Consolidated Financial Statements of

EPCOR UTILITIES INC.

Years ended December 31, 2006 and 2005

EPCOR UTILITIES INC.

Consolidated Financial Statements

Years ended December 31, 2006 and 2005

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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, 2006 and 2005 and the consolidated statements of income and retained earnings 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, 2006 and 2005 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 23, 2007

EPCOR UTILITIES INC.

Consolidated Statements of Income and Retained Earnings
(In millions of dollars)

Years ended December 31, 2006 and 2005

	2006	2005
Revenues	$ 2,930.8	$ 2,639.6
Operating expenses (income):		
Energy purchases	1,539.7	1,487.3
Fuel	145.8	61.8
Operations, maintenance and administration	470.4	425.1
Franchise fee, property taxes and other taxes	64.8	54.7
Depreciation, amortization and asset retirement accretion (note 5)	233.8	183.5
Foreign exchange gain	(3.7)	(3.2)
	2,450.8	2,209.2
	480.0	430.4
Gain on sale of power purchase arrangement and related transactions (note 4)	378.3	-
Income before financing expenses	858.3	430.4
Financing expenses (note 17)	154.7	131.6
Income from continuing operations before income taxes and amounts in lieu of income taxes and non-controlling interests	703.6	298.8
Income taxes and amounts in lieu of income taxes (note 18)	9.5	101.5
Income from continuing operations before non-controlling interests	694.1	197.3
Non-controlling interests (note 14)	61.6	38.6
Net income from continuing operations	632.5	158.7
Net income from discontinued operations (note 27)	9.6	28.4
Net income	642.1	187.1
Retained earnings, beginning of year	1,765.2	1,700.8
Common share dividends paid	(125.1)	(122.7)
Refundable taxes (note 18)	(37.2)	-
Retained earnings, end of year	$ 2,245.0	$ 1,765.2

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Balance Sheets
(In millions of dollars)

December 31, 2006 and 2005

	2006	2005
Assets		
Current assets:		
Cash and cash equivalents (notes 21 and 25)	$ 260.3	$ 90.0
Accounts receivable	643.0	581.7
Income taxes recoverable	0.9	12.1
Inventories	56.9	43.2
Prepaid expenses	12.0	10.7
Derivative financial instruments asset (note 19)	25.9	57.9
Future income tax asset (note 18)	0.6	2.6
Current assets of discontinued operations (note 27)	2.8	0.5
	1,002.4	798.7
Property, plant and equipment (note 5)	3,906.1	3,698.3
Power purchase arrangements (note 6)	757.5	632.8
Contract and customer rights and other intangible assets (note 7)	201.8	196.4
Derivative financial instruments asset (note 19)	20.2	39.9
Future income tax asset (note 18)	126.9	87.7
Goodwill (note 8)	182.7	148.5
Other assets (note 9)	183.6	58.4
Non-current assets of discontinued operations (note 27)	2.1	3.1
	$ 6,383.3	$ 5,663.8

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

	2006	2005

Liabilities and Shareholder's Equity

	2006	2005
Current liabilities:		
Short-term debt (note 10)	$ 216.3	$ 28.5
Accounts payable and accrued liabilities	603.2	507.3
Income taxes payable	18.6	9.5
Derivative financial instruments liability (note 19)	24.2	59.1
Other current liabilities	13.2	18.0
Future income tax liability (note 18)	91.9	18.7
Current portion of long-term debt (note 11)	62.9	54.4
Current liabilities of discontinued operations (note 27)	4.7	5.0
	1,035.0	700.5
Long-term debt (note 11)	2,115.7	2,028.3
Derivative financial instruments liability (note 19)	26.8	45.2
Other non-current liabilities (note 12)	127.5	131.0
Future income tax liability (note 18)	80.5	98.6
Non-current liabilities of discontinued operations (note 27)	4.6	15.6
	3,390.1	3,019.2
Non-controlling interests (note 14)	750.6	887.2
Shareholder's equity:		
Share capital (note 15)		
Retained earnings	2,245.0	1,765.2
Foreign currency translation adjustment (note 3)	(2.4)	(7.8)
	2,242.6	1,757.4
Contingencies and commitments (note 24)		
Subsequent events (note 28)		
	$ 6,383.3	$ 5,663.8

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Statements of Cash Flows
(In millions of dollars)

Years ended December 31, 2006 and 2005

	2006	2005
Operating activities:		
Net income	$ 642.1	$ 187.1
Items not affecting cash:		
Depreciation, amortization and asset retirement accretion (note 5)	233.8	192.3
Gain on sale of power purchase arrangement and related transactions (note 4)	(378.3)	-
Asset impairment loss (note 5)	3.4	-
Write-down of Clover Bar assets (note 27)	2.1	62.5
Reduction of Clover Bar asset retirement obligations (note 27)	(13.5)	-
Non-controlling interests in Power LP (note 14)	43.5	17.1
Gain on sale of competitive energy contracts (note 3)	-	(8.1)
Other non-cash items	29.6	(3.9)
Future income taxes and amounts in lieu of income taxes	(6.0)	72.9
	556.7	519.9
Change in other non-current items	(14.6)	(40.4)
Change in non-cash operating working capital (note 16)	39.1	(13.3)
	581.2	466.2
Investing activities:		
Property, plant and equipment and other assets	(249.7)	(243.9)
Net change in non-cash working capital	1.2	9.1
Business acquisitions, net of acquired cash (note 3)	(356.4)	(516.6)
Proceeds on sale of Battle River PSA interest (note 4)	336.2	-
Proceeds on sale of Sundance PSA interest (note 4)	17.1	-
Acquisition of interest in Battle River PSA (note 4)	(52.3)	-
Other	9.7	-
	(294.2)	(751.4)
Financing activities:		
Proceeds from issue of short-term debt	209.2	28.5
Repayment of short-term debt	(28.5)	-
Proceeds from issue of long-term debt	405.7	200.0
Repayment of long-term debt	(393.3)	(165.1)
Repayment of capital leases	(1.0)	(0.5)
Redemption of subsidiary preferred shares (note 14)	(150.0)	-
Distributions to non-controlling interests	(85.1)	(20.7)
Issue of limited partnership units of Power LP to non-controlling interests (note 14)	54.9	-
Common share dividends paid	(125.1)	(122.7)
Other	(3.5)	-
	(116.7)	(80.5)
Net increase (decrease) in cash and cash equivalents	170.3	(365.7)
Cash and cash equivalents, beginning of year	90.0	455.7
Cash and cash equivalents, end of year	$ 260.3	$ 90.0

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, with its head office located in Edmonton, Alberta.

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

(b) Rate regulation:

EPCOR provides rate-regulated electric transmission and distribution services to customers within Edmonton and surrounding areas, and supplies electricity under Regulated Rate Tariffs (RRT) to customers in Alberta. EPCOR's electric transmission and distribution operations and its RRT operations are regulated by the Alberta Energy and Utilities Board (AEUB), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta) and the *Hydro and Electric Energy Act* (Alberta). The AEUB administers these acts and regulations regarding tariffs, rates, construction, financing, operations, accounting and service area. The transmission, distribution and RRT businesses operate under cost-of-service regulation, whereby the AEUB 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 2006 return on equity (ROE) for the transmission, distribution, and the non-energy component of the RRT businesses was 8.93% (2005 – 9.50%). Rates charged for energy sold to RRT customers are also approved by the AEUB. 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.

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 11.5% (2005 – 11.5%), 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 Consumer Price Index less an efficiency factor of 50 basis points. The COE Council approved water rates for the five-year period ending March 31, 2007

1. Description of business, continued:

(b) Rate regulation, continued:

in 2001, and 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 AEUB on a complaints-only basis, whereby such communities may apply to the AEUB 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 reasonable rate of return.

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 acquired interest in EPCOR Power L.P. (Power LP). Under GAAP, EPCOR controls Power LP and, therefore, it is a subsidiary of EPCOR.

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

(b) 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. These assets and liabilities are described in notes 2(m) and 12.

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, and the related cost and accumulated depreciation are not removed until the end of the originally estimated useful life. Disposals of land and buildings are recognized in the same manner as those of non-rate-regulated entities.

2. Summary of significant accounting policies:

(b) Regulatory accounting, continued:

(i) *Asset disposals and retirements, continued* - 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.

(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 in 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 an 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.

(c) 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.

2. Summary of significant accounting policies, continued:

(c) Measurement uncertainty, continued:

Various systems and procedures used by third parties to provide load and settlement data to energy retailers in the Alberta and Ontario retail electricity marketplaces may not completely and accurately capture all customer movement, load classification and consumption data. In addition, by regulation, wire service providers 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.

The degree to which revenues are recognized or deferred under the power purchase arrangements described in note 2(o) 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, and for certain disclosures, the Company is required to estimate the fair value of certain assets or obligations. Estimates of fair value are based on depreciable replacement cost or discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate. 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 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.

2. Summary of significant accounting policies, continued:

(c) Measurement uncertainty, continued:

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.

(d) 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(o). 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 cumulative billable contract price per megawatt hour (MWh) and (2) an amount determined by the MWhs made available during the period, multiplied by the average price per MWh over the term of the contract. Any excess of the contract price over the average price is recorded as deferred revenue.

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

2. Summary of significant accounting policies, continued:

(e) Derivative financial instruments:

To reduce its exposure to movements in energy commodity prices, foreign currency exchange rates and interest rate changes, the Company uses various risk management techniques including derivative financial instruments. Derivative financial 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.

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.

Foreign exchange forward contracts are used by the Company to hedge foreign exchange exposures resulting from anticipated transactions denominated in foreign currencies. If hedge criteria are met, gains and losses on these forward contracts are not recorded in the balance sheet and are recognized in the same period and in the same financial statement caption as the gains or losses on the corresponding hedged transactions. For transactions involving property, plant and equipment, the gains or losses on settlement of the forward contract are included in the cost of the asset and depreciated over its estimated useful life.

The Company enters into forward interest rate or swap agreements and option agreements to manage the impact of fluctuating interest rates on existing debt. If hedge criteria are met, these instruments are not recognized in the balance sheet and amounts received or paid under such contracts are matched to the associated cash flows and recorded as an adjustment to interest expense or income.

The Company may use 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. When foreign-currency denominated debt is designated as a hedge of self-sustaining foreign operations, gains and losses on the principal component of the foreign currency long-term debt are deferred and included in a separate component of shareholder's equity. If a hedge is terminated or ceases to be effective, any exchange gain or loss on the hedge which has been deferred up to that date will continue to be included in the separate component of shareholders' equity until there is a reduction in the Company's net investment in the associated foreign operations.

2. Summary of significant accounting policies, continued:

(e) Derivative financial instruments, continued:

The Company may use hedge accounting when there is a high degree of correlation between the hedged 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 hedge on a retroactive and prospective basis. Gains and losses relating to derivative instruments designated as hedges are recognized in the same period and financial statement category as the corresponding hedged transaction. These derivatives are not recorded in the balance sheet.

A hedging relationship is terminated if the hedge relationship ceases to be effective, or if the hedging instrument ceases to exist as a result of its maturity, expiry, sale, termination or cancellation and is not replaced as part of the Company's hedging strategy.

If a hedging relationship is terminated, any cumulative gains or losses arising prior to such time are deferred and recognized in earnings in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in income. If the hedged item matures, expires, or is sold, extinguished or terminated, and the hedged item is no longer probable of occurring, any previous off-balance sheet amounts associated with the hedging instrument are recognized in income along with the corresponding gains or losses recognized on the hedged item.

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instrument are recognized in income in the period of change. The fair value of derivative financial instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter quotations. Fair value amounts reflect management's best estimates considering various factors including closing exchange or over-the-counter quotations, estimates of futures prices and foreign exchange rates, time value and volatility. In illiquid or inactive markets, the Company uses appropriate price modeling to estimate fair value. It is possible that the assumptions used in establishing fair value amounts will differ from actual prices and the impact of such variations could be material.

In addition to its use of derivative financial instruments as described above, the Company in the normal course of the business enters into non-financial or physical commodity contracts which require the future delivery of commodities at fixed prices. These contracts are not recognized in the financial statements until they are settled.

2. Summary of significant accounting policies, continued:

(f) 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.

Effective January 1, 2001, pursuant to the Alberta Payment in Lieu of Tax Regulation (PILOT), the Company was required to pay amounts in lieu of income taxes to the provincial Balancing Pool. Such amounts are levied on income from certain of the Company's generation units that are subject to PPAs as well as income earned on certain retail electricity services, to the extent that such income is not otherwise subject to income taxes under the ITA or the Alberta Corporate Tax Act (ACTA). Amounts in lieu of income taxes are determined in a similar manner as if the subject operations were taxable under the ITA and the ACTA. Following the reorganization of the Generation Services segment on January 3, 2006 and Energy Services segment on January 1, 2007, as described in notes 18 and 28, respectively, the Company will no longer have entities subject to PILOT as they have become subject to the ITA and the ACTA.

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.

(g) 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.

(h) 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:

(i) 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.

(j) 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 in the consolidated balance sheets as Power Purchase Arrangements. Acquired PPAs are recorded at cost and are amortized over their terms on a straight-line basis.

Alberta PPAs, which are comprised of the Battle River PPA and Sundance 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, 2006, the remaining term of the 20-year Sundance PPA is 14 years. The Company is also obligated to make fixed and variable payments to the buyer of the Battle River PPA over the remaining three-year period until sale of the Company's remaining interest in the Battle River PPA is completed, as described in note 4.

2. Summary of significant accounting policies, continued:

(j) Power purchase arrangements, continued:

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. The Company's investment in the Alberta PPAs and its revenues and expenses thereunder 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 three to 22 years from the dates of acquisition. Certain PPAs under which Power LP sells power are accounted for as either operating or capital leases.

(k) 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 20 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.

2. Summary of significant accounting policies, continued:

(l) 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.

(m) Other assets:

Investments in which the Company exercises significant influence are accounted for using the equity method. Other investments are recorded at cost. If there is other than a temporary decline in value of the investment, it is written down to recognize the loss. 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.

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

Regulatory assets represent hearing costs incurred by the Company to support its regulated rate applications, and are amortized over the period of the tariff application approved by the regulator.

(n) Impairment of long-lived assets:

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

2. Summary of significant accounting policies, continued:

(o) 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 in the balance sheet.

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

(p) Asset retirement obligations:

The Company recognizes asset retirement obligations related to its power generation plants and the Genesee coal mine at fair value in the period in which they are incurred, unless the fair value cannot be reasonably determined. When the liability is recognized, a corresponding asset retirement cost is added to the carrying amount of the related long-lived asset, and is depreciated over the estimated useful life of the related 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 legal obligation.

The Company has recorded these asset retirement obligations, 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.

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.

2. Summary of significant accounting policies, continued:

(q) 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 earnings over the lease term.

(r) 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, being three years, from the date of acquisition.

(s) 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 the foreign currency translation adjustment (CTA) account in shareholder's equity until there is a reduction in the Company's net investment in the foreign operations.

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

2. Summary of significant accounting policies, continued:

(t) 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 20% of total employees) who are not otherwise served by LAPP, including employees of new or acquired operations.

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.

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 (PEV). PEV owns eight combined heat and power facilities located in the United States 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 coal pulverization facility in the United States. In addition, PEV provides management and administrative services to PERH and Primary Energy Recycling Corporation (PERC). PERC owns the balance of PERH not owned by PEV.

3. Business acquisitions and disposals, continued:

Acquisition of Primary Energy Ventures LLC, continued:

The total consideration paid was $365.8 million (US$325.7 million) in cash plus acquisition costs of approximately $4.6 million for a total purchase price of $370.4 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	$ 26.4
Property, plant and equipment	139.7
Power purchase arrangements (included in Power LP PPAs)	138.4
Contract rights and other intangible assets	13.7
Future income tax asset, non-current	8.6
Goodwill	33.2
Other assets, including long-term investments of $58.9	98.3
Current liabilities	(15.4)
Capital lease obligations	(78.9)
Other non-current liabilities	(10.2)
	353.8
Cash and cash equivalents	16.6
Fair value of net assets acquired	$ 370.4

Due to the short time frame between closing of the PEV transaction and release of the financial statements, the fair value estimates of certain assets and liabilities will be finalized during the first quarter. Such review could result in material adjustments to the fair value purchase price allocation in subsequent periods.

The results of operations of PEV 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 has 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 of the previously deferred foreign exchange losses 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 $5.6 million is included in foreign exchange gains and losses in the consolidated statements of income.

3. Business acquisitions and disposals, continued:

Acquisition of interest in EPCOR Power L.P. and contract rights:

On September 1, 2005, the Company acquired from TransCanada Corporation (TransCanada) its interest in TransCanada Power, L.P. (now EPCOR Power L.P.). The Company acquired approximately 14.5 million partnership units of Power LP, representing approximately 30.6% of the outstanding units. In addition, the Company acquired 100% of Power LP's General Partner and all of TransCanada's interests in the management and operations agreements governing the operation of Power LP's electricity generation assets.

The total consideration paid was $529.0 million in cash plus acquisition costs of approximately $5.4 million. Upon close of the transaction, TransCanada Power, L.P. was renamed EPCOR Power L.P.

The acquisition's $534.4 million purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values as follows:

Current assets excluding cash and cash equivalents	$ 41.0
Intangible assets with limited lives, included in contract and customer rights and other intangible assets	137.0
Goodwill	145.7
Property, plant and equipment	844.2
Power purchase arrangements (Power LP PPAs)	495.4
Other non-current assets	9.0
Current liabilities	(26.5)
Future income tax liability, non-current	(97.3)
Long-term debt and other non-current liabilities	(466.2)
	1,082.3
Non-controlling interests in net assets	(565.8)
	516.5
Cash and cash equivalents	17.9
Fair value of net assets acquired	$ 534.4

Included in the $137.0 million allocated to contract and customer rights is $84.8 million representing the estimated fair value of various operating and maintenance contracts in which the Company has acquired a 100% interest.

The results of operations of Power LP 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 amount allocated to goodwill is not deductible for income tax purposes.

Other acquisitions and disposals

Other net business acquisitions and disposals resulted in net cash outflows to the Company of $2.6 million (2005 - $0.1 million). The 2005 acquisitions and disposals included the Company's sale of its Ontario mass-market and mid-market electricity contracts and its Alberta mid-market electricity contracts, with a resulting gain on sale of $8.1 million before income taxes.

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 hold 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 $343.3 million on June 5, 2006. The remaining 45% interest will be sold for gross proceeds of $224.0 million, subject to closing adjustments, and recognized when the interest and associated risks and rewards of beneficial ownership are legally transferred to ENMAX over the next four years. The timing of these future sales include the sale of 10% interests closing on each of January 1, 2007, 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 $134.1 million and cash consideration of $52.3 million, for a resulting carrying amount of the 30% interest in the Battle River PSA of $186.4 million prior to its sale to ENMAX.

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 $343.3 million. A pre-tax gain of $329.3 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.

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

In addition to the Sundance Swap, the Company sold an additional interest in the Sundance PSA (the Sundance Extension) to non-EPCOR syndicate members for cash consideration of $17.5 million and notes receivable of $40.4 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, 2006, the non-current portion of the notes receivable of $37.2 million is recorded in other assets and the current portion of $1.9 million is recorded in accounts receivable. The pre-tax gain recognized on sale of the Sundance Extension, after final purchase price adjustments, was $49.0 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.

The proceeds and resulting gain arising from the sale and related transactions 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	$ 343.3	$ -	$ 17.5	$ 360.8
Cash paid to acquire Battle River PSA interest from non-EPCOR syndicate member	-	(52.3)	-	(52.3)
Cash proceeds (payments) for purchase price adjustments	0.9	-	(0.4)	0.5
Less cash proceeds on Battle River PSA relating to operating income between May 1 effective date and June 5 closing date	(6.0)	-	-	(6.0)
Less disposal costs	(2.0)	-	-	(2.0)
Net cash proceeds received (consideration paid)	336.2	(52.3)	17.1	301.0
Notes receivable from non-EPCOR syndicate members on Sundance Extension sale	-	-	40.4	40.4
Total proceeds (payments)	336.2	(52.3)	57.5	341.4
Increase in carrying value of Battle River PSA arising from Sundance Swap and purchased interest, respectively	134.1	52.3	-	186.4
Carrying value of disposed 55% interest in Battle River PSA	(121.4)	-	-	(121.4)
Carrying value of disposed interest in Sundance PSA	(19.6)	-	(8.5)	(28.1)
Gain on sale before income taxes	$ 329.3	$ -	$ 49.0	378.3
Future income taxes				51.0
Gain on sale after income taxes				$ 327.3

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

Refundable taxes of $42.4 million, which arose from taxable capital gains on the sale of Battle River PPA and interest in the PSA, have been charged to retained earnings. The income taxes and refundable taxes of $51.0 million and $42.4 million, respectively, have increased the current future income tax liability in the consolidated balance sheets.

5. Property, plant and equipment:

				2006
	Composite depreciation rates	Cost	Accumulated depreciation	Net Book Value
Generation plants and equipment	3.6%	$ 3,187.7	$ 671.5	$ 2,516.2
Water treatment and distribution	2.0%	1,137.0	287.6	849.4
Electricity transmission and distribution	3.1%	908.1	328.3	579.8
Retail systems and equipment	10.5%	99.9	46.1	53.8
Corporate information systems and equipment	11.9%	108.1	66.0	42.1
		5,440.8	1,399.5	4,041.3
Contributions:				
Generation plants and equipment	16.2%	(7.6)	(1.0)	(6.6)
Water treatment and distribution	1.4%	(428.0)	(73.8)	(354.2)
Electricity transmission and distribution	2.8%	(100.3)	(35.0)	(65.3)
		(535.9)	(109.8)	(426.1)
Assets under capital lease	7.5%	71.2	1.4	69.8
Land	None	93.8	-	93.8
Construction work in progress	None	127.3	-	127.3
		$ 5,197.2	$ 1,291.1	$ 3,906.1

5. Property, plant and equipment, continued:

				2005
	Composite depreciation rates	Cost	Accumulated depreciation	Net Book Value
Generation plants and equipment	2.7%	$ 3,037.6	$ 584.1	$ 2,453.5
Water treatment and distribution	1.9%	1,040.0	262.8	777.2
Electricity transmission and distribution	3.2%	905.8	340.5	565.3
Retail systems and equipment	11.4%	106.3	48.0	58.3
Corporate information systems and equipment	12.9%	97.3	53.8	43.5
		5,187.0	1,289.2	3,897.8
Contributions:				
Generation plants and equipment	-	(5.8)	-	(5.8)
Water treatment and distribution	1.4%	(391.9)	(68.2)	(323.7)
Electricity transmission and distribution	2.3%	(96.4)	(33.3)	(63.1)
		(494.1)	(101.5)	(392.6)
Assets under capital lease	20.6%	1.9	0.3	1.6
Land	None	89.7	-	89.7
Construction work in progress	None	101.8	-	101.8
		$ 4,886.3	$ 1,188.0	$ 3,698.3

5. Property, plant and equipment, continued:

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

	2006	2005
Continuing operations:		
Depreciation on assets in service	$ 186.5	$ 152.0
Accretion of asset retirement obligations	4.6	3.3
Gain on settlement of mine reclamation costs	(7.1)	(7.0)
Decommissioning charges	0.2	0.3
Amortization of contributions	(9.6)	(7.4)
Amortization of PPAs	49.8	29.7
Amortization of contract and customer rights and other intangible assets	9.0	12.4
Amortization of other assets	0.4	0.2
	233.8	183.5
Depreciation and amortization - discontinued operations	-	8.8
	$ 233.8	$ 192.3

Interest and AFUDC capitalized to property, plant and equipment for 2006 is $5.1 million (2005 - $6.8 million).

In December, 2006, the Company recorded an impairment loss of $3.4 million in respect of property, plant and equipment relating to the Kingsbridge II wind power development project in Ontario. The book value of the assets developed to December, 2006 was determined to exceed its net recoverable amount. This determination was made following the Company's decision to re-examine the project design and schedule and terminate arrangements with certain suppliers in 2007 due to the status of required local and provincial approvals and uncertainties about the timeline for certain future approval processes. Contract termination costs, estimated at $5.9 million, will be recorded in the period that the contract terminations take place. The impairment loss is recorded in operations, maintenance and administration expense in the consolidated statements of income and retained earnings and is included in the results of the Generation segment.

6. Power purchase arrangements:

			2006			2005
	Cost	Accumulated amortization	Net Book Value	Cost	Accumulated amortization	Net Book Value
Alberta PPAs	$ 240.2	$ 66.3	$ 173.9	$ 247.9	$ 97.5	$ 150.4
Power LP PPAs	633.4	49.8	583.6	495.2	12.8	482.4
	$ 873.6	$ 116.1	$ 757.5	$ 743.1	$ 110.3	$ 632.8

7. Contract and customer rights and other intangible assets:

			2006			2005
	Cost	Accumulated amortization	Net Book Value	Cost	Accumulated amortization	Net Book Value
Contract rights	$ 136.4	$ 5.3	$ 131.1	$ 121.9	$ 1.5	$ 120.4
Customer rights	106.3	56.2	50.1	106.3	51.3	55.0
Water rights	15.0	0.4	14.6	15.0	0.1	14.9
Lease rights	6.1	0.1	6.0	6.1	-	6.1
	$ 263.8	$ 62.0	$ 201.8	$ 249.3	$ 52.9	$ 196.4

8. Goodwill

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

	2006	2005
Balance, beginning of year	$ 148.5	$ -
Goodwill acquired on Power LP acquisition (note 3)	-	145.7
Goodwill acquired on PEV acquisition (note 3)	33.2	-
Goodwill acquired on other business acquisitions	1.0	2.8
	$ 182.7	$ 148.5

9. Other assets:

	2006	2005
Cost		
Investment in PERH	$ 56.9	$ -
Loans and other long-term receivables	56.0	25.2
Net investment in lease	35.1	-
Debenture issue expenses	21.7	18.7
Portfolio investments	8.9	11.8
Deferred charges	12.2	8.2
Regulatory asset	0.7	2.7
	191.5	66.6
Accumulated amortization		
Debenture issue expenses	6.7	4.6
Deferred charges	1.2	3.6
	7.9	8.2
	$ 183.6	$ 58.4

9. Other assets, continued:

In connection with the PEV 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 two-month period ended December 31, 2006, equity losses of $1.2 million included in operations, maintenance and administration expense, and $1.0 million in dividends have been recorded against the common share investment in PERH. At December 31, 2006, 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 $26.4 million.

Through the PEV 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 $1.4 million is included in accounts receivable. Financing income for the two-month period ended December 31, 2006 of $0.5 million is included in revenues.

10. Short-term debt:

	2006	2005
Power LP bridge acquisition credit facility	$ 216.3	$ -
Commercial paper	-	28.5

The Power LP bridge acquisition credit facility is comprised of an unsecured, non-revolving US$185.6 million facility due on October 27, 2007. Under the terms of this credit facility, the Company can borrow by way of prime loans, US base rate loans, LIBOR loans and bankers' acceptances. At December 31, 2006, the facility had an interest rate of approximately 5.8%. The bridge acquisition credit facility was established solely for financing the acquisition of PEV described in note 3.

Bank lines of credit in addition to the Power LP bridge acquisition facility described above are unsecured and are available to the Company up to an amount of $1,496.3 million, comprised of committed amounts of $1,451.3 as described in note 11 and uncommitted amounts of $45.0 million. Letters of credit totaling $247.8 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 $500.0 million and is backed by the committed bank lines.

11. Long-term debt:

	2006	2005
Obligation to The City of Edmonton, net of sinking fund (note 20):		
Due in 1-5 years at 10.70%[1] (2005 – 10.92%[1])	$ 126.6	$ 150.0
Due in 6-10 years at 9.21%[1] (2005 - 9.58%[1])	84.4	128.7
Due in 11-15 years at 8.75%[1] (2005 - 8.75%[1])	70.7	75.0
Due in 16-20 years at 7.01%[1] (2005 - 7.01%[1])	27.3	28.2
	309.0	381.9
Debentures, at 6.20%, due in 2008	200.0	200.0
Debentures, at 6.95%, due in 2010	200.0	200.0
Debentures, at 6.60%, due in 2011	200.0	200.0
Debentures, at 6.75%, due in 2016	130.0	130.0
Debentures, at 6.80%, due in 2029	150.0	150.0
Debentures, at 5.65%, due in 2035	200.0	200.0
Power LP unsecured senior notes (US$190.0), at 5.9%, due in 2014	224.6	224.5
Power LP unsecured senior notes, at 6.0%, due in 2036	210.0	-
Power LP secured term loan, at 11.3%, due in 2010	4.8	5.7
Non-recourse financing:		
Brown Lake Project, at 8.7%, due in 2016	7.6	8.1
Joffre Cogeneration Project, at fixed and floating rates, due in 2020	59.4	73.4
Three-year extendible credit facility, at floating rates (US$84.5)	-	98.3
Power LP revolving extendible credit facilities, at floating rates, due in 2009	149.4	-
Power LP credit facility, at floating rates, due in 2009	-	209.1
Power LP bridge acquisition credit facility (US$44.0), at floating rates, due in 2009	51.3	-
Obligations under capital leases	82.5	1.7
	2,178.6	2,082.7
Less: current portion	62.9	54.4
	$ 2,115.7	$ 2,028.3

[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 By-law authorization. The outstanding debentures are a direct, unconditional obligation of The City of Edmonton. The Company's obligation to The City of Edmonton matches The City's obligation pursuant to the debentures. All of the 8.75% debentures, maturing in the year 2018 and totaling $70.7 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 City of Edmonton. Except for the subordinated debt, the obligation to The City of Edmonton will rank at least equal to all future debt that may be issued by the Company.

The Company makes annual payments into The Sinking Fund of The City of Edmonton 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 sinking fund issue, the payment obligation ceases on maturity of the debt.

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 $210.0 million issued during 2006 are due in June 2036 with interest payable semi-annually. The net proceeds from the notes offering were used to repay the Power LP's previous $210.0 million credit facility.

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 $15.1 million (2005 - $14.4 million). The loan bears interest at an annual rate of approximately 11.3% and matures on July 15, 2010.

11. Long-term debt, continued:

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 $40.0 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% (2005 - 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 $113.8 million (2005 - $117.8 million). Brown Lake Project financing is secured by a charge against project assets which have a carrying value of $12.4 million (2005 - $12.6 million).

Three-year extendible credit facility

On August 1, 2006, the Company repaid $87.4 million (US$77.0 million) which was the full amount outstanding under its three-year extendible credit facility. In the first quarter of 2006, $8.6 million (US$7.5 million) of the facility had been repaid. The credit facility had been used to hedge the Company's net investment in self-sustaining foreign operations, which was sold to Power LP from another subsidiary of the Company on August 1, 2006, as described in note 3.

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

An $800.0 million extendible syndicated bank revolving credit facility, consisting of three-year and five-year tranches of $400.0 million each, is available to the Company. At December 31, 2006, the Company had $nil outstanding under this facility.

Two-year extendible credit facilities

Unsecured two-year credit facilities of $100.0 million each for a total of $400.0 million, committed to 2008, are available to the Company. At December 31, 2006, the Company had $nil outstanding under the two-year extendible credit facilities.

Power LP revolving extendible credit facilities

Unsecured three-year credit facilities of $100.0 million each for a total of $200.0 million, committed to September 2009 and October 2009 respectively, are available to the Company. At December 31, 2006, the Company had $136.4 million (US$117.0 million) and $13.0 million outstanding under the three-year extendible credit facilities (2005 - $ nil). Under the terms of the facilities, the Company can obtain advances by way of prime loans, US base rate loans, LIBOR loans and bankers' acceptances. At December 31, 2006, the facilities had an average interest rate of approximately 5.6 per cent.

11. Long-term debt, continued:

Power LP bridge acquisition credit facility

The Power LP bridge acquisition facility is unsecured and non-revolving and is due on October 27, 2009. At December 31, 2006, the loan bears interest at approximately 5.8%. This long-term bridge acquisition facility was used to finance the acquisition of PEV, along with the short-term bridge facility described in note 10.

Capital lease obligations

The capital lease obligation relates primarily to three facilities located on US Naval bases in California. The capital lease obligations reflect interest rates ranging from 4.9% to 9.1% and are repaid over a term ending in 2020.

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:

2007	$	58.6
2008		237.6
2009		218.8
2010		225.8
2011		219.6

Minimum capital lease payments

Future minimum lease payments under capital leases by year and in aggregate are as follows:

2007	$	11.5
2008		11.1
2009		11.2
2010		12.2
2011		7.8
Thereafter		59.6
Total minimum lease payments		113.4
Less: amount representing interest ranging from 4.9% to 9.1%		(30.9)
Present value of net minimum lease payments		82.5
Less: current portion of capital lease obligations		(4.3)
Capital lease obligation net of current portion	$	78.2

12. Other non-current liabilities:

	2006	2005
Asset retirement obligations (note 13)	$ 87.0	$ 79.9
Deferred availability incentives on generation units operating under PPAs	2.5	23.5
Employee future benefit liabilities	17.1	15.5
Regulatory provision for plant decommissioning	2.1	7.0
Long-term incentive plan liability	10.2	4.6
Contract liabilities, net	8.3	-
Other	0.3	0.5
	$ 127.5	$ 131.0

13. Asset retirement obligations:

A reconciliation between the opening and closing asset retirement obligation balances, excluding amounts related to the Clover Bar discontinued operations, is provided below:

	2006	2005
Balance, beginning of year	$ 87.5	$ 67.1
Assumption of PEV and Power LP obligations (note 3)	1.4	16.6
Liabilities incurred	8.8	8.2
Liabilities settled	(7.8)	(7.7)
Asset retirement accretion expense	4.6	3.3
Change in foreign exchange rates	0.2	-
	94.7	87.5
Less: current portion in accounts payable and accrued liabilities	7.7	7.6
	$ 87.0	$ 79.9

The Company estimates the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $368.9 million, calculated using inflation rates ranging from 2% to 3%. The expected timing for settlement of the obligations is between 2007 and 2084. The majority of the payments to settle the obligations are expected to occur between 2032 and 2045 for the power generation plants, and between 2007 and 2011 for sections of the Genesee coal mine. Discount rates ranging from 5.1% 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:

	2006	2005
Non-controlling interests in Power LP	$ 43.5	$ 17.1
Preferred share dividends paid by subsidiary companies	17.0	21.5
Preferred share issue costs recognized on redemption of preferred shares	1.1	-
	$ 61.6	$ 38.6

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

	2006	2005
Non-controlling interests in Power LP, beginning of year	$ 541.5	$ -
Non-controlling interests at acquisition date	-	565.8
Partnership units issued to non-controlling interests	54.9	-
Earnings attributable to non-controlling interests	43.5	17.1
Distributions to non-controlling interests	(86.1)	(41.4)
Non-controlling interests in Power LP, end of year	553.8	541.5
Preferred shares issued by subsidiary companies, beginning of year	345.7	345.7
Redemption of preferred shares	(148.9)	-
Preferred shares issued by subsidiary companies, end of year	196.8	345.7
	$ 750.6	$ 887.2

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

14. Non-controlling interests, continued:

Preferred shares issued by subsidiary companies

During 2002 and 2001, subsidiaries of the Company issued 8 million cumulative, redeemable First Preferred Shares, Series I with dividends payable on a quarterly basis at the annual rate of $1.375 per share, and 6 million cumulative, redeemable First Preferred Shares, Series A with dividends payable quarterly at the annual rate of $1.4375 per share. The dividend rates are fixed for the first five years from the respective dates of issue. On each five-year anniversary of their respective issue, the dividend rates on the Series 1 and Series A shares will be reset as determined by the Company at not less than 80% and 90%, respectively, of the five-year Government of Canada Yield. On each five-year anniversary of their respective issue, the Series I and Series A shares may be converted to Series II and Series B shares, respectively, at the option of the holders. The Series II and Series B shares have substantially similar terms to the Series I and Series A shares except that they pay floating, adjustable, cumulative dividends, if declared. The preferred shares are redeemable, at $25.00 per share, by the subsidiary companies at certain times, but are not retractable by the holders. The subsidiary companies loaned the proceeds from the preferred share issues to other subsidiaries of EPCOR in exchange for interest-bearing intercompany promissory notes.

On June 30, 2006, the subsidiary of the Company which had issued the 6 million Cumulative Redeemable Perpetual First Preferred Shares, Series A (Preferred Shares) during 2001 redeemed all of its issued Preferred Shares at par for $150.0 million cash.

The carrying value of the Preferred Shares prior to their redemption by the Company was $148.9 million, reflecting $150.0 million less issue costs, net of tax, of $1.1 million which were incurred when the preferred shares were issued in 2001. The $1.1 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 City of Edmonton.

The Company, under terms of an intercompany promissory note issued between its subsidiary companies as described in note 14, has covenanted that it will not pay any cash dividends on its common shares at any time that the payment of interest on these notes is deferred.

16. Change in non-cash operating working capital:

		2006		2005
Accounts receivable	$	(44.6)	$	(139.0)
Income taxes recoverable		11.2		3.7
Inventories		(7.5)		(3.0)
Prepaid expenses		0.3		3.4
Accounts payable and accrued liabilities		75.4		115.5
Income taxes and amounts in lieu of income taxes payable		9.1		3.9
Other current liabilities		(4.8)		2.2
	$	39.1	$	(13.3)

17. Financing expenses:

		2006		2005
Interest on long-term debt	$	163.4	$	140.8
Other interest income		(6.8)		(3.7)
		156.6		137.1
Amortization of debt issue costs		2.0		1.3
Interest on capital lease obligations		1.2		-
Capitalized interest and AFUDC		(5.1)		(6.8)
	$	154.7	$	131.6

Interest paid (received) during the year, excluding capitalized interest, was as follows:

		2006		2005
Interest paid on long-term debt	$	167.1	$	141.6
Other interest received		(5.0)		(3.7)
	$	162.1	$	137.9

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

	2006	2005
Current income taxes and amounts in lieu of income taxes	20.8	46.0
Future income taxes and amounts in lieu of income taxes	(11.3)	55.5
	$ 9.5	$ 101.5

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:

	2006	2005
Income from continuing operations before income taxes and amounts in lieu of income taxes and non-controlling interests	$ 703.6	$ 298.8
Statutory income tax rates	32.50%	33.62%
Income taxes and amounts in lieu of income taxes at statutory rates	228.7	100.5
Increase (decrease) resulting from:		
Net future income tax assets recognized on corporate restructuring within the Generation segment	(117.1)	-
Non-taxable portion of capital gains	(88.8)	-
Income exempt from income taxes at statutory rate	(60.8)	(42.8)
Adjustment for enacted changes in income tax laws and rates	35.2	-
Valuation allowance	(2.2)	-
Large Corporations Tax	-	3.9
Income tax related to prior periods	(0.4)	1.9
Non-taxable (non-deductible) amounts	9.2	(0.6)
Adjustment of amounts in lieu of income taxes on settlement	-	38.1
Other	5.7	0.5
	$ 9.5	$ 101.5

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

Income taxes and amounts in lieu of income taxes paid in 2006 were $2.2 million (2005 - $43.2 million including amounts relating to discontinued Clover Bar operations).

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

	2006	2005
Future income tax asset:		
Cumulative eligible capital	$ 99.5	$ 53.7
Property, plant and equipment – differences in net book value and undepreciated capital cost	36.5	24.3
Construction in progress	2.9	25.5
Incentive income from generation units operating under PPAs – deferred for accounting purposes	-	11.1
Non-capital losses carried forward	56.6	40.6
Asset retirement obligations	23.7	31.3
Derivative financial instruments	1.1	35.2
Long-term debt	1.1	2.1
Capital losses carried forward	9.0	-
Other	10.0	6.9
	240.4	230.7
Future income tax liability:		
Deferred income from partnership	107.5	29.3
Property, plant and equipment – differences in net book value and undepreciated capital cost	90.8	111.7
Power purchase arrangements	42.4	47.1
Contract rights and other intangible assets	23.5	24.0
Asset retirement obligation assets	10.0	9.9
Derivative financial instruments	7.1	34.3
Other non-current assets and liabilities	4.0	1.4
	285.3	257.7
Net future tax (liability) asset	$ (44.9)	$ (27.0)

Presented in the balance sheet as follows:		
Current assets	$ 0.6	$ 2.6
Non-current assets	126.9	87.7
Current liabilities	(91.9)	(18.7)
Non-current liabilities	(80.5)	(98.6)
	$ (44.9)	$ (27.0)

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

At December 31, 2006, the Company has non-capital losses carried forward of approximately $190.1 million (2005 - $94.4 million), of which $32.8 million (2005 - $30.3 million) relate to certain U.S. subsidiaries. These losses expire between 2009 and 2026. The Company also has taxable capital losses of approximately $19.6 million (2005 - nil) which carry forward indefinitely.

Refundable taxes of $37.2 million included in retained earnings are comprised of $42.4 million arising from the sale of the Battle River PPA and related transactions as described in note 4, less $5.2 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.

Corporate income tax rate reductions

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 $16.1 million charge to consolidated net income and a corresponding reduction in net future income tax assets and liabilities.

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 Income Tax Act (Canada) (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 $117.1 million. The resulting future income tax assets will be reduced over time, as the underlying income tax deductions are utilized to reduce taxable income.

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

Settlement of goodwill valuation with Alberta Revenue

On May 3, 2005, the Company reached a settlement with Alberta Revenue, Tax and Administration (Alberta Revenue), as agent for Alberta's Balancing Pool with respect to the value of goodwill for purposes of PILOT. In July 2003, Alberta Revenue notified the Company that it was their view that the value of goodwill determined by the Company for purposes of PILOT was overstated at the date the Company first became subject to the PILOT. As a result of the settlement upon the value of goodwill, the Company reduced its future income tax asset associated with the goodwill by $28.3 million and recognized $9.8 million of current income taxes, resulting in a charge to income taxes and amounts in lieu of income taxes expense of $38.1 million in 2005.

19. Financial instruments:

Fair value of off-balance sheet contracts for differences

The following table provides the estimated fair value of derivative instruments designated as hedges, being off-balance sheet contracts-for-differences, as at December 31, 2006 and 2005:

			2006			2005
	Notional quantity (millions of megawatt hours)	Term in years	Fair value asset (liability)	Notional quantity (millions of megawatt hours)	Term in years	Fair value asset (liability)
Electricity sales	8.5	1 to 5	(150.6)	10.9	1 to 5	$ (130.0)
Electricity purchases	7.8	1 to 5	90.6	3.6	1 to 5	35.5

Deferred gains and losses on derivative financial instruments

Included in non-current derivative financial instruments assets is $11.5 million (2005 - $14.4 million) relating to deferred losses on certain financial instruments which did not satisfy all the required conditions for hedge accounting upon initial application on January 1, 2004 of the Canadian Institute of Chartered Accountants Accounting Guideline 13 – Hedging Relationships. Under this guideline, these unrealized losses are recognized in income over the remaining term of the respective financial instruments.

Included in non-current derivative financial instruments liability is $5.6 million of unrealized gains relating to the Company voluntarily de-designating foreign exchange forward contracts as hedges on April 1, 2006. These unrealized gains are recognized in income over 6 years, being the remaining period over which the previously hedged items are expected to occur.

19. Financial instruments, continued:

Fair value of other financial assets (liabilities)

	2006	2005
Long-term debt (excluding capital lease obligations)	$ (2,360.4)	$ (2,397.9)

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, 2006 and 2005. 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.

The fair values of all other financial assets and financial liabilities, including capital lease obligations, are not materially different from their carrying values.

Credit risk

Accounts receivable consist 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 $5.8 million (2005 - $6.1 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, 2006 approximately 82% (2005 - 83%) of the Company's debt was at fixed rates.

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 City of Edmonton.

		2006	2005
Balance sheet:			
Accounts receivable	(a)	$ 36.4	$ 29.9
Property, plant and equipment	(b)	4.2	2.6
Long-term debt – see note 12		309.0	381.9
Income Statement:			
Revenues: - energy and water sales		$ 18.7	$ 18.8
- other	(c)	50.3	46.9
Operations, maintenance and administration	(d)	7.6	6.5
Franchise fee, property taxes and other taxes	(e)	45.9	44.6
Financing expenses	(f)	58.1	62.8

(a) The accounts receivable balance due from The City of Edmonton includes $29.0 million (2005 - $26.9 million) in respect of the negotiated sharing of the earnings of The City of Edmonton Sinking Fund. During the year, the Company received $ nil (2005 - $ 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 $42.3 million (2005 - $39.6 million) and $8.0 million for customer billing services (2005 - $7.3 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 $36.7 million (2005 - $34.6 million) at 0.413 cents per kilowatt-hour (2005 - 0.412 cents per kilowatt hour) for EPCOR Distribution Inc. and at 7.6% (2005 - 7.6%) of qualifying revenues of EPCOR Water Services Inc. Property taxes of $9.2 million (2005 - $10.0 million) on property owned within The City of Edmonton municipal boundaries.

(f) Interest expense on the obligation to The City of Edmonton.

Included in the Company's revenues is $0.6 million for the provision of management services by Power LP to PERC under a long-term management agreement. At December 31, 2006, accounts receivable includes $0.3 million due from PERC.

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 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:

	2006	2005
Current assets	$ 65.7	$ 36.1
Long-term assets	583.7	592.5
Current liabilities	59.7	18.0
Long-term liabilities	57.3	68.9
Revenues[1]	74.8	71.0
Expenses[2]	79.7	85.2
Net income	(4.9)	(14.2)
Cash flows from operating activities	1.0	(42.0)
Cash flows from (used in) investing activities	(12.4)	(27.2)
Cash flows (used in) from financing activities	12.3	71.7

[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 $15.8 million (2005 - $13.3 million).

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 other registered defined contribution plan. Accordingly, the majority of the Company's pension costs and obligations are accounted for as defined contribution plans.

22. Employee future benefits, continued:

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 required 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, 2006. Where applicable, the measurement was obtained by extrapolating the results from the previous actuarial valuations to the measurement date. The supplemental pension plan is a non-contributory plan that is unfunded at December 31, 2006.

As part of the Company's acquisition of its interest in Power LP, as described in note 3, 59 employees who became employees of EPCOR on September 1, 2005 became members of the Company's registered pension plan. The Company will continue to provide pension benefits based on the same provisions as the previous plan sponsor for a period of at least two years. The pension plan benefits are 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, 2006, 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

	2006	2005
Costs recognized for the years ended December 31:		
Service cost	$ 1.7	$ 1.0
Interest on benefit obligation	0.8	0.4
Actual return on assets	(0.5)	(0.1)
Actuarial losses in 2006	3.5	1.4
Difference between actuarial gain recognized and actual gain on accrued benefit obligation in 2006	(4.5)	(0.4)
Defined benefit plans cost	1.0	2.3
Defined contribution plans cost	14.9	12.5
Net expense	$ 15.9	$ 14.8

22. Employee future benefits, continued:

Plan benefit costs, assets and obligations, continued

	2006	2005
Funded status as at December 31:		
Market value of plan assets	$ 7.6	$ 6.8
Accrued benefit obligation	20.7	15.4
Funded status – plan deficit	(13.1)	(8.6)
Amounts not yet recognized in financial statements:		
Unrecognized past service cost	(0.3)	-
Unamortized net losses	4.9	-
Accrued benefit liability recognized in financial statements	$ (8.5)	$ (8.6)
Amortization period in years	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 are mainly comprised of obligations for benefits provided to employees on long-term disability leaves.

	2006	2005
Reconciliation of accrued benefit obligation:		
Accrued benefit obligation as at January 1	$ 15.4	$ 5.0
Estimated obligation on transfer of employees relating to Power LP acquisition	-	7.8
Past service cost adjustment	-	(0.4)
Service cost	1.7	1.0
Interest cost	0.8	0.4
Actual benefits paid	(0.7)	-
Actuarial loss	3.5	1.6
Accrued benefit obligation as at December 31	$ 20.7	$ 15.4

	2006	2005
Plan assets:		
Market value of assets as at January 1	$ 6.8	$ 0.8
Estimated assets on transfer of employees relating to Power LP acquisition	-	5.8
Contributions	0.8	-
Benefits paid	(0.6)	-
Actual return of plan assets (net of expenses)	0.6	0.2
Market value of assets as at December 31	$ 7.6	$ 6.8

Total cash payments for pension benefits in 2006, 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 $14.6 million (2005 - $11.9 million).

22. Employee future benefits, continued:

Assumptions:

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

	2006	2005
Accrued benefit obligation as at December 31		
Discount Rate	5.0%	5.0%
Rate of compensation increase	4.0%	4.0%
Benefit Cost for year ended December 31		
Discount Rate	5.0%	5.0%
Rate of compensation increase	4.0%	4.0%
Expected rate of return on plan assets	7.0%	7.0%

Due to the pending transfer of plan assets from the previous sponsor's plan assets, the asset composition is not available as at December 31, 2006.

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, 2006, the carrying value of such property, plant and equipment was $456.0 million (2005 - $394.8 million), less accumulated depreciation of $23.3 million (2005 - $6.6 million). The Company's revenue pursuant to the arrangements for the year ended December 31, 2006 was $116.0 million (four month period ended December 31, 2005 - $29.6 million).

24. Contingencies and commitments:

(a) In 2005, the Company entered into a contract with the Ontario Power Authority (OPA) to construct the Kingsbridge II wind-powered generation facility in Ontario at an original estimated cost of $300 million. As described in note 5, the Company is currently re-examining the project design and schedule and is terminating arrangements with certain suppliers. As a result, the Company has written off certain project development costs and will recognize charges associated with terminating certain contracts in 2007. The Company is not in breach of the contract.

24. Contingencies and commitments, continued:

(b) As at December 31, 2006, the Company has committed $47.8 million over the next two years for the expansion of the EL Smith water treatment facility (2005 - $4.6 million). The Company has also committed to the construction of a high-voltage transmission line and substation over the next two years at an estimated cost of $82.4 million (2005 - $ nil).

(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 2007 is $141 million. The actual amounts for 2007 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(j), will range from $77 million to $141 million, adjusted for inflation, other than in the event of a forced outage.

(d) The Company has entered into a number of long-term gas supply and transportation contracts in the normal course of operations. Approximate future payments under these contracts and under operating leases for premises are as follows:

	Gas supply and transportation contracts	Operating leases	Total
2007	$ 53.8	$ 2.5	$ 56.3
2008	59.8	2.9	62.7
2009	62.8	2.7	65.5
2010	61.7	2.5	64.2
2011	67.3	0.2	67.5
Thereafter	343.7	0.2	343.9
Total	$ 649.1	$ 11.0	$ 660.1

(e) In July 2004, NAL Resources Limited (NAL) and Devon Canada Corporation (Devon) commenced actions against Power LP claiming the gas supply contracts under which NAL and Devon sell gas to Power LP for its Tunis, Ontario power plant have been frustrated as of January 1, 2003 due to an alleged inability to determine escalations in the commodity charge for gas under such agreements. NAL and Devon additionally seek monetary damages based on referenced spot prices for natural gas deliveries. During 2006, the Company accrued a total of $6.1 million for potential additional payments to gas suppliers, including NAL and Devon, based on publicly available price escalation information. Of the accrued potential additional payments, $4.1 million relates to periods prior to 2006. Discussions toward settlement of the claims have taken place and are expected to continue. Management believes there was no frustration of the contracts and that any amounts claimed above the accrued amounts are without merit.

24. Contingencies and commitments, continued:

(f) The formula for determining energy pricing at the Power LP's California plants may be retroactively adjusted by the California Public Utilities Commission. The Company estimates that its maximum exposure would be approximately US$22.4 million for the three plants located on Navy bases and US$6.0 million for the Oxnard facility. For the three plants located on Navy bases, any payment made can be recovered from the U.S. Navy under the terms of the steam supply agreements. For the Oxnard facility, the Company believes retroactive application of pricing formulas should not be applied as the Company has reached a settlement agreement with Southern California Edison (SCE). To the extent that, the Company is required to pay any amount for the California plants through November 25, 2008, the previous owner of these facilities is obligated to reimburse the Company for 80% of such payments, net of any amounts recovered from third parties. The Company has not recorded a liability as it deems an unfavourable outcome unlikely.

(g) 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 $19.5 million, with annual payments of principal commencing from the date the commitment is called by the non-EPCOR syndicate members through to February 2020. The Company anticipates it will extend approximately $13.4 million under such notes in the first quarter of 2007.

(h) On October 31, 2006 the Canadian Minister of Finance announced proposed measures that will, if enacted, result in certain publicly traded partnerships being taxed on an equivalent basis as corporations commencing in 2011. As a result, the Company's Power LP subsidiary, as a publicly traded partnership, would become subject to income taxes on some or all of its operations in 2011. The proposed measures were not substantively enacted at December 31, 2006. The Company is reviewing the potential financial effect of the proposed measures.

(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 $247.8 million (2005 - $153.9 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 $24.8 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 $9.9 million of guarantees issued by the Company for total prudential support at December 31, 2006 of $34.7 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 December 31, 2006 electricity and gas prices and based on maximum volumes under the energy supply agreements, is estimated at approximately $35.6 million (2005 - $40.0 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, 2006, $15.8 million (2005 - $2.1 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, 2006.

Under terms of the 2003 disposal of its water heater rental business, the Company has agreed to indemnify the UE Waterheater Income Fund and/or its subsidiaries for: i) liabilities related to assets sold prior to closing of the sale; ii) net tax liabilities of Union Energy Inc, prior to closing; iii) any large corporation taxes payable by the Fund from closing to December 31, 2007 up to $13.0 million; and, iv) any future net tax liability resulting from facts, circumstances and practices in effect on or prior to closing. The indemnity in item iv) expires in 2010. Any known liabilities have been reflected in 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 in the consolidated balance sheet.

The Company has no other material guarantee obligations outstanding in respect of third parties at December 31, 2006.

26. Segment disclosures:

Effective January 1, 2006, EPCOR changed its measure of profit or loss for segment reporting purposes from net income to operating income which is income before non-operating gains and losses, financing expenses, income taxes and amounts in lieu of income taxes, non-controlling interests and net income from discontinued operations. This measure represents how performance is measured by management effective January 1, 2006. Shared corporate charges are now identified separately from other operating costs. In addition, the Transportation business was transferred to the Water segment from the Distribution and Transmission segment. Transportation provides competitive contract-based commercial services related to installation, maintenance and repair of streetlighting, traffic signal, light rail transit and trolley facilities. The comparative results have been restated to conform with the new basis of segment presentation.

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

Generation

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

Distribution and Transmission

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

Energy Services

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

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, 2006

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 662.9	$ 123.7	$ 1,940.3	$ 203.4	$ 0.5	$ -	$ 2,930.8
Intersegment revenues	114.0	133.7	22.5	1.3	-	(271.5)	-
Total revenues	776.9	257.4	1,962.8	204.7	0.5	(271.5)	2,930.8
Energy purchases and fuel	101.9	78.7	1,744.8	-	-	(239.9)	1,685.5
Operations, maintenance, administration and foreign exchange gain	175.8	59.8	79.0	125.2	57.0	(30.1)	466.7
Franchise fee, property taxes and other taxes	17.9	37.6	0.2	8.1	1.0	-	64.8
Depreciation, amortization and asset retirement accretion	150.8	25.9	28.4	16.5	12.2	-	233.8
Operating expenses	446.4	202.0	1,852.4	149.8	70.2	(270.0)	2,450.8
Operating income (loss) before corporate charges	330.5	55.4	110.4	54.9	(69.7)	(1.5)	480.0
Corporate charges	26.0	12.9	21.6	10.6	(71.1)	-	-
Operating income	$ 304.5	$ 42.5	$ 88.8	$ 44.3	$ 1.4	$ (1.5)	$ 480.0
Total assets	$ 4,101.5	$ 597.4	$ 802.4	$ 635.8	$ 264.2	$ (18.0)	$ 6,383.3
Capital additions	$ 55.1	$ 61.0	$ 10.8	$ 104.2	$ 18.6	$ -	$ 249.7

26. Segment disclosures, continued:

Year ended December 31, 2005 (Restated)

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 467.6	$ 77.9	$ 1,880.8	$ 212.7	$ 0.6	$ -	$ 2,639.6
Intersegment revenues	110.9	133.6	25.5	1.1	-	(271.1)	-
Total revenues	578.5	211.5	1,906.3	213.8	0.6	(271.1)	2,639.6
Energy purchases and fuel	112.7	48.8	1,628.4	-	-	(240.8)	1,549.1
Operations, maintenance, administration and foreign exchange gain	127.5	56.7	82.2	136.6	49.2	(30.3)	421.9
Franchise fee, property taxes and other taxes	10.7	36.1	0.2	7.7	-	-	54.7
Depreciation, amortization and asset retirement accretion	92.2	24.4	39.7	15.3	11.9	-	183.5
Operating expenses	343.1	166.0	1,750.5	159.6	61.1	(271.1)	2,209.2
Operating income (loss) before corporate charges	235.4	45.5	155.8	54.2	(60.5)	-	430.4
Corporate charges	19.0	11.1	22.9	8.8	(61.8)	-	-
Operating income	$ 216.4	$ 34.4	$ 132.9	$ 45.4	$ 1.3	$ -	$ 430.4
Total assets	$ 3,715.1	$ 538.4	$ 787.9	$ 541.0	$ 92.3	$ (10.9)	$ 5,663.8
Capital additions	$ 118.2	$ 61.4	$ 7.9	$ 50.6	$ 5.8	$ -	$ 243.9

26. Segment disclosures, continued:

Geographic information:

	2006				2005			
	Canada	U.S.	Intersegment Eliminations	Total	Canada	U.S.	Intersegment Eliminations	Total
Revenues - external	$ 2,719.6	$ 211.2	$ -	$ 2,930.8	$ 2,506.7	$ 132.9	$ -	$ 2,639.6
Intersegment revenues	24.5	9.6	(34.1)	-	20.2	28.8	(49.0)	-
Total revenues	$ 2,744.1	$ 220.8	$ (34.1)	$ 2,930.8	$ 2,526.9	$ 161.7	$ (49.0)	$ 2,639.6
Capital assets	$ 3,484.5	$ 421.6	$ -	$ 3,906.1	$ 3,359.9	$ 338.4	$ -	$ 3,698.3

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. Discontinued operations:

On April 1, 2005, Alberta's Balancing Pool, as the PPA holder, advised the Company of its decision to terminate the Clover Bar power purchase arrangement effective September 30, 2005, at which time the plant was closed and decommissioning commenced.

As of December 31, 2006, the total remaining cost of decommissioning was estimated at $4.7 million. This is a lower estimate than previously recognized in the asset retirement obligation associated with this facility. The resulting reduction of $13.5 million was recorded as an addition to income from discontinued operations.

The results of operations of the Clover Bar plant have been reported as discontinued operations in the consolidated statements of income and retained earnings. The related assets and liabilities, as detailed below, have been reclassified as current and non-current assets and liabilities of discontinued operations in the consolidated balance sheets.

27. Discontinued operations, continued:

		2006		2005
Current assets of discontinued operations				
Accounts receivable and other	$	2.8	$	0.5
Non-current assets of discontinued operations				
Property, plant and equipment	$	2.1	$	3.1
Current liabilities of discontinued operations				
Asset retirement obligations and other	$	4.7	$	5.0
Non-current liabilities of discontinued operations				
Asset retirement obligations	$	-	$	15.6
Future income tax liability		4.6		-

Operating results from the discontinued Clover Bar plant for the years ended December 31, 2006 and 2005, which include income taxes and amounts in lieu of income taxes directly attributable to the discontinued operations, are as follows:

		2006		2005
Revenues	$	2.8	$	48.5
Operating expenses		-		20.7
Operating income		2.8		27.8
PPA termination payment		-		82.7
Write-down of property, plant and equipment and other assets		(2.1)		(62.5)
Reduction of asset retirement obligations		13.5		-
Net income from discontinued operations before income taxes		14.2		48.0
Income taxes		4.6		19.6
Net income from discontinued operations	$	9.6	$	28.4

28. Subsequent events:

Battle River PPA sale

On January 1, 2007, the Company sold an additional 10% interest in the Battler River PPA pursuant to the sales agreement described in note 4 for cash proceeds of $59.0 million. The Company expects to record a gain of approximately $37.6 million in the first quarter of 2007 as a result of this sale.

Corporate restructuring

On January 1, 2007, the Company reorganized certain subsidiaries within its Energy Services segment. As a result of the reorganization, the Company expects to recognize future income tax assets of approximately $11.9 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.

Keephills 3

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

29. Comparative figures:

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