated Balance Sheets
(In millions of dollars)

December 31, 2007 and 2006

	2007	2006
Assets		
Current assets:		
Cash and cash equivalents (notes 21 and 25)	$ 79	$ 260
Accounts receivable	581	646
Income taxes recoverable	10	1
Inventories	62	57
Prepaid expenses	9	12
Derivative instruments assets (note 19)	104	26
Future income tax assets (note 18)	3	1
	848	1,003
Property, plant and equipment (note 5)	4,216	3,908
Power purchase arrangements (note 6)	679	757
Contract and customer rights and other intangible assets (note 7)	179	207
Derivative instruments assets (note 19)	116	20
Future income tax assets (note 18)	103	127
Goodwill (note 8)	185	183
Other assets (note 9)	236	178
	$ 6,562	$ 6,383

Approved on behalf of the Board:

Hugh J. Bolton
Director and Chairman of the Board



Wesley R. Twiss
Director and Chairman of the Audit Committee

	2007	2006

Liabilities and Shareholder's Equity

	2007	2006
Current liabilities:		
Short-term debt (note 10)	$ 138	$ 216
Accounts payable and accrued liabilities	615	608
Income taxes payable	44	19
Derivative instruments liabilities (note 19)	136	24
Other current liabilities	15	13
Future income tax liabilities (note 18)	39	92
Current portion of long-term debt (note 11)	388	63
	1,375	1,035
Long-term debt (note 11)	1,751	2,116
Derivative instruments liabilities (note 19)	78	27
Other non-current liabilities (note 12)	125	127
Future income tax liabilities (note 18)	126	84
	3,455	3,389
Non-controlling interests (note 14)	740	751
Shareholder's equity:		
Share capital (note 15)		
Retained earnings	2,430	2,245
Accumulated other comprehensive loss	(63)	(2)
	2,367	2,243
Contingencies and commitments (note 24)		
Subsequent events (notes 4 and 27)		
	$ 6,562	$ 6,383

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

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

Years ended December 31, 2007 and 2006

	2007	2006
Retained earnings:		
Balance, beginning of year	$ 2,245	$ 1,765
Adjustment for changes in accounting policies (note 2(b))	12	-
Net income	277	642
Common share dividends paid	(128)	(125)
Refundable taxes	24	(37)
Balance, end of year	2,430	2,245
Accumulated other comprehensive loss:		
Balance, beginning of year (note 2(b))	(2)	(8)
Adjustment for changes in accounting policies (note 2(b))	(41)	-
Other comprehensive income (loss)	(20)	6
Balance, end of year	(63)	(2)
Total shareholder's equity, end of year	$ 2,367	$ 2,243

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Statements of Comprehensive Income
(In millions of dollars)

Years ended December 31, 2007 and 2006

	2007	2006
Net income	$ 277	$ 642
Other comprehensive income (loss), net of income taxes:		
Unrealized losses on derivative instruments designated as cash flow hedges [1]	(70)	-
Reclassification of losses on derivative instruments designated as cash flow hedges to net income [2]	46	-
Unrealized gains on available-for-sale financial instruments [3]	4	-
Unrealized loss in self-sustaining foreign operations [4]	-	6
	(20)	6
Comprehensive income	$ 257	$ 648

(1) For the year ended December 31, 2007, net of income tax recovery of $29.

(2) For the year ended December 31, 2007, net of income tax expense of $20.

(3) For the year ended December 31, 2007, net of income tax expense of $1.

(4) For the years ended December 31, 2007 and December 31, 2006, net of income tax expense of nil.

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Statements of Cash Flows
(In millions of dollars)

Years ended December 31, 2007 and 2006

	2007	2006
Operating activities:		
Net income	$ 277	$ 642
Adjustments to reconcile net income to cash from operating activities:		
Depreciation, amortization and asset retirement accretion (note 5)	258	234
Gain on sale of power purchase arrangement and related transactions (note 4)	(34)	(378)
Reduction of Clover Bar asset retirement obligations	(5)	(13)
Non-controlling interests in Power LP (note 14)	19	43
Fair value changes on derivative instruments	(16)	-
Unrealized foreign exchange (gains) losses	(70)	19
Other items	12	6
Future income taxes and amounts in lieu of income taxes	76	(6)
	517	547
Change in non-cash operating working capital (note 16)	24	42
	541	589
Investing activities:		
Property, plant and equipment and other assets	(499)	(258)
Change in non-cash working capital	50	1
Non-bank sponsored asset backed commercial paper (note 9)	(71)	-
Business acquisitions, net of acquired cash (note 3)	-	(356)
Proceeds on sale of Battle River PSA interest (note 4)	59	336
Proceeds on sale of Sundance PSA interest (note 4)	-	17
Acquisition of interest in Battle River PSA (note 4)	-	(52)
Other	(8)	9
	(469)	(303)
Financing activities:		
Proceeds from issue of short-term debt	138	209
Repayment of short-term debt	(200)	(29)
Proceeds from issue of long-term debt	395	406
Repayment of long-term debt	(347)	(394)
Issue of subsidiary preferred shares (note 14)	121	-
Redemption of subsidiary preferred shares (note 14)	(200)	(150)
Distributions to non-controlling interests	(91)	(85)
Issue of limited partnership units of Power LP to non-controlling interests (note 14)	69	55
Common share dividends paid	(128)	(125)
Other	-	(4)
	(243)	(117)
Foreign exchange (loss) gain on cash held in a foreign currency	(10)	1
Net (decrease) increase in cash and cash equivalents	(181)	170
Cash and cash equivalents, beginning of year	260	90
Cash and cash equivalents, end of year	$ 79	$ 260
Supplementary cash flow information:		
Interest paid net of interest received	$ 161	$ 160
Income taxes paid net of income taxes recovered	29	3

See accompanying notes to consolidated financial statements.

1. Description of business:

(a) Nature of operations:

EPCOR Utilities Inc. (the Company or EPCOR) builds, owns and operates power plants, electrical transmission and distribution networks, water and wastewater treatment facilities and infrastructure, and provides energy and water services and products to its residential and commercial customers. The Company operates in Canada and the United States (U.S.), with its head office located in Edmonton, Alberta.

The common shares of EPCOR are owned by The City of Edmonton (the COE). The Company was established by City Council under City Bylaw 11071.

(b) Rate regulation:

EPCOR provides rate-regulated electric distribution and transmission services to customers within Edmonton and surrounding areas, and supplies electricity under Regulated Rate Tariffs (RRT) to customers in Alberta. EPCOR's electric distribution and transmission operations and its RRT operations are regulated by the Alberta Utilities Commission (AUC) (formerly the Alberta Energy and Utilities Board), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta) and the *Hydro and Electric Energy Act* (Alberta). The AUC administers these acts and regulations regarding tariffs, rates, construction, financing, operations, accounting and service area. The distribution and transmission businesses operate under cost-of-service regulation, whereby the AUC issues rate orders establishing the revenue requirements of these businesses, which are those revenues required to recover approved operating costs and to provide a rate of return on a deemed capital structure applied to approved rate base assets. The approved 2007 return on equity (ROE) for the distribution and transmission businesses was 8.51% (2006 – 8.93%). The RRT business has submitted a non-energy billing rate application to the AUC for its revenue requirement, commencing in 2007, requesting approval of rates to recover approved operating costs and a rate of return using the return margin approach, rather than the traditional return on rate base approach. Rates charged for energy sold to RRT customers are also approved by the AUC. On April 28, 2006, an Energy Price Setting Plan was approved for the period July 1, 2006 to June 30, 2011 which determines the energy margin, the procurement methodology and energy rates for the Company's RRT customers. The Company applies for tariff revenue based on estimated costs of service. Once the tariff is approved, it is not adjusted as a result of actual costs of service being different from those which were estimated other than for certain prescribed costs that are eligible for deferral account treatment. The allowed ROE is adjusted annually by formula for forecast changes in long-term Government of Canada bond yields.

1. Description of business, continued:

(b) Rate regulation, continued:

EPCOR's water treatment and distribution services to customers within the COE are rate regulated by the COE Council pursuant to a performance-based rates (PBR) bylaw. Rates approved pursuant to this bylaw are intended to allow the Company to recover its operating costs and earn a ROE of 11.25% (2006 – 11.50%), while also providing an incentive to manage costs below inflation. If performance targets outlined in the bylaw are achieved, water rates are increased by the change in the rate of inflation less an efficiency factor of 25 basis points.

The COE Council approved a renewal of the PBR bylaw on July 4, 2006 for the five-year period commencing April 1, 2007.

The regulator for water services provided within Edmonton, the COE, is a related party as it is the Company's shareholder.

Water sales to regional water commissions that supply water to communities surrounding Edmonton are rate regulated by the AUC on a complaints-only basis, whereby such communities may apply to the AUC to resolve disputes in connection with rates, tolls or charges determined by EPCOR. EPCOR sets the rates charged to the regional water commissions to recover related operating and capital costs plus a ROE.

2. Summary of significant accounting policies:

(a) Basis of presentation:

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP).

These consolidated financial statements include the accounts of EPCOR, its subsidiaries, and its proportionate share of assets, liabilities, revenues and expenses of joint ventures. They include the accounts of the Company's approximate 30.6% interest in EPCOR Power L.P. (Power LP). Under GAAP, EPCOR controls Power LP which therefore is a subsidiary of EPCOR.

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

2. Summary of significant accounting policies, continued:

(b) Changes in significant 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 financial statements have not been restated as a result of implementing the new accounting standards except to reclassify unrealized foreign currency translation gains and losses on net investments in self-sustaining foreign operations from the cumulative translation adjustment account to accumulated other comprehensive income, both within shareholder's equity.

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 available-for-sale financial instruments. 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 liabilities. Initially, all financial assets and financial liabilities must be recorded on the balance sheet at fair value with subsequent measurement determined by the classification of each financial asset and liability.

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

2. Summary of significant accounting policies, continued:

(b) Changes in significant accounting policies, continued:

Financial instruments, continued

Except for instruments that meet the definition of a derivative, the new standards provide the option to irrevocably designate a financial instrument as held for trading (the fair value option) on initial recognition or upon adoption of the standard. An instrument that is classified as held for trading by way of this fair value option must have a reliably determinable fair value and should eliminate or significantly reduce a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities. All other financial assets not meeting the Company's criteria for designating as held for trading are classified as available for sale, loans and receivables or held to maturity. The Company has designated any cash and cash equivalents and short-term financial investments as held for trading. Financial assets purchased or sold where the contract requires the asset to be delivered within an established timeframe are recognized on a settlement date basis.

Transaction costs on financial assets and liabilities classified as other than held for trading are capitalized and amortized over the expected life of the instrument utilizing the effective interest method. Previously, transaction costs related to long-term debt were deferred and amortized on a straight-line basis over the term of the debt. The effective interest method calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as derivative instruments assets and derivative instruments liabilities 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 of the effective portion of the derivatives are recorded in other comprehensive income. The Company chose a transition date of January 1, 2003 for embedded derivatives and therefore is only required to account separately for those embedded derivatives in any hybrid instruments issued, acquired or substantively modified after that date. The Company does not account for foreign currency derivatives embedded in non-financial instrument host contracts when the currency that is commonly used in contracts to purchase or sell non-financial items in the economic environment is that currency in which the transaction takes place.

Hedges

Hedge accounting 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.

2. Summary of significant accounting policies, continued:

(b) Changes in significant accounting policies, continued:

Hedges, continued

The Company uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in commodity prices. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while the ineffective portion is recognized in net income. The amounts recognized in accumulated other comprehensive income are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income or when the hedged item becomes probable of not occurring. For our detailed accounting policy on hedge accounting, refer to note 2(f) below.

Financial statement impact upon adoption

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 was recorded. Subsequent changes in the fair value of these contracts are reported in net income.

Qualifying cash flow hedges of electricity 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. Subsequent fair value changes in the effective portion of the associated derivative instruments are also 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 derivative instruments which did not satisfy all the requirements for hedge accounting, as previously disclosed, were recorded as derivative instruments assets on 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 hedges which were voluntarily discontinued by the Company in prior periods were included in derivative instruments liabilities on the balance sheet. These gains are recognized in net income in the same period or periods when the variability in the cash flows of the related hedged item affects net income. Consistent with the requirements of the new standards, these unrealized gains were reclassified to accumulated other comprehensive income as a cumulative opening adjustment.

2. Summary of significant accounting policies, continued:

(b) Changes in significant 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)
Physical power and natural gas purchase and sales contracts measured at fair value	Derivative instruments assets – current	$ 47
	Derivative instruments assets – non-current	94
	Derivative instruments liabilities – current	18
	Derivative instruments liabilities – non-current	27
	Future income tax liabilities – 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 assets –non-current	(12)
	Future income tax assets – non-current	4
	Opening retained earnings	(8)
Cash flow hedges measured at fair value	Derivative instruments assets – current	59
	Derivative instruments assets – non-current	32
	Future income tax assets – non-current	18
	Derivative instruments liabilities – current	71
	Derivative instruments liabilities – 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 liabilities –non-current	(6)
	Future income tax liabilities – 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)

2. Summary of significant accounting policies, continued:

(b) Changes in significant accounting policies, continued:

During the year ended December 31, 2007, these new standards impacted the financial statements as follows:

Financial statement line item	Increase (decrease)
Derivative instruments assets – current and non-current	$ (89)
Future income tax assets	9
Other assets	(7)
Derivative instruments liabilities – current and non-current	(27)
Future income tax liabilities	(1)
Non-controlling interests (balance sheet)	(22)
Revenues	2
Fuel expense	32
Net financing expenses	11
Income tax expense	(2)
Non-controlling interests (statement of income)	(22)
Other comprehensive income (loss)	(20)

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 Section 3030. The new section requires inventories to be measured at the lower of cost and net realizable value, which is consistent with the Company's current policy for measuring inventories held for resale. EPCOR currently measures inventories held for consumption at the lower of cost and replacement value. The Company's adoption of this standard on January 1, 2008 will not have a material impact on EPCOR's financial statements.

2. Summary of significant accounting policies, continued:

(b) Changes in significant accounting policies, continued:

Future accounting changes, continued

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

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

In 2005, the CICA announced plans to converge Canadian GAAP with IFRS over a transition period from 2006 to 2011. The CICA has indicated that Canadian reporting issuers will need to begin reporting under IFRS, including comparative figures, by the first quarter of 2011. The Company is currently assessing the impact of the differences in accounting standards to the Company's financial statements.

2. Summary of significant accounting policies, continued:

(c) Regulatory accounting:

The Company accounts for certain transactions in accordance with applicable rate regulation (regulatory accounting). Under regulatory accounting, the timing of the Company's recognition of certain assets, liabilities, revenues and expenses may differ from that otherwise expected under Canadian GAAP for non-rate-regulated enterprises.

Certain separate assets and liabilities have been recognized solely as a result of the effects of rate regulation. At December 31, 2007 and 2006, these assets and liabilities are not material.

For the Company's rate-regulated enterprises, the following accounting principles apply:

(i) *Asset disposals and retirements* - For rate-regulated transmission, distribution and RRT businesses, when an asset other than land or buildings is retired or disposed of, any proceeds are recorded as a reduction of the cost of the replacement asset, no gain or loss is reflected in income, and the related cost and accumulated depreciation are not removed until the end of the originally estimated useful life. Where there is no replacement asset, the proceeds are recorded as a reduction of the next most similar asset capitalized. On disposals of land and buildings, any difference between the proceeds and cost are recognized in income, the cost and accumulated depreciation are removed, and the accumulated depreciation on buildings is recorded in a deferral account to be returned to the rate payer in a future tariff application.

For rate-regulated water services businesses, any proceeds or salvage value is charged to accumulated depreciation, with no gain or loss reflected in income at the time of retirement or disposition. The results of the disposal or retirement are then recognized in future depreciation rates and depreciation charges. Cost and accumulated depreciation balances of retired assets are removed. In the case where an entire asset class ceases to exist, net proceeds in excess of accumulated depreciation are recorded as a gain on sale.

Non-rate-regulated entities include gains or losses on disposal of property, plant and equipment in current operating results at the time of retirement or disposition and the original cost and accumulated depreciation are removed.

2. Summary of significant accounting policies:

(c) Regulatory accounting, continued:

(ii) *Asset removal costs* - For rate-regulated transmission, distribution and RRT businesses, costs to remove an asset are included in the cost of the replacement asset. For rate-regulated water services businesses, future costs for decommissioning of assets are provided for based on estimated removal and site restoration costs, net of salvage value, as approved by the regulator. These amounts are recorded as a provision for plant decommissioning on the balance sheet with a corresponding increase in the cost of the related asset. Upon the retirement of water utility assets, the removal and site restoration costs, net of salvage value, are charged to the provision for plant decommissioning. The removal and site restoration costs for these assets are based on independent studies of plant decommissioning and site restoration commissioned by the Company and, where applicable, as directed by the regulator.

(iii) *Allowance for funds used during construction (AFUDC)* - The Company capitalizes AFUDC to provide for the cost of capital invested in rate-regulated construction activities. AFUDC is applied during construction at the weighted average cost of capital of the particular rate-regulated operations, as approved by the regulator. Since AFUDC includes not only an interest component, but also a cost-of-equity component, it exceeds the amount allowed to be capitalized under GAAP in similar circumstances in the absence of rate regulation.

(iv) *Intercompany profit on sales to rate-regulated affiliates* – The Company does not eliminate intercompany profits arising from sales within the consolidated group of EPCOR companies and included in assets remaining within its rate-regulated businesses, as the intercompany profit is deemed to have been realized to the extent that the sales price is recognized for rate-making purposes by the regulator. Intercompany profits included in assets remaining with a non-rate-regulated entity within the consolidated group are unrealized and are eliminated upon consolidation.

(d) Measurement uncertainty:

The preparation of the Company's financial statements, in accordance with Canadian GAAP, requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date.

By regulation, wire service providers in Alberta are not required to submit final load settlement data on customer electricity usage until eight months after the month in which such electricity was consumed. The data and associated processes and systems used by the Company to estimate electricity revenues and costs, including unbilled consumption, are complex. The Company's estimation procedures will not necessarily detect errors in underlying data provided by industry participants including wire service providers and load settlement agents.

2. Summary of significant accounting policies, continued:

(d) Measurement uncertainty, continued:

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

For determining asset impairments, purchase price allocations for business combinations, recording financial assets and liabilities, recording certain non-financial derivatives and for certain disclosures, the Company is required to estimate the fair value of certain assets or obligations. Estimates of fair value may be based on readily determinable market values or on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate. Financial instruments that do not satisfy the conditions required for hedge accounting are recorded at fair value, which may require the use of estimated future prices.

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

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

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

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

Certain estimates are necessary since the regulatory environment that the Company operates in often requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions, or other regulatory proceedings.

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

2. Summary of significant accounting policies, continued:

(e) Revenue recognition:

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

Revenues from the sale of goods are recognized when the products have been delivered. Revenues from services are recognized when the service has been performed or delivered.

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

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

Finance income earned from arrangements accounted for as direct financing leases is accounted for as described in note 2(r).

(f) Derivative instruments and hedging activities:

To reduce its exposure to movements in energy commodity prices, interest rate changes, and foreign currency exchange rates, the Company uses various risk management techniques including derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, and option contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. All derivative instruments, including embedded derivatives, are recorded at fair value on the balance sheet as described in note 2(b).

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

2. Summary of significant accounting policies, continued:

(f) Derivative instruments and hedging activities, continued:

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

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

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

The Company has used foreign currency denominated long-term debt to hedge exposure to changes in the carrying values of the Company's net investments in foreign operations which arise from changes in foreign exchange rates. On August 1, 2006, there was a reduction in the hedged net investment as a result of the sale of the Company's net investment in foreign operations. The amounts previously recognized in accumulated other comprehensive income were recognized in net income, as discussed in note 3.

The Company may use hedge accounting when there is a high degree of correlation between the risk in the derivative instrument designated as a hedge (the hedging instrument) and the item designated as being hedged (the hedged item). The Company documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retroactive and prospective basis. Fair value changes relating to derivative instruments designated as cash flow hedges are recognized as described in note 2(b) above. The Company has not designated any fair value hedges at the balance sheet date.

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

2. Summary of significant accounting policies, continued:

(f) Derivative instruments and hedging activities, continued:

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

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized as described in note 2(b). The fair value of derivative financial instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter price quotations by reference to bid or asking price as appropriate, in active markets. In illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. The Company has applied price modeling to the non-bank sponsored third-party asset backed commercial paper classified as held for trading as described in note 9. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

Certain commodity purchase and sale contracts are non-financial derivatives, but are exempted from derivative treatment since they are used for the expected purchase, sale, or usage requirements. In addition, certain other contracts are also not within the scope of derivative accounting standards as they are considered to be executory contracts or meet other exemption criteria.

2. Summary of significant accounting policies, continued:

(g) Income taxes:

Under the Income Tax Act (Canada) (ITA), a municipally owned corporation is subject to income tax on its taxable income if the income from activities for any relevant period that was earned outside the geographical boundaries of the municipality exceeds 10% of the corporation's total income for that period. As a result of these and other provisions, certain Canadian subsidiaries of the Company are taxable under the ITA and provincial income tax acts. The Company's U.S. subsidiaries are subject to income tax pursuant to U.S. federal and state tax laws.

From January 1, 2001, until the following reorganizations, the Company was required to pay amounts in lieu of income taxes (PILOT) to the Alberta Balancing Pool on certain of its Alberta operations. Following the reorganization of the Generation Services segment on January 3, 2006 and Energy Services segment on January 1, 2007, as described in note 18, the Company no longer has any entities subject to PILOT as they have become subject to the ITA and the Alberta Corporate Tax Act.

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

(h) Cash and cash equivalents:

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

(i) Inventories:

Inventories held for consumption are valued at the lower of cost and replacement cost. Inventories held for resale are valued at the lower of cost and net realizable value.

2. Summary of significant accounting policies, continued:

(j) Property, plant and equipment:

Property, plant and equipment are recorded at cost and include contracted services, materials, interest, direct and indirect labour, overhead costs, asset retirement costs, and net revenues during the pre-operating period. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers and non-repayable government grants. Contributions received for financing the costs of assets are recorded as a reduction of the related asset cost.

Depreciation on property, plant and equipment is provided on the straight-line basis over their estimated useful lives. The regulator approves depreciation rates for rate-regulated assets. No depreciation is provided on construction work in progress.

The Company capitalizes interest during construction for non-rate-regulated operations to provide for the costs of borrowing on construction activities. Interest is applied during construction using the average cost of debt associated with the specific project. The Company's rate-regulated operations capitalize AFUDC.

(k) Power purchase arrangements:

Acquired power purchase arrangements represent the cost to acquire the rights to the generating capacity of certain Alberta generation units (Alberta PPAs) and the price allocated to long-term sales contracts acquired as part of the Power LP and Primary Energy Ventures LLC acquisitions described in note 3 (Power LP PPAs). Acquired PPAs are reflected on the consolidated balance sheets as Power Purchase Arrangements and are recorded at cost and are amortized over their terms on a straight-line basis.

Alberta PPAs, which are comprised of the Sundance PPA and a portion of the Battle River PPA, reflect the cost to acquire the rights to the committed generating capacity of five regulated Alberta generation units auctioned by the Government of Alberta as part of provincial electricity deregulation. The cost of the Alberta PPAs also reflects the sale over a four-year period commencing in 2006 of the Company's interest in the Battle River PPA and related transactions, as described in note 4. Under the terms of the Alberta PPAs, the Company is obligated to make fixed and variable payments to the owners of the underlying generation units over their respective terms. Such amounts are recorded as operating expenses as incurred. At December 31, 2007, the remaining term of the 20-year Sundance PPA is 13 years. The Company is also obligated to make fixed and variable payments to the buyer of the Battle River PPA over the remaining two-year period until sale of the Company's remaining interest in the Battle River PPA is completed, as described in note 4.

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

2. Summary of significant accounting policies, continued:

(k) Power purchase arrangements, continued:

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

The Power LP PPAs reflect the cost to acquire long-term sales contracts under which revenue is earned by Power LP's generation units. The Power LP PPAs are amortized over their remaining terms, which range from one to 20 years.

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

Contract rights consist of acquired management and operations agreements and a long-term sales contract for the electricity generated by a plant acquired in 2000. Costs assigned to contract rights are amortized on a straight-line basis over the expected remaining contract terms from the dates of acquisition, which range from one to 70 years.

Customer rights represent the costs to acquire the rights to provide electricity services to particular customer groups. The costs are amortized on a straight-line basis over terms ranging from five to 30 years depending on the expectation of benefit from the underlying customer group.

Water rights associated with acquired hydroelectric power generation plants are recorded at cost and are amortized over the remaining useful lives of the associated property, plant and equipment.

Lease rights represent the cost to acquire land lease agreements for use in wind power projects in Ontario. The lease rights are amortized on a straight-line basis over the estimated useful lives of the related wind power assets, commencing when those assets are constructed and commissioned for service.

(m) Goodwill:

Goodwill is the cost of an acquisition less the fair value of the net assets of an acquired business. Goodwill is not amortized, but rather is tested for impairment at least annually or more frequently if events and circumstances indicate that a possible impairment may exist. To test for impairment, the fair value of the reporting unit to which the goodwill relates is compared to the carrying value, including goodwill, of the reporting unit. If the carrying value of the reporting unit exceeds its fair value, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the impairment loss, if any. The Company determines the fair value of a reporting unit using discounted cash flow techniques and estimated future cash flows.

2. Summary of significant accounting policies, continued:

(n) Other assets:

Non-bank sponsored third-party asset backed commercial paper is recorded at fair value and is classified as a non-current asset due to uncertainties associated with the timing of repayment.

Investments in which the Company exercises significant influence are accounted for using the equity method. Other investments are classified as available for sale and are recorded at fair value unless the investments do not have a quoted market price in an active market in which case the investments are recorded at cost. Investments recorded at cost for which there is a decline in fair value below cost that is other than temporary is written down and the loss is recognized in net income. Dividends received from equity investees which do not exceed cumulative equity in earnings subsequent to the date of investment are considered a return on investment and are classified as operating activities within the accompanying consolidated statements of cash flows. Cumulative dividends received in excess of cumulative equity in earnings subsequent to the date of investment are considered a return of investment and are classified as investing activities within the accompanying consolidated statements of cash flows.

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

(o) Impairment of long-lived assets:

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

(p) Deferred availability incentives:

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

2. Summary of significant accounting policies, continued:

(p) Deferred availability incentives, continued:

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

(q) Asset retirement obligations:

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

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

The Company is legally required to remove its rate-regulated distribution, transmission and water long-lived assets at the end of their useful lives and restore to original condition their associated sites. However, as the lives of these assets are indeterminate, the Company has not recorded asset retirement obligations since the estimated fair value of the obligations are not reasonably determinable. While the asset retirement obligations cannot be reasonably determined, the Company records a provision for decommissioning on its rate-regulated water assets as approved by its regulator.

(r) Leases or arrangements containing a lease:

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

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

2. Summary of significant accounting policies, continued:

(s) Contract liabilities:

In connection with the business acquisitions described in note 3, the Company assumed fair value liabilities primarily related to PPAs acquired. The portion of the purchase price allocated to contract liabilities is being amortized over the remaining terms of the contracts which expire in 2009.

(t) Foreign currency translation:

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

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

(u) Employee future benefits:

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

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

The Company maintains additional defined contribution and defined benefit pension plans to provide pension benefits to those employees (comprising less than 25% of total employees) who are not otherwise served by LAPP, including employees of new or acquired operations.

2. Summary of significant accounting policies, continued:

(u) Employee future benefits, continued:

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

(v) Offsetting of financial assets and financial liabilities:

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

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

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

3. Business acquisitions and disposals:

Acquisition of Primary Energy Ventures LLC:

On November 1, 2006, the Company, through its Power LP subsidiary, acquired 100% of the outstanding shares representing membership interests in Primary Energy Ventures LLC (Ventures). Ventures owns eight combined heat and power facilities located in the U.S. and 17.0% of the common interests and 14.2% of the preferred interests in Primary Energy Recycling Holdings LLC (PERH). PERH owns four waste heat recovery power facilities and a 50% interest in a coal pulverization facility in the U.S. In addition, Ventures provides management and administrative services to PERH and Primary Energy Recycling Corporation (PERC). PERC owns the balance of PERH not owned by Ventures.

3. Business acquisitions and disposals, continued:

Acquisition of Primary Energy Ventures LLC, continued:

The total consideration paid was $366 million (US$326 million) in cash plus acquisition costs of approximately $5 million for a total purchase price of $371 million. The purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values. The purchase price was allocated as follows:

Current assets excluding cash and cash equivalents	$ 26
Property, plant and equipment	140
Power purchase arrangements (included in Power LP PPAs)	138
Contract rights and other intangible assets	14
Future income tax assets, non-current	8
Goodwill	34
Other assets, including long-term investments of $59	99
Current liabilities	(15)
Capital lease obligations	(79)
Other non-current liabilities	(11)
	354
Cash and cash equivalents	17
Fair value of net assets acquired	$ 371

The results of operations of Ventures are included in the Company's consolidated statements of income and retained earnings from the date of acquisition. Such results of operations and the related assets and liabilities at the balance sheet date, including goodwill, are included in the Generation segment. The goodwill is deductible for income tax purposes.

Sale of Frederickson power plant and related entities:

On August 1, 2006, the Company finalized the sale of certain of its subsidiaries associated with its interest in its Frederickson power plant to Power LP. No gain or loss was recognized on the inter-company sale. As a result of the sale, the Company recognized a reduction in the net investment in the Frederickson operations to the extent of the non-controlling interest in Power LP of approximately 69.4%. The recognition into net income of the previously deferred foreign exchange losses included in accumulated other comprehensive income was partially offset by recognition of the foreign exchange gain on repayment of the U.S. dollar debt designated as a hedge of the net investment in the foreign operations. The resulting net foreign exchange loss of $6 million is included in foreign exchange gains and losses in the consolidated statements of income.

4. Sale of power purchase arrangement and related transactions:

EPCOR acquired the Battle River Power Purchase Arrangement (Battle River PPA) in August 2000 through an auction conducted by the Government of Alberta as part of provincial electricity deregulation. The Battle River PPA includes Alberta Power (2000) Ltd.'s Battle River generation units 3, 4 and 5 with a total committed capacity of 662.8 megawatts. Following acquisition of the Battle River PPA, the rights under the PPA were assigned under the Battle River Power Syndicate Agreement (Battle River PSA) to the syndicate members, including an EPCOR subsidiary. As a result, the syndicate members held the beneficial ownership of the committed capacity and ancillary services produced by the Battle River generation units.

On June 5, 2006, the Company finalized an agreement to sell its Battle River PPA and its related interest in the Battle River PSA to ENMAX Corporation (ENMAX). The Battle River PSA interest will be sold over a four-year period. The agreement called for the initial sale of a 55% interest in the Battle River PSA for gross cash proceeds of $343 million on June 5, 2006. The remaining 45% interest will be sold for gross proceeds of $224 million, subject to closing adjustments, and recognized when the interest and associated risks and rewards of beneficial ownership are legally transferred to ENMAX from 2007 through 2010.

On January 1, 2007, 10% of the 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

Refundable taxes of $7 million, which arose from the taxable capital gains on the sale of the Battle River PSA, have been charged to retained earnings.

The timing of the remaining future sales include the sale of 10% interests closing on each of January 1, 2008 and 2009, followed by the sale of the final 15% interest on January 1, 2010.

The sale of the initial 55% interest in the Battle River PSA was completed through a series of transactions. Just prior to the sale, the Company owned approximately 70% of the total interest in the Battle River PPA via the PSA, with the remaining 30% interest owned by various third parties (non-EPCOR syndicate members). To facilitate the eventual sale to ENMAX of a 100% interest in the Battle River PSA, the Company acquired the remaining 30% interest in the PSA from the non-EPCOR syndicate members for cash consideration and a non-monetary exchange of an equivalent value ownership interest in the Company's Sundance Power Syndicate Agreement (the Sundance Swap). The acquired 30% interest in the Battle River PSA was measured at the exchange amount of the Sundance Swap of $134 million and cash consideration of $52 million, for a resulting carrying amount of the 30% interest in the Battle River PSA of $186 million prior to its sale to ENMAX.

4. Sale of power purchase arrangement and related transactions, continued:

Following the Company’s acquisition of the 30% Battle River PSA interest from the non-EPCOR syndicate members, the Company completed the sale of the initial 55% interest in the Battle River PSA for cash consideration of $343 million. A pre-tax gain of $329 million, after disposal costs, final purchase price adjustments and excluding proceeds relating to operating income from May 1 to June 5, was recognized on the initial interest sold.

In addition to the Sundance Swap, the Company sold an additional interest in the Sundance Power Syndicate Agreement (the Sundance Extension) to non-EPCOR syndicate members for cash consideration of $17 million and notes receivable of $40 million. The notes receivable bear interest at 5.35% per annum and are to be repaid in monthly payments of principal and interest through to December 31, 2020. At December 31, 2007, the non-current portion of the notes receivable of $35 million (2006 – $37 million) is recorded in other assets and the current portion of $2 million (2006 - $2 million) is recorded in accounts receivable. The pre-tax gain recognized on sale of the Sundance Extension, after final purchase price adjustments, was $49 million. In total, the Company sold 25.5% of its previously-held 70% interest in the Sundance PSA through the non-monetary exchange for the Battle River PSA interest and the Sundance Extension sale.

4. Sale of power purchase arrangement and related transactions, continued:

The proceeds and resulting gain arising from the sale and related transactions for the year-ended December 31, 2006 are comprised of:

	Sale of 55% interest in Battle River PSA	Purchase of interest in Battle River PSA	Sale of Sundance Extension	Total
Cash proceeds from sale	$ 343	$ -	$ 17	$ 360
Cash paid to acquire Battle River PSA interest from non-EPCOR syndicate member	-	(52)	-	(52)
Cash proceeds for purchase price adjustments	1	-	-	1
Cash proceeds on Battle River PSA relating to operating income between May 1 effective date and June 5 closing date	(6)	-	-	(6)
Disposal costs	(2)	-	-	(2)
Net cash proceeds received (consideration paid)	336	(52)	17	301
Notes receivable from non-EPCOR syndicate members on Sundance Extension sale	-	-	40	40
Total proceeds (payments)	336	(52)	57	341
Increase in carrying value of Battle River PSA arising from Sundance Swap and purchased interest, respectively	134	52	-	186
Carrying value of disposed 55% interest in Battle River PSA	(121)	-	-	(121)
Carrying value of disposed interest in Sundance PSA	(20)	-	(8)	(28)
Gain on sale before income taxes	$ 329	$ -	$ 49	378
Future income taxes				51
Gain on sale after income taxes				$ 327

Refundable taxes of $42 million, which arose from taxable capital gains on the sale of the Battle River PPA and interest in the PSA, have been charged to retained earnings. The income taxes and refundable taxes of $51 million and $42 million, respectively, are recorded as an increase of $24 million in future income tax liabilities (2006 - $93 million) and an increase of $69 million in current income taxes payable (2006 - nil) on the consolidated balance sheets. Refundable taxes of $36 million previously recorded as current future income tax liabilities in the prior year have been reversed out of retained earnings and recorded as a charge to current income taxes payable as a result of the payment of qualifying dividends.

5. Property, plant and equipment:

				2007
	Composite depreciation rates	Cost	Accumulated depreciation	Net book value
Generation plants and equipment	3.4%	$ 3,268	$ 779	$ 2,489
Water treatment and distribution	2.0%	1,291	303	988
Electricity transmission and distribution	3.2%	962	345	617
Retail systems and equipment	11.4%	109	50	59
Corporate information systems and equipment	9.1%	135	77	58
		5,765	1,554	4,211
Contributions:				
Generation plants and equipment	13.3%	(9)	(2)	(7)
Water treatment and distribution	1.4%	(438)	(80)	(358)
Electricity transmission and distribution	2.8%	(104)	(38)	(66)
		(551)	(120)	(431)
Assets under capital lease	2.0%	2	1	1
Land	None	94	-	94
Construction work in progress	None	341	-	341
		$ 5,651	$ 1,435	$ 4,216

5. Property, plant and equipment, continued:

				2006
	Composite depreciation rates	Cost	Accumulated depreciation	Net book value
Generation plants and equipment	3.6%	$ 3,365	$ 847	$ 2,518
Water treatment and distribution	2.0%	1,137	288	849
Electricity transmission and distribution	3.1%	908	328	580
Retail systems and equipment	10.5%	100	46	54
Corporate information systems and equipment	11.9%	108	66	42
		5,618	1,575	4,043
Contributions:				
Generation plants and equipment	16.2%	(8)	(1)	(7)
Water treatment and distribution	1.4%	(428)	(74)	(354)
Electricity transmission and distribution	2.8%	(100)	(35)	(65)
		(536)	(110)	(426)
Assets under capital lease	7.5%	71	1	70
Land	None	94	-	94
Construction work in progress	None	127	-	127
		$ 5,374	$ 1,466	$ 3,908

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

	2007	2006
Continuing operations:		
Depreciation on assets in service	$ 189	$ 187
Accretion of asset retirement obligations	5	5
Gain on disposal of assets	(7)	(7)
Amortization of contributions	(10)	(10)
Amortization of PPAs	57	50
Amortization of contract and customer rights and other intangible assets	11	9
Write down of management agreement (note 7)	13	-
	$ 258	$ 234

5. Property, plant and equipment, continued:

Interest and AFUDC capitalized to property, plant and equipment for 2007 is $14 million (2006 - $5 million).

6. Power purchase arrangements:

			2007			2006
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Alberta PPAs	$ 219	$ 78	$ 141	$ 240	$ 66	$ 174
Power LP PPAs	633	95	538	633	50	583
	$ 852	$ 173	$ 679	$ 873	$ 116	$ 757

7. Contract and customer rights and other intangible assets:

			2007			2006
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Contract rights	$ 120	$ 9	$ 111	$ 137	$ 6	$ 131
Customer rights	106	61	45	106	56	50
Water rights	15	1	14	15	-	15
Lease rights	6	-	6	6	-	6
Emission credits	5	2	3	5	-	5
	$ 252	$ 73	$ 179	$ 269	$ 62	$ 207

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 of nil and recorded a $13 million pre-tax impairment charge to depreciation, amortization and asset retirement accretion in the year. The asset was previously recorded in the Generation segment.

8. Goodwill

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

	2007	2006
Balance, beginning of year	$ 183	$ 149
Goodwill acquired on Ventures acquisition (note 3)	-	33
Adjustments to purchase price allocations	2	-
Goodwill acquired on other business acquisitions	-	1
	$ 185	$ 183

9. Other assets:

	2007	2006
Carrying value		
Non-bank sponsored asset backed commercial paper	$ 60	$ -
Investment in PERH	50	57
Loans and other long-term receivables	70	56
Net investment in lease	29	35
Debenture issue expenses	-	22
Portfolio investments	13	9
Other	16	7
	238	186
Accumulated amortization		
Debenture issue expenses	-	7
Other	2	1
	2	8
	$ 236	$ 178

9. Other assets, continued:

Non-bank sponsored asset backed commercial paper

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

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

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

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

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

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

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

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

9. Other assets, continued:

Non-bank sponsored asset backed commercial paper, continued

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

Under the proposed restructuring, EPCOR expects that $61 million of its original ABCP investment cost (in two conduits) will be exchanged for FRNs associated with the pooled synthetic asset conduit. These FRNs will be comprised of senior and subordinated notes, the relative breakdown of which will be determined by an assessment by JP Morgan Chase & Co., the financial adviser to the Investors Committee. The senior notes are expected to receive the second highest investment-grade credit rating from an independent recognized credit rating agency. The subordinated notes may not be assigned a credit rating, however EPCOR expects that the subordinated notes could be investment grade.

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

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

ABCP is a financial instrument and has been classified as held for trading and therefore is recorded at fair value. EPCOR has recognized a decrease in fair value of $11 million during the year, representing the difference between the original investment cost of $71 million and the estimated fair value of $60 million at December 31, 2007. There are no observable market prices for ABCP as at the balance sheet date. Accordingly, EPCOR has estimated the fair value using a probability-weighted discounted cash flow approach based on the assumed credit ratings and potential ratings actions on the applicable ABCP conduits under the proposed restructuring, observable interest rates and credit spreads for estimating future interest payments and applicable discount rates, the cost of margin call facilities (1.60% of the FRN investments), the cost of the proposed restructuring (.001% of the FRN investments), estimated recovery periods based on the estimated lives of the underlying assets of the proposed restructuring conduits (7 years for pooled asset FRNs and 9 years for ineligible asset FRNs) and ranges of recoverability based on publicly available default statistics for credit-rated entities.

9. Other assets, continued:

Non-bank sponsored asset backed commercial paper, continued

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

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

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

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

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

9. Other assets, continued:

Investment in PERH

In connection with the Ventures acquisition described in note 3, the Company acquired 17.0% of the common share interests and 14.2% of the preferred share interests in PERH. The Class B Common interest has been accounted for using the equity method. The Class B Preferred interest has been recorded on the cost basis. For the year ended December 31, 2007, equity losses of $4 million (for the two-month period ended December 31, 2006 - $1 million) included in operations, maintenance and administration expense, and $3 million (for the two-month period ended December 31, 2006 - $1 million) in dividends have been recorded against the common share investment in PERH. Upon acquisition, the excess of the Company's share of the book value of PERH net assets over the carrying value of the Class B Common interest was $19 million.

Net investment in lease

Through the Ventures acquisition, the Company acquired a power generation facility located in Oxnard, California. The PPA under which this facility operates is considered to be a direct financing lease for accounting. The PPA expires in 2020. The current portion of the net investment in lease of $1 million (2006 - $1 million) is included in accounts receivable. Financing income for the year ended December 31, 2007 of $3 million (for the two-month period ended December 31, 2006 - $1 million) is included in revenues.

10. Short-term debt:

	2007	2006
Power LP bridge acquisition credit facility	$ -	$ 216
Commercial paper	138	-

Bank lines of credit are unsecured and are available to the Company up to an amount of $1,565 million, comprised of committed amounts of $1,500 million as described in note 11 and uncommitted amounts of $65 million. Letters of credit totaling $357 million have been issued under these facilities as described in note 25. Amounts borrowed, and letters of credit issued, if any, under these facilities which are not payable within one year, are classified as long-term debt.

The Company's commercial paper program is authorized to $500 million and is backed by the committed bank lines.

11. Long-term debt:

	Effective Interest Rate	2007	2006
Obligation to the City of Edmonton, net of sinking fund (note 20):			
Due in 1-5 years at 10.50%[1] (2006 – 10.70%[1])	11.70%	$ 110	$ 127
Due in 6-10 years at 8.86%[1] (2006 - 9.21%[1])	10.42%	40	84
Due in 11-15 years at 8.37%[1] (2006 - 8.75%[1])	9.34%	91	71
Due in 16-20 years at 5.75%[1] (2006 - 7.01%[1])	5.75%	2	27
		243	309
Debentures, at 6.20%, due in 2008	6.40%	200	200
Debentures, at 6.95%, due in 2010	7.12%	200	200
Debentures, at 6.60%, due in 2011	6.88%	200	200
Debentures, at 6.75%, due in 2016	6.94%	130	130
Debentures, at 6.80%, due in 2029	7.05%	150	150
Debentures, at 5.65%, due in 2035	5.88%	200	200
Power LP unsecured senior notes (US$190), at 5.90%, due in 2014	6.16%	191	225
Power LP unsecured senior notes, at 5.95%, due in 2036	6.12%	210	210
Power LP unsecured senior notes (US$150), at 5.87%, due in 2017	6.01%	149	-
Power LP unsecured senior notes (US$75), at 5.97%, due in 2019	6.11%	74	-
Power LP secured term loan, at 11.25%, due in 2010	11.57%	4	5
Non-recourse financing:			
Brown Lake Project, at 8.7%, due in 2016	8.69%	7	8
Joffre Cogeneration Project, at fixed and floating rates, due in 2020	8.82%	41	60
Revolving extendible credit facilities, at floating rates, due in 2008	4.86%	155	-
Power LP revolving extendible credit facilities, at floating rates, due in 2009		-	149
Power LP bridge acquisition credit facility (US$44), at floating rates, due in 2009		-	51
Obligations under capital leases		1	82
		2,155	2,179
Less: Current portion		388	63
Deferred debt issue costs		16	-
		$ 1,751	$ 2,116

[1] Weighted average coupon rate on gross principal balance outstanding

11. Long-term debt, continued:

Obligation to the City of Edmonton

Debentures were issued, on behalf of the Company, pursuant to the City of Edmonton (COE) Bylaw authorization. The outstanding debentures are a direct, unconditional obligation of the COE. The Company's obligation to the COE matches the COE's obligation pursuant to the debentures. The portion of the 8.37% debentures, maturing in the year 2018 and totaling $66 million, rank as subordinated debt. In the event of default on other interest obligations, the coupon and sinking fund payments on the subordinated debt may be deferred for a period of up to five years, not exceeding the maturity date. If still in default at the end of five years, all unpaid payments plus accrued interest thereon may be repaid by issuing common shares to the COE. Except for the subordinated debt, the obligation to the COE will rank at least equal to all future debt that may be issued by the Company.

The Company makes annual contributions into the Sinking Fund of the COE pertaining to certain debenture issues. These payments constitute effective settlement of the respective debt as the sinking fund accumulates to satisfy the underlying debenture maturity. For any specific COE debenture with sinking fund requirements, the payment obligation ceases on maturity of the debenture.

Debentures

The Debentures are unsecured direct obligations of the Company and, subject to statutory preferred exemptions, rank equally with all other unsecured and unsubordinated indebtedness of the Company. The debentures are redeemable by the Company prior to maturity at the greater of par and a price specified under the terms of the debenture.

Power LP unsecured senior notes

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

The unsecured senior medium term notes of $210 million issued during 2006 are due in June 2036 with interest payable semi-annually.

The unsecured senior medium term notes of $223 million (US$225 million), less issue costs of $1 million (US$1 million), were issued in two tranches. The $149 million (US$150 million) and $74 million (US$75 million) issued during 2007 are due in August of 2017 and 2019 respectively with interest payable semi-annually.

11. Long-term debt, continued:

Power LP secured term loan

The term loan is secured by a first fixed and specific mortgage over the Queen Charlotte plant which has a carrying value of $15 million (2006 - $15 million). The loan bears interest at an annual rate of approximately 11.3% and matures on July 15, 2010.

Non-recourse financing

Joffre Cogeneration Project financing represents the Company's share, through its subsidiary, EPCOR Power Development Corporation, of syndicated loans for the project. A $40 million portion of the debt bears a fixed interest rate of 8.59% payable quarterly until September 2020. The remaining debt bears interest at the prevailing bankers' acceptance rate plus a spread of 1.50% (2006 - 1.50%) which escalates to 1.875% over the term of the loan. The debt is secured by a charge against project assets which have a carrying value of $110 million (2006 - $114 million). Brown Lake Project financing is secured by a charge against project assets which have a carrying value of $12 million (2006 - $12 million).

Three-year and five-year extendible syndicated bank credit facility

An $800 million extendible syndicated bank revolving credit facility, consisting of three-year and five-year tranches of $400 million each, is available to the Company. At December 31, 2007, the Company had $155 million outstanding under this facility, which are repayable in 2008 (2006 – nil).

Two-year extendible credit facilities

Unsecured two-year credit facilities of $100 million each for a total of $400 million, committed to 2009, are available to the Company. At December 31, 2007, the Company had nil outstanding under the two-year extendible credit facilities (2006 – nil).

Power LP revolving extendible credit facilities

Unsecured three-year credit facilities of $100 million each for a total of $300 million, committed to September 2009, October 2009 and June 2010 respectively, are available to the Company. At December 31, 2007, the Company had not drawn against these facilities (2006 - $149 million). Under the terms of the facilities, the Company may obtain advances by way of prime loans, US base rate loans, LIBOR loans and bankers' acceptances.

11. Long-term debt, continued:

Capital lease obligations

On August 24, 2007, 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.

Principal repayments

Principal repayments to lenders and payments into The Sinking Fund of The City of Edmonton, over the next five years are as follows:

2008	$	388
2009		26
2010		221
2011		215
2012		52

12. Other non-current liabilities:

		2007		2006
Asset retirement obligations (note 13)	$	92	$	87
Employee future benefit liabilities		20		17
Other		13		23
	$	125	$	127

13. Asset retirement obligations:

	2007	2006
Balance, beginning of year	$ 99	$ 108
Liabilities incurred	8	10
Liabilities settled	(12)	(24)
Asset retirement accretion expense	5	5
	100	99
Less: current portion in accounts payable and accrued liabilities	8	12
	$ 92	$ 87

The Company estimates the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $372 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2008 and 2090. The majority of the payments to settle the obligations are expected to occur between 2027 and 2064 for the power generation plants, and between 2008 and 2012 for sections of the Genesee coal mine. Discount rates ranging from 4.1% to 6.7% were used to calculate the carrying value of the asset retirement obligations. No assets have been legally restricted for settlement of these liabilities.

14. Non-controlling interests:

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

	2007	2006
Non-controlling interests in Power LP	$ 19	$ 43
Preferred share dividends paid by subsidiary companies	12	17
Preferred share issue costs recognized on redemption of preferred shares	3	1
Recovery of preferred share dividend taxes recognized in prior periods	(7)	-
	$ 27	$ 61

14. Non-controlling interests, continued:

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

	2007	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	19	43
Other comprehensive loss attributable to non-controlling interests	(2)	-
Opening accumulated other comprehensive income adjustments attributable to non-controlling interests (note 2(b))	4	-
Opening retained earnings adjustments attributable to non-controlling interests (note 2(b))	66	-
Distributions to non-controlling interests	(92)	(86)
Non-controlling interests in Power LP, end of year	618	554
Preferred shares issued by subsidiary companies, beginning of year	197	346
Issue of preferred shares	122	-
Redemption of preferred shares	(197)	(149)
Preferred shares issued by subsidiary companies, end of year	122	197
	$ 740	$ 751

The non-controlling interests in Power LP represents the approximately 69.4% interest in Power LP not owned by EPCOR.

Preferred shares issued by subsidiary companies

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

The carrying value of the Series I 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.

14. Non-controlling interests, continued:

Preferred shares issued by subsidiary companies, continued

During 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 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 Ventures in November 2006. Future income tax assets of $1 million related to 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. The Company will not make any distributions on the Power LP units if the declaration or payment of dividends on the preferred shares is in arrears. Dividends will not be paid on the preferred shares if the Power LP unsecured senior notes are in default.

On June 30, 2006, EPCOR Finance Corporation, a subsidiary of the Company, redeemed 6 million Cumulative Redeemable Perpetual First Preferred Shares, Series A (Series A Preferred Shares) at par for $150 million cash.

The carrying value of the Series A Preferred Shares prior to their redemption by the Company was $149 million, reflecting $150 million less issue costs of $1 million which were incurred when the preferred shares were issued in 2001. The $1 million difference between the redemption price and the carrying value has been charged to non-controlling interests in the consolidated statements of income.

15. Share capital:

Authorized:
Unlimited number of voting common shares without nominal or par value.

Issued:
Three common shares for nominal value to The COE.

16. Change in non-cash operating working capital:

	2007	2006
Accounts receivable	$ 71	$ (42)
Income taxes recoverable	(9)	11
Inventories	(7)	(7)
Prepaid expenses	3	-
Accounts payable and accrued liabilities	(44)	76
Income taxes and amounts in lieu of income taxes payable	9	9
Other current liabilities	1	(5)
	$ 24	$ 42

17. Net financing expenses:

	2007	2006
Interest on long-term debt	$ 167	$ 164
Interest on short-term debt and other financing costs	8	4
Fair value changes on financial instruments	12	(2)
Interest on capital lease obligations	4	1
Realized losses on interest rate contracts	2	-
Amortization of debt issue costs	2	2
Capitalized interest and AFUDC	(14)	(5)
Interest and dividend income	(10)	(9)
	$ 171	$ 155

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

	2007	2006
Current income taxes and amounts in lieu of income taxes	$ 84	$ 20
Future income taxes and amounts in lieu of income taxes	28	(10)
	$ 112	$ 10

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

	2007	2006
Net income from continuing operations before income taxes and amounts in lieu of income taxes and non-controlling interests	$ 416	$ 703
Statutory income tax rates	32.12%	32.50%
Income taxes and amounts in lieu of income taxes at statutory rates	134	229
Increase (decrease) resulting from:		
Change due to enactment of SIFT legislation	48	-
Income exempt from income taxes at statutory rates	(28)	(54)
Non-taxable (non-deductible) amounts	(28)	9
Adjustment for enacted changes in income tax laws and rates	13	32
Non-taxable portion of capital gains	(12)	(89)
Future income taxes due to change in tax status	(10)	-
Unrecognized future income tax assets	(2)	(2)
Net future income tax assets recognized on corporate restructuring within the Generation segment	-	(117)
Other	(3)	2
	$ 112	$ 10

18. Income taxes and amounts in lieu of income taxes, continued:

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

	2007	2006
Future income tax assets:		
Non-capital losses carried forward (expiring 2008 to 2027)	$ 76	$ 57
Cumulative eligible capital	65	94
Property, plant and equipment – differences in net book value and undepreciated capital cost	35	24
Investment in partnership	23	2
Asset retirement obligations	13	22
Contract and customer rights and other intangible assets	8	-
Capital losses carried forward	-	9
Other	12	7
	232	215
Future income tax liabilities:		
Investment in partnership	173	95
Deferred income from partnership	56	108
Property, plant and equipment – differences in net book value and undepreciated capital cost	26	24
Power purchase arrangements	13	18
Long-term debt	8	-
Asset retirement obligation assets	7	8
Derivative financial instruments	-	6
Other	8	4
	291	263
Net future tax (liabilities) assets	$ (59)	$ (48)
Presented on the balance sheet as follows:		
Current assets	$ 3	$ 1
Non-current assets	103	127
Current liabilities	(39)	(92)
Non-current liabilities	(126)	(84)
	$ (59)	$ (48)

At December 31, 2007, the Company has non-capital losses carried forward of approximately $254 million (2006 - $190 million), of which $49 million (2006 - $33 million) relate to certain U.S. subsidiaries. These losses expire between 2008 and 2027. The Company also has taxable capital losses of approximately $16 million (2006 - $20 million) and restricted limited partnership losses of approximately $8 million (2006 - nil) which carry forward indefinitely. There are income tax losses available to be carried forward of $16 million (2006 - $6 million) for which no tax benefit has been recognized.

18. Income taxes and amounts in lieu of income taxes, continued:

Refundable taxes of $13 million (2006 - $37 million) recorded in retained earnings include $7 million (2006 - $42 million) arising from the sale of the Battle River PPA and related transactions as described in note 4. The December 31, 2006 balance of refundable taxes includes a reduction of $5 million as a result of the Company's sale of its interest in the Frederickson power plant and related entities as described in note 3.

Tax on flow-through entities

Currently, the taxable income of Power LP is expected to be taxed in the hands of its unit holders. Canadian tax legislation related to specified investment flow-through entities (SIFT Legislation) included in Bill C-52 was enacted in 2007 and will result in changes to how certain publicly traded trusts and partnerships, including Power LP, are taxed. The SIFT Legislation applies a tax at the specified investment flow-through entity level on certain income and at tax rates comparable to the combined federal and provincial corporate tax rates, and then re-characterizes that income net of tax payable as taxable dividends in the hands of unit holders. The SIFT Legislation will apply to Power LP starting the earlier of January 1, 2011 or January 1 of the year following the date at which the Power LP exceeds the normal growth guidelines issued by the Department of Finance (Canada) on December 15, 2006. EPCOR does not expect the Power LP to be subject to the new rules prior to the January 1, 2011 date.

Enactment of the SIFT Legislation resulted in the recognition of future income taxes expense and net future tax liabilities of $48 million in 2007, based on estimated net taxable temporary differences which are expected to reverse after 2010 and for which no tax has previously been recorded at the partnership level. The Company previously recognized its 30.6% share of these future income taxes, commencing upon acquisition of Power LP, and the resulting additional future income taxes expense relates entirely to the non-controlling interests in Power LP.

Corporate income tax rate reductions

Effective December 14, 2007, the Government of Canada enacted Bill C-28 whereby the federal corporate income tax rate is scheduled to be reduced in increments over the period from January 1, 2008 to December 31, 2012, for a total reduction of 3.5%. These rate reductions were in addition to those included in the Government of Canada's Bill C-52 which was enacted on June 22, 2007. The effect of Bill C-52 was to reduce the general corporate tax rate from 19% to 18.5% commencing January 1, 2011. As a result, the amount of net future income tax assets balances was reduced by $1 million in the second quarter of 2007 and $12 million in the fourth quarter of 2007, with corresponding increases in future income tax expense.

18. Income taxes and amounts in lieu of income taxes, continued:

Corporate income tax rate reductions, continued

Effective April 1, 2006, the Government of Alberta enacted an amendment to the Alberta Corporate Tax Act that reduced corporate income taxes from 11.5% to 10% of taxable income. On June 6, 2006, the Government of Canada passed Bill C-13 whereby the federal corporate income tax rate is scheduled to be reduced in increments over the period from January 1, 2008 to December 31, 2010, for a total reduction of 3.12%. The Company has estimated the impact of these tax rate reductions, based on expected timing of the reversal of its taxable and deductible temporary differences, to be a $32 million charge to consolidated net income and a corresponding reduction in future income tax assets net of liabilities.

Corporate restructuring within the Energy Services segment

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 in the first quarter of 2007. The resulting future income tax assets will be reduced over time, as the underlying income tax deductions are utilized to reduce taxable income.

Corporate restructuring within the Generation segment

On January 3, 2006, the Company reorganized certain subsidiaries within its Generation segment to better align its legal structure with its operating structure and thereby realize efficiencies.

Since January 1, 2001 and until the completion of certain transactions under this restructuring, EPCOR Generation Inc. (EGI), a wholly-owned subsidiary of EPCOR, was subject to and made payments under PILOT. As a result of the restructuring, EGI no longer met the criteria for exemption from tax under section 149 of the ITA and therefore became taxable under the ITA effective January 3, 2006.

Under the ITA, when becoming taxable, EGI was deemed to have disposed of and reacquired all of its property at fair market value for income tax purposes. Since the fair market value of its property is greater than its underlying net book values, EGI will have additional deductions available for income tax purposes. The resulting net tax effect was recognized in the first quarter of 2006 as 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. The resulting future income tax assets will be reduced over time, as the underlying income tax deductions are utilized to reduce taxable income.

19. Financial instruments:

Fair value and classification of financial assets and liabilities

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 and other current liabilities are classified as other financial liabilities. Accounts receivable, accounts payable and accrued liabilities and other current 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 Company's beneficial interest in the Sinking Fund related to the COE debentures, preferred share interest held in PERH, and common share interests in capital venture investments are classified as available for sale.

The classification, carrying values and fair values of the Company's other financial instruments at December 31, 2007 and December 31, 2006 respectively are summarized as follows:

	2007					
	Carrying value					
	Held for trading	Available for sale	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets (note 9)	$ 60	$ 63	$ 98	$ -	$ 221	$ 224
Long-term debt (including current portion) (note 11)	-	-	-	2,139	2,139	2,226

	2006					
	Carrying value					
	Held for trading	Available for sale	Loans and receivables	Other financial liabilities	Total	Total fair value
Other assets (note 9)	$ -	$ 66	$ 91	$ -	$ 157	$ 161
Long-term debt (including current portion) (note 11)	-	-	-	2,179	2,179	2,363

19. Financial instruments, continued:

Fair value and classification of financial assets and liabilities, continued

The fair value of the Company's long-term debt is based on determining a required yield for the Company's debt as at December 31, 2007 and 2006. The required yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada bonds that have similar maturities to the Company's debt. The estimated credit spread is based on comparisons to publicly traded debt issues of companies with a similar credit rating as reported publicly by independent financial institutions.

Long term debt (including the current portion) includes COE debentures which are offset by the payments made by the Company into the Sinking Fund. The Company's beneficial interest in the Sinking Fund is a related party transaction and is therefore recorded at the exchange amount. It is not quoted in an active market. As well, fair value of the preferred share interest held in PERH cannot be measured reliably as the preferred shares are not quoted in an active market.

Fair values of financial instruments are determined by reference to quoted bid or ask prices, as appropriate in active markets. In the absence of an active market, fair value of financial instruments is determined consistent with the methods described in note 2(f).

During the year, the Company recorded realized losses of $71 million and unrealized losses of $11 million, in net income, related to changes in fair value of financial instruments required to be classified as held for trading and changes in fair value of financial instruments designated as held for trading respectively.

Credit risk

Accounts receivable consist primarily of amounts due from retail customers including industrial and commercial customers, other retailers and other counterparties. Larger commercial and industrial customer contracts and contracts-for-differences provide for performance assurances including letters of credit. For other retail customers which represent a diversified customer base, credit losses are generally low and the Company provides for an allowance for doubtful accounts to absorb credit losses. The allowance for doubtful accounts is $6 million (2006 - $6 million).

The Company also has credit exposures to large suppliers of electricity and natural gas. The Company mitigates these exposures by dealing with creditworthy counterparties and, where appropriate, taking back appropriate security from the supplier.

Interest rate risk

The Company is exposed to changes in interest rates on its short-term and certain long-term obligations. At December 31, 2007 approximately 87% (2006 - 82%) of the Company's debt was at fixed rates.

19. Financial instruments, continued:

Risk Management

The derivative instruments assets and liabilities used for risk management purposes as described in note 2(f) consist of the following:

	December 31, 2007				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 30	$ 60	$ 14	$ -	$ 104
Non-current	12	82	22	-	116
Derivative instruments liabilities:					
Current	(95)	(33)	(8)	-	(136)
Non-current	(40)	(34)	(4)	-	(78)
	$ (93)	$ 75	$ 24	$ -	$ 6
Net notional amounts:					
Megawatt hours (millions)	-	(2)			
Gigajoules (millions)	-	75			
U.S. foreign exchange			$ (225)		
Contract terms in years	1 to 9	1 to 9	1 to 6		

The Company's natural gas supply contracts run from 2008 to 2016 and market based pricing has been used to determine fair values of these contracts for periods up to 2012. There are limited observable natural gas prices beyond 2012 after which the Company relies on price forecasts prepared by a third party market expert. The natural gas price forecasts for this period range from $7.26/gigajoule (GJ) to $7.35/GJ. A $1.00/GJ change in the natural gas price forecast for the period from 2013 to 2016 would have a $19 million impact on the fair value estimate of these contracts.

19. Financial instruments, continued:

Risk Management, continued

	December 31, 2006				
	Energy		Foreign exchange	Interest rate	
	Cash flow 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)
Net notional amounts:					
Megawatt hours (millions)	(1)	(2)			
U.S. foreign exchange			$ (483)		
Euro foreign exchange			$ 204		
Interest rate swaps				$ 80	
Contract terms in years	1 to 6	1 to 5	1 to 7	< 1	

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. Unrealized and realized gains and losses on foreign exchange derivatives and interest rate derivatives are recorded in energy revenues or foreign exchange gains and losses and net financing expenses, respectively.

Of the $64 million of net losses recorded in accumulated other comprehensive loss, net losses of $45 million (net of income taxes of $20 million) related to derivative instruments designated as cash flow hedges at December 31, 2007 are expected to settle and be reclassified to net income over the next twelve months. The Company's cash flow hedges extend until 2016.

20. Related party balances and transactions:

The related party transactions described below are in the normal course of operations, and are recorded at the exchange value generally based on normal commercial rates, or as agreed to by the parties.

The following summarizes the Company's related party balances and transactions with the COE.

		2007	2006
Balance sheet:			
Accounts receivable	(a)	$ 32	$ 36
Property, plant and equipment	(b)	14	4
Long-term debt (note 11)		243	309
Income statement:			
Revenues: - energy and water sales		$ 25	$ 19
- other	(c)	52	50
Operations, maintenance and administration	(d)	7	8
Franchise fee, property taxes and other taxes	(e)	49	46
Net financing expenses	(f)	54	58

(a) The accounts receivable balance due from the COE includes $28 million (2006 - $29 million) in respect of the negotiated sharing of the earnings of the COE Sinking Fund. During the year, the Company received nil (2006 - nil) of these balances.

(b) Costs of capital construction for water distribution mains and infrastructure.

(c) Revenues from the provision of maintenance, repair and construction services of $45 million (2006 - $42 million) and $7 million for customer billing services (2006 - $8 million).

(d) Includes certain costs of printing services and supplies, mobile equipment services, public works and various other services pursuant to service agreements.

(e) Franchise fee of $39 million (2006 - $37 million) at 0.426 cents per kilowatt-hour (2006 - 0.413 cents per kilowatt hour) for EPCOR Distribution Inc. and at 7.6% (2006 - 7.6%) of qualifying revenues of EPCOR Water Services Inc. Property taxes of $10 million (2006 - $9 million) on property owned within the COE municipal boundaries.

(f) Interest expense on the obligation to the COE.

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

21. Joint ventures:

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

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

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

	2007	2006
Current assets	$ 38	$ 66
Long-term assets	728	584
Current liabilities	56	60
Long-term liabilities	42	57
Revenues[1]	67	75
Expenses[2]	78	80
Net loss	(11)	(5)
Cash flows from operating activities	17	1
Cash flows used in investing activities	(140)	(12)
Cash flows from financing activities	106	12

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

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

Included in the Company's cash and cash equivalents is its proportionate share of cash and cash equivalents which are restricted to use within joint ventures of $14 million (2006 - $16 million).

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

22. Employee future benefits:

Multiemployer defined benefit pension plan and defined contribution pension plan

Over 90% of the Company's employees are either members of the Local Authority Pension Plan or its registered defined contribution plan. Accordingly, the majority of the Company's pension costs and obligations are accounted for as defined contribution plans.

Defined benefit plans

The effective dates for the latest actuarial valuations of the Company's registered and supplemental pension plans were September 1, 2005 and December 31, 2006, respectively. The effective dates of the next valuation for funding purposes are no later than December 31, 2007 for both plans. The date used to measure the plan assets and the accrued benefit obligation was December 31, 2007. The supplemental pension plan is a non-contributory plan that is unfunded at December 31, 2007.

As part of the Company's acquisition of its interest in Power LP, employees who transferred to EPCOR on September 1, 2005 became members of the Company's registered pension plan. The plan provides pension benefits based on an employee's years of service and their highest earnings over three consecutive years of employment. Retirement pensions will be increased annually by a portion of the increase in the Consumer Price Index. Under terms of the Power LP purchase and sale agreement, the previous plan sponsor will transfer the pension liabilities for the Canadian employees and associated assets based on an actuarial valuation. As at December 31, 2007, the actual transfer of assets has not yet occurred as regulatory approval required for transfer of the assets and obligations is still outstanding.

Pension plan benefit costs, assets and obligations

	2007	2006
Costs recognized for the years ended December 31:		
Service cost	$ 3	$ 2
Interest on benefit obligation	1	1
Actual return on assets	-	(1)
Actuarial (gains) losses	(1)	4
Difference between actuarial gain recognized and actual gain on accrued benefit obligation	1	(5)
Defined benefit plans cost	4	1
Defined contribution plans cost	16	15
Net expense	$ 20	$ 16

22. Employee future benefits, continued:

Plan benefit costs, assets and obligations, continued

		2007		2006
Funded status as at December 31:				
Market value of plan assets	$	9	$	8
Accrued benefit obligation		23		21
Funded status – plan deficit		(14)		(13)
Amounts not yet recognized in financial statements:				
Unamortized net losses		3		5
Accrued benefit liability recognized in financial statements	$	(11)	$	(8)
Expected average remaining service life in years – registered pension plan		11		12
Expected average remaining service life in years – supplemental pension plan		12		12

The accrued benefit liability is included in other non-current liabilities along with other employee future benefit liabilities. Other employee future benefit liabilities consist mainly of obligations for benefits provided to employees on long-term disability leaves.

		2007		2006
Reconciliation of accrued benefit obligation:				
Accrued benefit obligation as at January 1	$	21	$	15
Service cost		3		2
Interest cost		1		1
Actual benefits paid		(1)		(1)
Actuarial (gain) loss		(1)		4
Accrued benefit obligation as at December 31	$	23	$	21

		2007		2006
Plan assets:				
Market value of assets as at January 1	$	8	$	7
Contributions		1		1
Benefits paid		-		(1)
Actual return of plan assets (net of expenses)		-		1
Market value of assets as at December 31	$	9	$	8

Total cash payments for pension benefits in 2007, consisting of cash contributed by the Company to the LAPP, other defined contribution and benefit plans and cash payments directly to beneficiaries for its unfunded pension plan, were $16 million (2006 - $15 million).

22. Employee future benefits, continued:

Assumptions:

The significant actuarial assumptions adopted in measuring the corporation's accrued benefit obligations were as follows:

	2007	2006
Accrued benefit obligation as at December 31		
Discount rate	5.25%	5.00%
Rate of compensation increase	4.00%	4.00%
Benefit cost for year ended December 31		
Discount rate	5.25%	5.00%
Rate of compensation increase	4.00%	4.00%
Expected rate of return on plan assets	7.00%	7.00%

Information concerning the Company's registered pension plan's target asset allocation and actual asset allocation is as follows:

	2007		2006	
	Target asset allocation	Asset allocation	Target asset allocation	Asset allocation
Fixed income securities	35%	33%	35%	33%
Equity securities	60%	56%	60%	59%
Other assets	5%	11%	5%	8%
Total	100%	100%	100%	100%

23. Plants under operating leases:

Certain power generation plants operate under PPAs that convey the right to the holder of the agreement to use the related property, plant and equipment. Consequently, these power generation plants, comprised of the Castleton, ManChief, Mamquam, Queen Charlotte, Southport, Roxboro, Kenilworth, Greeley and Williams Lake plants, are accounted for as assets under operating leases. As at December 31, 2007, the carrying value of such property, plant and equipment was $470 million (2006 - $461 million), less accumulated depreciation of $52 million (2006 - $28 million). The Company's revenue pursuant to the arrangements for the year ended December 31, 2007 was $200 million (2006 - $116 million).

24. Contingencies and commitments:

(a) As at December 31, 2007, the Company has committed $12 million to complete the expansion of the EL Smith water treatment facility in 2008 (2006 - $48 million). The Company has committed to the construction of a high-voltage transmission line and substation through 2008 at an estimated total cost of $86 million (2006 - $82 million), of which $45 million has been incurred as at December 31, 2007. The Company has also committed to the purchase of new high efficiency gas-fired electric generating units at an estimated total cost of $283 million (2006 – nil).

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

(c) Under the terms of the acquired Alberta PPAs, the Company is obligated to make monthly payments for fixed and variable costs. The estimated annual total of these payments for 2008 is $149 million. The actual amounts for 2008 and future years may vary from estimates depending on generation volume and scheduled outages. It is expected that the annual payments over the terms of the Alberta PPAs, as described in note 2(k), will range from $88 million to $149 million, adjusted for inflation, other than in the event of a forced outage.

(d) The Company has entered into a number of long-term energy purchase and transportation contracts and operating and maintenance contracts in the normal course of operations. The energy purchase and transportation contracts are based on gross settlement amounts and include both physical sales and purchases. These energy purchase and transportation contracts are also measured at their fair value and recorded on the consolidated balance sheet as derivative instruments assets and liabilities as appropriate.

Approximate future payments under these contracts and under operating leases for premises are as follows:

	Energy purchase and transportation contracts	Operating and maintenance contracts	Operating leases
2008	$ 66	$ 28	$ 3
2009	73	27	3
2010	72	28	3
2011	70	29	3
2012	71	30	1
Thereafter	234	171	5
Total	$ 586	$ 313	$ 18

24. Contingencies and commitments, continued:

(e) The formula for determining energy pricing at the California plants may be retroactively adjusted by the California Public Utilities Commission. The Company estimates that its maximum exposure would be approximately US$28 million. The Company can recover payments related to the Naval facilities from the U.S. Navy under the terms of the steam purchase arrangements. Additionally, the previous owners of the facilities will reimburse the Company for any payments net of recoveries through November 25, 2008. The Company has not recorded a liability as it estimates that an unfavourable outcome is unlikely.

(f) The Company has committed to issue non-interest bearing notes receivable to the non-EPCOR syndicate members involved in the Sundance Swap transaction described in note 4. The commitment relates to funding potential income tax liabilities incurred by the non-EPCOR syndicate members in relation to the transaction. The total estimated loan commitment is $19 million, with annual payments of principal commencing from the date the commitment is called by the non-EPCOR syndicate members through to February 2020. At December 31, 2007, the Company has extended $13 million under such notes and their carrying value of $9 million, after fair value adjustments, is included in other assets.

(g) The Company has entered into multiple agreements with the Town of Chestermere (the Town) to provide upgrading and retrofitting of the Town's water and power infrastructure. The various projects will require a combined capital outlay estimated of $53 million. Furthermore, the Company has agreed to provide financing of the capital outlays for a period of 20 years. The capital outlay is expected to occur at varying intervals based on the Town Council resolutions, as follows:

2008	$	17
2009		4
2010		5
2011		-
2012		-
Thereafter		27
Total	$	53

24. Contingencies and commitments, continued:

(h) On December 6, 2007 the Company entered into a long-term leasing agreement with Station Lands Ltd. to lease head office commercial space in a new office tower to be constructed in Edmonton. The agreement, with an effective date of January 1, 2012, extends for 20 years and provides the Company with three successive five-year renewal options. Under terms of the lease the Company has committed to make annual payments of $10 million for the period of January 1, 2012 through December 31, 2021 and $11 million for the period of January 1, 2022 through December 31, 2031.

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

25. Guarantees:

The Company has issued letters of credit for $357 million (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.

Such letters of credit include $15 million related to prudential support provided by the Company on behalf of the purchaser of certain competitive mass-market contracts in 2004, in addition to $12 million of guarantees issued by the Company for total prudential support at December 31, 2007 of $27 million. The prudential support will be provided until 2009, unless conditions for early termination are met. The prudential support is required by the Alberta Electric System Operator (AESO) and by Alberta gas and electricity distribution service providers in order for the purchaser to participate in the Power Pool of Alberta (Power Pool) and retail energy market. The Power Pool is the market through which all physical electricity exchanges and related financial settlements in Alberta are conducted. AESO is an independent system operator which administers operation of the Power Pool as well as the transmission of all electrical energy through the interconnected electric system in the province of Alberta. The Company's maximum exposure under the prudential support, based on 2007 peak usage and electricity and gas prices and based on maximum volumes under the energy supply agreements, is estimated at approximately $39 million (2006 - $36 million). The estimated maximum exposure under the prudential support agreement will vary proportionately with changes in electricity and gas prices. In return, the Company has retained a security interest in the competitive energy contracts sold, as collateral in the event of default of the various sales transaction agreements. Under the terms of the security interest arrangement, the Company has established separate bank accounts under its control through which billings collected from the contracts and payments of related costs are processed. The Company's use of this cash is restricted to these purposes. At December 31, 2007, $22 million (2006 - $16 million) of the Company's cash resides in these bank accounts. There are no known liabilities under the prudential support agreement as at December 31, 2007.

25. Guarantees, continued:

Under terms of the 2003 disposal of its water heater rental business, the Company has agreed to indemnify the UE Waterheater Operating Trust and/or its subsidiaries for: i) net tax liabilities of Union Energy Inc, prior to closing; ii) any large corporation taxes payable by the Fund from closing to December 31, 2007 up to $13 million; and, iii) any future net tax liability resulting from facts, circumstances and practices in effect on or prior to closing. The indemnity in items i) and ii) expire 90 days following the statutory period for tax reassessment and the indemnity in item iii) expires in 2010. Any known liabilities have been reflected on the consolidated balance sheet.

In the normal course of business, the Company provides financial support and performance assurances including guarantees, letters of credit and surety bonds to third parties in respect of its subsidiaries. The liabilities associated with the underlying subsidiary obligations are included on the consolidated balance sheet.

The Company has no other material guarantee obligations outstanding in respect of third parties at December 31, 2007.

26. 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 U.S. in California, Colorado, New Jersey, New York, North Carolina and Washington.

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.

26. Segment disclosures, continued:

Year ended December 31, 2007

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 905	$ 122	$ 2,395	$ 240	$ 1	$ -	$ 3,663
Intersegment revenues	111	125	22	24	-	(282)	-
Total revenues	1,016	247	2,417	264	1	(282)	3,663
Energy purchases and fuel	312	72	2,149	-	-	(227)	2,306
Operations, maintenance, administration and foreign exchange gain	148	56	80	163	87	(54)	480
Franchise fee, property taxes and other taxes	17	39	-	10	-	-	66
Depreciation, amortization and asset retirement accretion	172	27	30	18	11	-	258
Operating expenses	649	194	2,259	191	98	(281)	3,110
Operating income (loss) before corporate charges	367	53	158	73	(97)	(1)	553
Corporate charges	45	14	26	14	(99)	-	-
Operating income	$ 322	$ 39	$ 132	$ 59	$ 2	$ (1)	$ 553
Total assets	$ 4,045	$ 851	$ 786	$ 761	$ 153	$ (34)	$ 6,562
Capital additions	$ 240	$ 105	$ 12	$ 122	$ 20	$ -	$ 499
Goodwill	$ 183	$ -	$ -	$ 2	$ -	$ -	$ 185

26. Segment disclosures, continued:

Year ended December 31, 2006

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 663	$ 124	$ 1,940	$ 203	$ 1	$ -	$ 2,931
Intersegment revenues	114	134	23	1	-	(272)	-
Total revenues	777	258	1,963	204	1	(272)	2,931
Energy purchases and fuel	102	79	1,745	-	-	(240)	1,686
Operations, maintenance, administration and foreign exchange gain	176	59	79	125	57	(30)	466
Franchise fee, property taxes and other taxes	18	38	-	8	1	-	65
Depreciation, amortization and asset retirement accretion	151	26	28	17	12	-	234
Operating expenses	447	202	1,852	150	70	(270)	2,451
Operating income (loss) before corporate charges	330	56	111	54	(69)	(2)	480
Corporate charges	26	13	22	10	(71)	-	-
Operating income	$ 304	$ 43	$ 89	$ 44	$ 2	$ (2)	$ 480
Total assets	$ 4,102	$ 597	$ 802	$ 636	$ 264	$ (18)	$ 6,383
Capital additions	$ 63	$ 61	$ 11	$ 104	$ 19	$ -	$ 258
Goodwill	$ 181	$ -	$ -	$ 2	$ -	$ -	$ 183

26. Segment disclosures, continued:

Geographic information:

				2007				2006
	Canada	U.S.	Intersegment Eliminations	Total	Canada	U.S.	Intersegment Eliminations	Total
Revenues - external	$ 3,215	$ 448	$ -	$ 3,663	$ 2,720	$ 211	$ -	$ 2,931
Intersegment revenues	33	22	(55)	-	24	10	(34)	-
Total revenues	$ 3,248	$ 470	$ (55)	$ 3,663	$ 2,744	$ 221	$ (34)	$ 2,931
Property, plant and equipment	$ 3,770	$ 446	$ -	$ 4,216	$ 3,444	$ 464	$ -	$ 3,908
Goodwill	$ 151	$ 34	$ -	$ 185	$ 149	$ 34	$ -	$ 183

Intersegment transactions occur in the normal course of operations and are recorded at exchange values which are generally at normal commercial rates. Segments are charged amounts for depreciation on corporate assets that are not allocated to the segments for reporting purposes. All other accounting policies of the segments are the same as those disclosed in note 2.

27. Subsequent events:

On January 31, 2008, the Company completed a $200 million public offering of unsecured medium term note debentures with a coupon rate of 5.80% and maturity date of January 31, 2018. Net proceeds from the offering will be used to repay EPCOR's commercial paper indebtedness and for general corporate purposes.

On March 10, 2008, the Canadian Environment Minister released further information on the proposed new regulatory framework to reduce greenhouse gas emissions and air pollution in Canada that was originally announced on April 26, 2007. If enacted, the proposed framework would require a 20% absolute reduction in greenhouse gases from 2006 levels by 2020 and a 50% reduction in air pollution by 2015. The Company estimates that its costs of compliance with the proposed framework could range from $8 million to $12 million for 2010, escalating proportionately with the increasing emission reduction targets after 2010. The estimated impact is based on the Company's current fleet of generation assets and the costs of contributions to a technology fund outlined in the proposed framework. Actual costs could vary since there are a number of uncertainties associated with this estimate, including but not limited to: whether the regulations enacted in the future vary from the proposed framework as described by the government on March 10, 2008; the extent to which future costs will be recoverable from customers; the future composition of the Company's fleet of generation assets and their future electricity production volumes; the extent and timing of the development of a carbon offset market; whether economically feasible emission–reducing technology emerges; the market price for carbon offset credits and other measures that the Company might undertake to reduce its emissions.

28. Comparative figures:

Certain of the comparative figures have been reclassified to conform with the current year's presentation.