Consolidated Financial Statements of

EPCOR UTILITIES INC.

Years ended December 31, 2005 and 2004

EPCOR UTILITIES INC.

Consolidated Financial Statements

Years ended December 31, 2005 and 2004

Auditors' Report 1

Financial Statements:

Consolidated Statements of Income and Retained Earnings 2

Consolidated Balance Sheets 3

Consolidated Statements of Cash Flows 5

Notes to Consolidated Financial Statements 6

KPMG LLP
Chartered Accountants
10125 – 102 Street
Edmonton AB T5J 3V8
Canada

Telephone (780) 429-7300
Fax (780) 429-7379
Internet www.kpmg.ca

AUDITORS' REPORT TO THE SHAREHOLDER OF EPCOR UTILITIES INC.

We have audited the consolidated balance sheets of EPCOR Utilities Inc. as at December 31, 2005 and 2004 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, 2005 and 2004 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 28, 2006

KPMG LLP, a Canadian limited liability partnership is the Canadian member firm of KPMG International, a Swiss cooperative.

EPCOR UTILITIES INC.

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

Years ended December 31, 2005 and 2004

	2005	2004
Revenues	$ 2,698.8	$ 2,594.6
Operating expenses:		
Energy purchases	1,487.3	1,577.6
Fuel	61.8	38.0
Operations, maintenance and administration	481.1	397.8
Franchise fee, property taxes and other taxes	54.7	48.6
Depreciation, amortization, and asset retirement accretion (note 5)	183.5	152.0
	2,268.4	2,214.0
Operating income before financing expenses	430.4	380.6
Financing expenses (note 17)	131.6	110.6
Income from continuing operations before income taxes and amounts in lieu of income taxes and non-controlling interests	298.8	270.0
Income taxes and amounts in lieu of income taxes (note 18)	101.5	65.8
Income from continuing operations before non-controlling interests	197.3	204.2
Non-controlling interests (note 13)	38.6	21.5
Net income from continuing operations	158.7	182.7
Net income from discontinued operations (note 28)	28.4	15.3
Net income	187.1	198.0
Retained earnings, beginning of year	1,700.8	1,623.3
Common share dividends paid	(122.7)	(120.5)
Retained earnings, end of year	$ 1,765.2	$ 1,700.8

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Balance Sheets
(In millions of dollars)

December 31, 2005 and 2004

	2005	2004
Assets		
Current assets:		
Cash and cash equivalents (note 25)	$ 90.0	$ 455.7
Accounts receivable (note 4)	588.8	424.0
Inventories	43.2	31.7
Prepaid expenses	10.7	9.6
Derivative financial instruments asset (note 19)	57.9	3.7
Future income tax asset (note 18)	2.6	0.8
Current assets of discontinued operations (note 28)	0.5	10.5
	793.7	936.0
Property, plant and equipment (note 5)	3,698.3	2,744.7
Power purchase arrangements (note 6)	632.8	167.3
Contract and customer rights and other intangible assets (note 7)	196.4	67.5
Derivative financial instruments asset (note 19)	39.9	17.3
Future income tax asset (note 18)	87.7	175.3
Goodwill (notes 3 and 27)	148.5	-
Other assets (note 8)	58.4	29.2
Non-current assets of discontinued operations (note 28)	3.1	64.7
	$ 5,658.8	$ 4,202.0

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

	2005	2004
Liabilities and Shareholder's Equity		
Current liabilities:		
Short-term debt (note 9)	$ 28.5	$ -
Accounts payable and accrued liabilities	502.7	337.9
Income taxes payable	9.5	5.6
Derivative financial instruments liability (note 19)	59.1	7.4
Other current liabilities	18.0	8.9
Future income tax liability (note 18)	18.7	30.3
Current portion of long-term debt (note 10)	54.0	131.0
Current liabilities of discontinued operations (note 28)	5.0	1.7
	695.5	522.8
Long-term debt (note 10)	2,027.0	1,479.3
Derivative financial instruments liability (note 19)	45.2	21.0
Other non-current liabilities (note 11)	132.3	113.5
Future income tax liability (note 18)	98.6	0.4
Non-current liabilities of discontinued operations (note 28)	15.6	26.3
	3,014.2	2,163.3
Non-controlling interests (note 13)	887.2	345.7
Shareholder's equity:		
Share capital (note 14)		
Retained earnings	1,765.2	1,700.8
Foreign currency translation adjustment (note 15)	(7.8)	(7.8)
	1,757.4	1,693.0
Contingencies and commitments (note 24)		
Subsequent event (note 29)		
	$ 5,658.8	$ 4,202.0

See accompanying notes to consolidated financial statements.

EPCOR UTILITIES INC.

Consolidated Statements of Cash Flows
(In millions of dollars)

Years ended December 31, 2005 and 2004

	2005	2004
Operating activities:		
Net income	$ 187.1	$ 198.0
Items not affecting cash:		
Depreciation, amortization, and asset retirement accretion (note 5)	192.3	162.5
Write-down of Clover Bar assets (note 28)	62.5	-
Non-controlling interests in EPCOR Power L.P. (note 13)	17.1	-
Gain on sale of competitive energy contracts (note 27)	(8.1)	(7.7)
Loss on sale of interest in the Frederickson plant (note 27)	-	12.4
Other non-cash items	(3.9)	12.7
Future income taxes and amounts in lieu of income taxes	72.9	7.3
	519.9	385.2
Decrease in deferred amounts receivable	-	21.7
Change in other non-current items	(40.4)	(42.0)
Change in non-cash operating working capital (note 16)	(13.3)	73.5
	466.2	438.4
Investing activities:		
Property, plant and equipment and other assets	(243.9)	(220.4)
Net change in non-cash working capital	9.1	7.0
Acquisition of interest in Power LP and contract rights, net of acquired cash (note 3)	(516.5)	-
Proceeds on sale of interest in the Frederickson plant (note 27)	-	104.9
Proceeds on sale of investment in UE Waterheater Income Fund (note 28)	-	51.3
Other business acquisitions and disposals, net (note 27)	(0.1)	10.4
	(751.4)	(46.8)
Financing activities:		
Increase in short-term debt	28.5	-
Proceeds from issue of long-term debt	200.0	-
Principal payments on long-term debt	(163.4)	(86.1)
U.S. financing, short-term debt	-	(123.2)
U.S. financing, long-term debt	(1.7)	4.2
Distributions to non-controlling interests	(20.7)	-
Common share dividends paid	(122.7)	(120.5)
Net decrease in deferred utility obligation	-	(24.8)
Other	(0.5)	-
	(80.5)	(350.4)
Net (decrease) increase in cash and cash equivalents	(365.7)	41.2
Cash and cash equivalents, beginning of year	455.7	414.5
Cash and cash equivalents, end of year	$ 90.0	$ 455.7

See accompanying notes to consolidated financial statements.

1. Description of business:

(a) Nature of operations:

EPCOR Utilities Inc. (the Company or EPCOR) provides rate-regulated and non-rate-regulated electric utility services, natural gas services, water utility services, and complementary commercial services. The Company's head office is in Edmonton, Alberta and has operations in Alberta, Ontario, British Columbia, and in the U.S. in the states of Washington, Idaho, Colorado and New York.

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

(b) Rate regulation:

EPCOR's generation units in Alberta that commenced operations before January 1, 1996 are operated under Power Purchase Arrangements (PPAs), which were developed through a process overseen by the Alberta Energy and Utilities Board (AEUB) and accounted for as described in note 2(e).

EPCOR provides rate-regulated electric transmission and distribution services to customers within the City of 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 AEUB. The AEUB administers acts and regulations regarding tariffs, rates, construction, financing, operations, accounting and service area.

The Electric Utilities Act (EUA) governs the exchange of all electric energy through the interconnected electric system in the province of Alberta. The Power Pool of Alberta (Power Pool) is the market through which all physical electricity exchanges and related financial settlements in Alberta are conducted. Generators submit offers to the Power Pool for the supply of energy, and retailers submit demand bids to the Power Pool for their energy requirements. The Power Pool dispatches generators to meet the demand from distributors, and conducts all financial settlements from its market operations. Pursuant to the EUA, operation of the Power Pool as well as administration of the transmission of all electrical energy through the interconnected electric system in the province of Alberta is administered by an independent system operator, the Alberta Electric System Operator (AESO).

EPCOR's water services are regulated by The City of Edmonton Council for water rates to charge customers within The City of Edmonton. Since The City of Edmonton is the Company's shareholder, its regulator for water services is a related party. The rates are performance-based whereby the tariff is intended to allow the Company to recover its costs and earn a fair rate of return while also providing an incentive to manage costs below the inflationary adjustment built into the rates. The Company determines the water rates to charge other municipalities. Any Alberta municipality served by the Company may apply to the AEUB to resolve disputes in connection with rates, tolls or charges.

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.

These consolidated financial statements include the accounts of EPCOR, its subsidiaries, and its proportionate share of jointly controlled entities.

They include the accounts of the Company's acquired interest in EPCOR Power L.P. (Power LP) from the date of its acquisition on September 1, 2005, as described in note 3. Under generally accepted accounting principles, EPCOR controls Power LP and, therefore, is a subsidiary of EPCOR. The acquisition has been accounted for as a business combination with full consolidation of the financial position and results of Power LP from the date of acquisition.

Effective January 1, 2005, EPCOR adopted the new standard for consolidation of variable interest entities (VIEs). The standard requires enterprises to identify VIEs in which they have a variable interest, determine whether they are the primary beneficiary of such entities and, if so, consolidate them in the financial statements. The Company has identified and evaluated its interests which potentially would be subject to the provisions of the new accounting standard for the consolidation of VIEs. The Company has concluded that the impact of this new standard is not material to the consolidated financial statements.

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 generally accepted accounting principles 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(n) and 11.

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

(i) When an asset is retired or disposed of, 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.

(ii) 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 any resulting gain or loss in current operating results at the time of retirement or disposition.

2. Summary of significant accounting policies, continued:

(b) Regulatory accounting, continued:

(iii) The Company capitalizes an allowance for funds used during construction (AFUDC) to provide for the cost of capital invested in rate-regulated construction activities. AFUDC 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 in similar circumstances in the absence of rate regulation.

(c) Measurement uncertainty:

The preparation of the Company's financial statements, in accordance with generally accepted accounting principles, 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.

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 are challenged to 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 the associated processes and systems are complex and are used by the Company to estimate electricity revenues and costs, including unbilled consumption. 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 – see note 24(h).

The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is based on a number of factors including the aging of receivables, historical write-offs within customer groups, assessments of the collectibility of amounts from individual customers and general economic conditions.

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

For determining potential asset impairments and certain disclosures, the Company is required to estimate the fair value of certain assets or obligations. Estimates of fair value are mainly based on 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.

2. Summary of significant accounting policies, continued:

(c) Measurement uncertainty, continued:

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

Depreciation and amortization, which also includes amounts for future decommissioning costs, is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of common life characteristics of common assets.

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

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

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

2. Summary of significant accounting policies, continued:

(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 in the year, 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.

Revenues from the Company's Alberta generation units operating under Power Purchase Arrangements (PPAs) are recognized in accordance with the terms of the arrangements with expected incentives and penalties recorded as described in note 2(e).

Revenues from generation units developed or acquired by the Company after January 1, 2001, including from the generation units acquired through the acquisition of the interest in Power LP (note 3) which operate under long-term sales contracts, are recognized on the accrual basis at the time of delivery of electricity to the customer. Revenues from the Curtis Palmer generation plant are recognized at the lower of (1) the 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.

Revenues from acquired PPAs are recognized as the electricity is generated and available for delivery.

(e) Generation units operating under Power Purchase Arrangements (PPAs):

PPAs are a form of long-term sales arrangement between the owner of a generation unit and the buyer of the PPA. Effective January 1, 2001, in accordance with Alberta provincial legislation, generation units in Alberta owned by the Company began operating under PPAs. Under the terms of the PPAs, the Company receives fixed and variable payments designed to cover the forecast costs of operating its generation units, including amounts in lieu of income taxes, as well as a reasonable return. Since the criteria for rate-regulated accounting are no longer met, these generation units are accounted for using generally accepted accounting principles for non-rate-regulated operations.

Following termination of the Clover Bar PPA on September 30, 2005, as described in note 28, only two of the Company's Alberta generation units (Genesee 1 and Genesee 2) continue to operate under a PPA, which expires in the year 2020.

2. Summary of significant accounting policies, continued:

(e) Generation units operating under PPA's, continued:

The target levels of generation availability set out in the PPAs recognize that the generation units will experience planned and forced outages over the terms of the PPAs. The Company records the electricity revenue from the generation units under PPAs at the long-term price of power embedded in the PPAs, including expected incentives and penalties for operating above or below specified availability targets set out in the PPA. Under this approach, incentives for the current period are deferred on a unit by unit basis 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 for an individual generation unit, 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 for each generation unit will change due to revisions to the long-term outlook of unit 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. During 2004, the Company revised its estimated generation availability over the term of the PPAs. The impact of this change in estimate on the 2004 financial statements was a $56.1 million reduction in deferred availability incentive included in other non-current liabilities and an increase to revenues of $56.1 million. The net after-tax earnings impact was $37.1 million.

(f) 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. Gains and losses on these derivatives that qualify as hedges (described below) are not recorded on 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.

2. Summary of significant accounting policies, continued:

(f) Derivative financial instruments, continued:

The Company uses 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 the Company realizes a reduction of its net investment in the associated foreign operations.

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 on 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 on 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 uses 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, including its risk management objectives and its assessment of the effectiveness of the hedge at the hedge's inception and on an ongoing 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.

2. Summary of significant accounting policies, continued:

(f) Derivative financial instruments, continued:

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, is sold, extinguished or terminated, and the hedged item is no longer probable of occurring, any previously 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 realized and unrealized changes in fair value are recognized in income in the period in which they occur in the same financial statement caption as the gains or losses on the corresponding hedged transactions. The fair value of derivative financial instruments reflects changes in the level of commodity market prices, interest, 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 also 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:

(g) Income taxes:

The Company and its subsidiaries are municipally owned, and were exempt from income taxes prior to January 1, 1999. Effective January 1, 1999, under the Income Tax Act (Canada), 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 per cent 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 Income Tax Act (Canada). 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, the Company is required to pay amounts in lieu of income taxes to the provincial Balancing Pool. Such amounts are levied on income from 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 Income Tax Act (Canada) or the Alberta Corporate Tax Act. Amounts in lieu of income taxes are determined in a similar manner as if the subject operations were taxable under the Income Tax Act (Canada) or the Alberta Corporate Tax Act. There were no amounts in lieu of income taxes prior to January 1, 2001.

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.

2. Summary of significant accounting policies, continued:

(h) Cash and cash equivalents:

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

(i) Inventories:

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

(j) Property, plant and equipment:

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

Depreciation and amortization on assets 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.

When an asset of the Company's rate-regulated operations is retired or disposed of, its original cost is charged to accumulated depreciation, with no gain or loss reflected in income. Non-rate-regulated operations include any gain or loss in current operating results.

Decommissioning charges on rate-regulated transmission and water assets are provided 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. Upon the retirement of these 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.

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 capitalizes AFUDC during construction for rate-regulated operations – see note 2(b).

2. Summary of significant accounting policies, continued:

(k) Power purchase arrangements:

Acquired power purchase arrangements (PPAs) 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 acquisition described in note 3 (Power LP PPAs). Acquired PPAs are reflected on 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 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 Company is obligated to make fixed and variable payments to the owners of the underlying generation units over the terms of the Alberta PPAs, which range from 13 to 20 years. At December 31, 2005, the remaining terms of the Alberta PPAs range from 8 to 15 years. Such amounts are recorded as operating expenses as incurred.

The Company purchased the Alberta PPAs with an equity syndicate under syndication agreements. Under the terms of the agreements, the syndicate members effectively 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 portion of the purchase price for Power LP that has been allocated to existing long-term sales contracts, commonly referred to as Power Purchase Arrangements, under which revenue is earned by Power LP's generation units at the date of the Company's acquisition of its interest in Power LP. The cost allocated to the Power LP PPAs is amortized over the remaining terms of the sales contracts, which range from three to 22 years. Certain PPAs under which Power LP sells power are accounted for as operating leases and, accordingly, the related property, plant and equipment are accounted for as assets under operating leases.

2. Summary of significant accounting policies, continued:

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

Contract rights represent the cost assigned to contractual agreements acquired through business acquisitions. Contract rights consist of management and operations agreements acquired through the Power LP transaction described in note 3, lease rights acquired in 2005 to secure land lease agreements to be used for future wind power projects in Ontario, and a long-term sales contract for the electricity generated by a plant acquired in 2000. Contract rights are amortized on a straight-line basis over the expected contract lives which range from 5 to 70 years. The lease rights will be amortized on a straight-line basis over the terms of the respective leases, commencing when wind power assets to be constructed on the sites are commissioned for service.

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 5 to 20 years depending on the expectation of benefit from the underlying customer group.

Other intangible assets include the cost assigned to water rights acquired by way of the Power LP acquisition described in note 3. The assigned cost was determined based on the estimated fair value at the date of acquisition of the beneficial unprotected right to the use of the water for the operation of the acquired hydroelectric power generation plants. The water rights are amortized over the remaining lives of the associated property, plant and equipment.

(m) Goodwill:

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the net assets acquired based on their fair values. Goodwill is allocated to the Company's reporting units that are expected to benefit from the synergies of the business combination. 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 arise earlier. There was no impairment of goodwill at December 31, 2005.

(n) Other assets:

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

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.

2. Summary of significant accounting policies, continued:

(n) Other assets, continued:

Deferred charges consist of costs incurred to acquire environmental emission credits, which are amortized into operating expenses as power is generated at the respective generating units. Deferred charges also include the realized loss on a bond forward contract associated with a long-term debt issue, which has been deferred and is charged to financing expenses over the term of the related debt.

Long-term receivables are comprised of amounts due from customers in excess of one year from the balance sheet date.

Regulatory assets represent hearing costs incurred by the Company to support its regulated rate applications, and is recovered or amortized as permitted or required by the AEUB.

(o) 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 its carrying value to exceed the total undiscounted cash flows expected from its use and eventual disposition. An impairment loss, if any, would be recorded as the excess of the carrying value 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. During 2005, an impairment loss was recognized in relation to the Clover Bar discontinued operations (note 28). No other material impairment losses were recognized during 2005 and 2004.

(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. No amount has been recorded for certain of the Company's hydroelectric power plants as it was not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the requirements.

2. Summary of significant accounting policies, continued:

(p) Asset retirement obligations, continued:

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 estimated decommissioning costs on its rate-regulated assets as approved by its regulator – see note 2(j).

(q) Investments in joint ventures:

The Company and the coal mine operator at the Genesee plant site each have a 50 per cent 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 40 per cent interest in the Joffre Cogeneration Project, a 50 per cent interest in the Genesee Phase 3 Project, and a 50 per cent interest in the Taylor's Coulee Chute Hydro Project, all located in the province of Alberta.

The Company retains a 50.15 per cent remaining interest in its Frederickson generation plant after the disposal on April 29, 2004 of a 49.85 per cent interest therein as described in note 27.

The investments in joint ventures are accounted for using the proportionate consolidation method. Under this method, the Company records its proportionate share of assets, liabilities, revenue and expenses of the joint ventures.

(r) Foreign currency translation:

The Company's self-sustaining foreign operations are accounted for under the current-rate method. Under this method, assets and liabilities are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Revenues and expenses are translated at average exchange rates prevailing during the period. Resulting unrealized gains or losses are accumulated and reported as "Foreign currency translation adjustment" in shareholder's equity until the Company realizes a reduction of its net investment in the foreign operations.

Foreign currency transactions of Canadian operations and integrated foreign operations are translated to Canadian dollars using the temporal method. Under this method, exchange rates in effect at the transaction date are applied to foreign currency transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at rates of exchange prevailing at the end of the reporting period. The resulting foreign exchange gains and losses are included in administration expense.

2. Summary of significant accounting policies, continued:

(s) 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 the few 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 (EARSL) of employees active at the date of amendment. The excess of the net cumulative unamortized actuarial gain or loss over ten per cent of the greater of the accrued benefit obligation and the market value of plan assets are amortized over the estimated average remaining service period of the active employees.

The Company maintains a long-term incentive plan for certain employees, which is based on appreciation of the Company's value over a specified term. The Company accrues such obligations based on the estimated increase in equity value applied to the rights granted under the plan.

3. 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. (Power LP). The Company acquired approximately 14.5 million units of Power LP, representing approximately 30.6 per cent of the outstanding units. In addition, the Company acquired 100 percent 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. Power LP owns a portfolio of 11 power generation plants in Canada and the United States. The generation plants include natural gas, small-scale hydro and bio-mass facilities.

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:

Cash and cash equivalents	$ 17.9
Other current assets	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)
	1,100.2
Non-controlling interests in net assets	(565.8)
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 per cent interest.

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

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.

4. Accounts receivable:

	2005	2004
Accounts receivable	$ 475.5	$ 302.5
Estimated unbilled consumption (notes 2(c) and 24(h))	101.3	104.5
Income taxes recoverable	12.0	17.0
	$ 588.8	$ 424.0

Accounts receivable represents amounts billed and due from customers. Estimated unbilled consumption represents an estimate of the value of customer energy and water consumption not yet billed.

5. Property, plant and equipment:

				2005
	Composite depreciation rates	Cost	Accumulated depreciation	Net Book Value
Generation plants and equipment	2.7%	$ 3,039.2	$ 584.3	$ 2,454.9
Water treatment and distribution	1.9%	1,040.3	262.9	777.4
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
		5,188.9	1,289.5	3,899.4
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)
Land	-	89.7	-	89.7
Construction work in progress	-	101.8	-	101.8
		$ 4,886.3	$ 1,188.0	$ 3,698.3

5. Property, plant and equipment, continued:

				2004
	Composite depreciation rates	Cost	Accumulated depreciation	Net Book Value
Generation plants and equipment	3.4%	$ 1,821.0	$ 521.2	$ 1,299.8
Water treatment and distribution	1.9%	977.6	241.6	736.0
Electricity transmission and distribution	3.2%	837.5	322.7	514.8
Retail systems and equipment	11.2%	102.6	41.8	60.8
Corporate information systems and equipment	13.1%	94.6	51.2	43.4
		3,833.3	1,178.5	2,654.8
Contributions:				
Generation plants and equipment	-	(1.3)	-	(1.3)
Water treatment and distribution	1.4%	(377.0)	(63.0)	(314.0)
Electricity transmission and distribution	2.2%	(86.1)	(32.1)	(54.0)
		(464.4)	(95.1)	(369.3)
Land	-	76.6	-	76.6
Construction work in progress	-	382.6	-	382.6
		$ 3,828.1	$ 1,083.4	$ 2,744.7

5. Property, plant and equipment, continued:

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

	2005	2004
Continuing operations:		
Depreciation on assets in service	$ 152.0	$ 130.4
Accretion of asset retirement obligations	3.3	2.9
Gain on settlement of mine reclamation costs	(7.0)	(6.7)
Decommissioning charges	0.3	0.4
Amortization of contributions	(7.4)	(6.9)
Amortization of PPAs	29.7	18.5
Amortization of contract and customer rights and other intangible assets	12.4	12.1
Amortization of other assets	0.2	1.3
	183.5	152.0
Depreciation and amortization - discontinued operations	8.8	10.5
	$ 192.3	$ 162.5

Interest and AFUDC capitalized to property, plant and equipment for 2005 is $6.8 million (2004 - $25.1 million).

6. Power purchase arrangements:

			2005			2004
	Cost	Accumulated amortization	Net Book Value	Cost	Accumulated amortization	Net Book Value
Alberta PPAs	$ 247.9	$ 97.5	$ 150.4	$ 247.9	$ 80.6	$ 167.3
Power LP PPAs	495.2	12.8	482.4	-	-	-
	$ 743.1	$ 110.3	$ 632.8	$ 247.9	$ 80.6	$ 167.3

7. Contract and customer rights and other intangible assets:

			2005			2004
	Cost	Accumulated amortization	Net Book Value	Cost	Accumulated amortization	Net Book Value
Contract rights	$ 129.9	$ 3.0	$ 126.9	$ 7.9	$ 1.2	$ 6.7
Customer rights	113.5	65.0	48.5	117.4	56.6	60.8
Water rights	15.0	0.1	14.9	-	-	-
Lease rights	6.1	-	6.1	-	-	-
	$ 264.5	$ 68.1	$ 196.4	$ 125.3	$ 57.8	$ 67.5

8. Other assets:

		2005		2004
Cost				
Debenture issue expenses	$	18.7	$	11.4
Long-term receivables		25.2		8.2
Investments		11.8		9.0
Deferred charges		8.2		5.9
Regulatory asset		2.7		1.5
		66.6		36.0
Accumulated amortization				
Debenture issue expenses		4.6		3.4
Deferred charges		3.6		3.4
		8.2		6.8
	$	58.4	$	29.2

9. Short-term debt:

		2005		2004
Commercial paper	$	28.5	$	-

Bank lines of credit are unsecured, and are available to the Company up to an amount of $1,110.0 million. Of the total, $200.0 million is committed until August 2006, $50.0 million is committed under an extendable, term operating loan until August 2007, $300.0 million is committed under a two-year extendable term loan until December 2007, $300.0 million is committed under a three-year extendable term loan until December 2008, $210.0 million is committed under a five-year term loan until November 2009 and $50.0 million is uncommitted. At December 31, 2005, the Company had outstanding letters of credit issued under its credit facilities of $59.7 million under its $200.0 million credit facility (2004 – $nil), $66.5 million under its $300.0 million credit facility (2004 - $66.6 million), and $27.7 million under its $50.0 million uncommitted credit facility (2004 - $14.3 million) – see note 25. Amounts borrowed, and letters of credit issued, if any, under the two, three and five year term credit facilities are classified as long-term debt – see note 10.

Effective February 15, 2006, the one-year, two-year and three-year committed syndicated bank credit facilities were replaced by a single $800.0 million extendable syndicated bank credit facility consisting of a three-year $400.0 million facility and a five-year $400.0 million facility.

The Company's commercial paper program is authorized to $500.0 million and is backed by the committed bank lines.

10. Long-term debt:

	2005	2004
Obligation to The City of Edmonton (note 20):		
Due in 1-5 years at 10.92%[1] (2004 – 10.75%[1])	$ 150.0	$ 163.3
Due in 6-10 years at 9.58%[1] (2004 - 10.05%[1])	128.7	188.0
Due in 11-15 years at 8.75%[1] (2004 - 8.75%[1])	75.0	79.1
Due in 16-20 years at 7.01%[1] (2004 - 7.01%[1])	28.2	29.0
	381.9	459.4
Debentures, at 4.60%, due in 2005	-	79.0
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	-
Power LP unsecured senior notes, at 5.9%, due in 2014	224.5	-
Power LP secured term loan, at 11.3 %, due in 2010	5.7	-
Non-recourse financing:		
Brown Lake Project, at 8.7%, due in 2016	8.1	8.6
Joffre Cogeneration Project, at fixed and floating rates, due in 2020	73.4	79.9
Three year extendable credit facility, at floating rates	98.3	103.4
Power LP credit facility, at floating rates, due in 2009	209.1	-
	2,081.0	1,610.3
Less: current portion	54.0	131.0
	$ 2,027.0	$ 1,479.3

[1] Weighted average coupon rate

10. 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 per cent debentures, maturing in the year 2018 and totaling $75.0 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 and are 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 of $224.5 million (US$190.0 million) mature in July 2014 and bear interest at 5.9 per cent per annum, payable semi-annually. The senior notes are fully and unconditionally guaranteed by Power LP as to payment of principal, premium, if any, and interest on a senior unsecured basis.

Power LP secured term loan

The term loan is secured by a first fixed and specific mortgage over the Queen Charlotte plant. The loan bears interest at an annual rate of approximately 11.3 per cent and matures on July 15, 2010.

10. 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. $40.0 million of the debt bears a fixed interest rate of 8.59 per cent payable quarterly until September 2020. The remaining debt bears interest at the prevailing bankers' acceptance rate plus a spread of 1.50 (2004 - 1.50) per cent which escalates to 1.875 per cent over the term of the loan. In 2004, the Company entered into a 5.06 per cent fixed-for-floating interest rate swap on $7.6 million of the floating rate component of the debt. This interest rate swap expired on December 31, 2004. The debt is secured by a charge against project assets which have a carrying value of $117.8 million (2004 - $117.0 million). Brown Lake Project financing is secured by a charge against project assets which have a carrying value of $12.6 million (2004 - $12.9 million).

Two and three year extendable credit facility

Unsecured two and three year credit facilities of $300.0 million each, committed to December 2007 and December 2008 respectively, are available to the Company. At December 31, 2005, the Company had US$84.5 million (2004 – US$86.0 million) or CDN$98.3 million (2004 – CDN$103.4 million) outstanding under the three year extendable credit facility. Interest on this loan is floating and calculated at the current LIBOR rate plus 0.45 per cent. At December 31, 2005 the calculated rate was 4.50 per cent (2004 – 2.46 per cent).

As described in note 9, on February 15, 2006, the one-, two- and three-year credit facilities were replaced by an extendable syndicated bank credit facility consisting of a three-year $400 million facility and a five-year $400 million facility.

Power LP credit facility

The $210.0 million credit facility, presented net of $0.9 million of prepaid interest, is five-year, non-amortizing debt arranged through a credit facility with a syndicate of Canadian banks, whereby Power LP can obtain advances by way of prime loans, US Base Rate loans, LIBOR loans and Bankers' Acceptances. The outstanding principal is due in full upon maturity in November 2009 and bears interest at the average Bankers' Acceptances rate at December 31, 2005 of 3.8 per cent (the effective rate after consideration of interest rate swap contracts is 5.1 per cent).

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:

Year		Amount
2006	$	54.0
2007		47.5
2008		335.9
2009		241.2
2010		225.8

11. Other non-current liabilities:

		2005		2004
Asset retirement obligations (note 12)	$	79.9	$	59.5
Deferred incentives on generation units operating under PPAs (note 2(e))		23.5		30.9
Employee future benefit liabilities		15.5		10.6
Regulatory provision for plant decommissioning		7.0		6.9
Long-term incentive plan liability		4.6		4.6
Other		1.8		1.0
	$	132.3	$	113.5

Regulatory provision for plant decommissioning represents the liability for decommissioning the Company's rate-regulated distribution, transmission and water utility assets at the end of their useful lives, based on estimated removal costs, net of salvage value, as approved by the regulator. Upon the retirement of utility assets, the removal costs, net of salvage value, are charged to the provision for plant decommissioning.

12. 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:

		2005		2004
Balance, beginning of year	$	67.1	$	64.7
Assumption of Power LP obligations (note 3)		16.6		-
Liabilities incurred		8.2		6.6
Liabilities settled		(7.7)		(7.7)
Revision of previous estimates		-		0.7
Asset retirement accretion expense		3.3		2.9
Change in foreign exchange rates		-		(0.1)
		87.5		67.1
Less: current portion in accounts payable and accrued liabilities		7.6		7.6
	$	79.9	$	59.5

12. Asset retirement obligations, continued:

The Company estimates the undiscounted amount of cash flow required to settle its asset retirement obligations is approximately $316.3 million, calculated using inflation rates ranging from 2 to 3 per cent. The expected timing for settlement of the obligations is between 2006 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 2006 and 2010 for the Genesee coal mine. Discount rates ranging from 3.0 to 6.6 per cent were used to calculate the carrying value of the asset retirement obligations. No assets have been legally restricted for settlement of the liability.

13. Non-controlling interests:

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

		2005		2004
Non-controlling interests in Power LP	$	17.1	$	-
Preferred share dividends paid by subsidiary companies		21.5		21.5
	$	38.6	$	21.5

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

		2005		2004
Non-controlling interests in Power LP	$	541.5	$	-
Preferred shares issued by subsidiary companies		345.7		345.7
	$	887.2	$	345.7

The non-controlling interests in Power LP represents the approximately 69.4 per cent interest in EPCOR Power L.P. not owned by EPCOR.

During 2002 and 2001, respectively, 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 per cent and 90 per cent, 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.

14. 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 intercompany promissory notes between it and its subsidiaries described in note 13, 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.

15. Foreign currency translation adjustment:

An unrealized translation adjustment arose on the translation of foreign currency denominated assets and liabilities of the self-sustaining foreign operation. At the end of the first quarter of 2003, the exposure to the net investment in the self-sustaining foreign operation was hedged by borrowing funds denominated in the same foreign currency as the underlying asset.

The unrealized foreign exchange loss of $16.2 million at January 1, 2004 was due to the decrease in the U.S. dollar exchange rate prior to implementing the hedge.

At December 31, 2004, there was an unrealized foreign exchange loss of $7.8 million. The reduction of the cumulative translation loss during 2004 was due to the disposal of 49.85 per cent of the Company' net investment in its Frederickson plant as described in note 27.

Balance, January 1, 2004, representing net deferred foreign exchange losses	$	(16.2)
Unrealized loss on translation of the net investment in self-sustaining foreign operations		(0.8)
Unrealized gain on U.S. dollar debt as hedge of the net investment		2.2
Recognition of deferred foreign exchange losses on self-sustaining foreign operations due to sale of interest in Frederickson plant (note 27)		14.4
Recognition of deferred foreign exchange gains on repayment of U.S. dollar debt designated as a hedge of the net investment (note 27)		(7.4)
Balance, December 31, 2004, representing net deferred foreign exchange losses	$	(7.8)
Unrealized loss on translation of the net investment in self-sustaining foreign operations		(2.5)
Unrealized gain on U.S. dollar debt as hedge of the net investment		2.5
Balance, December 31, 2005	$	(7.8)

16. Change in non-cash operating working capital:

	2005	2004
Accounts receivable	$ (139.0)	$ 65.3
Income taxes recoverable	3.7	9.4
Inventories	(3.0)	(2.9)
Prepaid expenses	3.4	(0.6)
Accounts payable and accrued liabilities	115.5	0.5
Income taxes and amounts in lieu of income taxes payable	3.9	1.9
Other current liabilities	2.2	(0.1)
	$ (13.3)	$ 73.5

17. Financing expenses:

	2005	2004
Interest on long-term debt	$ 140.8	$ 143.7
Other interest income	(3.7)	(9.2)
	137.1	134.5
Amortization of debt issue costs	1.3	1.2
Capitalized interest	(6.8)	(25.1)
	$ 131.6	$ 110.6

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

	2005	2004
Interest paid on long-term debt	$ 141.6	$ 124.2
Other interest received	(3.7)	(9.5)
	$ 137.9	$ 114.7

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

	2005	2004
Income taxes	$ 37.8	$ 25.4
Amounts in lieu of income taxes	63.7	40.4
	$ 101.5	$ 65.8
Comprised of:		
Current income taxes and amounts in lieu of income taxes	46.0	62.9
Future income taxes and amounts in lieu of income taxes	55.5	2.9
	$ 101.5	$ 65.8

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:

	2005	2004
Income from continuing operations before income taxes and amounts in lieu of income taxes	$ 298.8	$ 270.0
Statutory income tax rates	33.62%	33.87%
Income taxes and amounts in lieu of income taxes at statutory rates	100.5	91.4
Increase (decrease) resulting from:		
Income exempt from income taxes at statutory rate	(42.8)	(35.6)
Adjustment of amounts in lieu of income taxes on settlement	38.1	-
Large Corporations Tax	3.9	3.5
Income tax related to prior periods	1.9	0.6
Non-deductible amounts	(0.6)	9.0
Adjustment to future income tax assets and liabilities for enacted changes in income tax laws and rates	-	(1.3)
Other	0.5	(1.8)
	$ 101.5	$ 65.8

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

Income taxes and amounts in lieu of income taxes paid in 2005 were $43.6 million (2004 - $62.6 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:

	2005	2004
Future income tax asset:		
Cumulative eligible capital	$ 53.7	$ 83.7
Property, plant and equipment – differences in net book value and undepreciated capital cost	24.3	5.9
Construction in progress	25.5	0.4
Incentive income from generation units operating under PPAs – deferred for accounting purposes	11.1	15.2
Non-capital losses carried forward	40.6	53.8
Asset retirement obligations	31.3	27.8
Derivative financial instruments	35.2	7.4
Power purchase arrangements	-	9.8
Long-term debt	2.1	-
Preferred share issue costs	1.5	1.1
Customer rights	-	1.5
Other	5.4	2.6
	230.7	209.2
Future income tax liability:		
Deferred income from partnership	29.3	30.3
Property, plant and equipment – differences in net book value and undepreciated capital cost	111.7	14.5
Power purchase arrangements	47.1	-
Contract rights and other intangible assets	24.0	-
Asset retirement obligation assets	9.9	9.9
Derivative financial instruments	34.3	4.9
Other assets	1.4	3.2
Deferred amounts receivable	-	1.0
	257.7	63.8
Net future tax (liability) asset	$ (27.0)	$ 145.4

	2005	2004
Presented in the balance sheet as follows:		
Current assets	$ 2.6	$ 0.8
Non-current assets	87.7	175.3
Current liabilities	(18.7)	(30.3)
Non-current liabilities	(98.6)	(0.4)
	$ (27.0)	$ 145.4

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

As noted in note 2(g), effective January 1, 2001 the Company became subject to the Payment in Lieu of Tax Regulation (PILOT regulation) in Alberta requiring it to pay amounts in lieu of income taxes on certain of its operations. Under the PILOT regulation, there was a deemed disposition and reacquisition, at fair value, of the applicable assets subject to the regulation. At January 1, 2001, the Company estimated the balance of future amounts in lieu of income tax assets associated with goodwill to be $112.9 million, based on an estimated fair market value of goodwill of $400 million.

In July 2003, Alberta Revenue notified the Company that it was their view that the value of goodwill as determined by the Company for purposes of PILOT was overstated at the date the Company first became subject to the PILOT Regulation. 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 Regulation. The value of goodwill was settled at $250 million. As a result of the settlement upon the value of goodwill with Alberta Revenue, the Company reduced its future income tax asset associated with goodwill by $28.3 million and recognized $9.8 million of current income taxes. These adjustments resulted in a charge to income taxes and amounts in lieu of income taxes expense of $38.1 million in 2005. Interest of $1.7 million related to this settlement was reflected in financing expenses. The Company has paid Alberta Revenue the $11.5 million of current taxes and interest related to these adjustments.

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, 2005 and 2004:

			2005			2004
	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	10.9	1 to 5	$ (130.0)	12.0	1 to 5	$ 12.2
Electricity purchases	3.6	1 to 5	35.5	8.2	1 to 2	13.4

19. Financial instruments, continued:

Fair value of off-balance sheet forward exchange contracts

The Company had no off-balance sheet forward exchange contracts at December 31, 2005. At December 31, 2004 the Company had $28.5 million (17.3 million Euros) of off-balance sheet forward exchange contracts with a fair value of negative $0.2 million. The fair value of the Company's forward foreign exchange contracts is determined by applying the applicable period end forward foreign exchange rate to the foreign currency-denominated contract value.

Derivative financial instruments not qualifying for hedge accounting

Derivative financial instruments assets and liabilities on the consolidated balance sheets represent both deferred unrealized gains and losses on derivative financial instruments recorded upon termination of a hedging relationship, and unrealized gains and losses on derivative financial instruments which did not satisfy the conditions for hedge accounting as described in note 2(f). Such deferred gains and losses are recognized in income when the hedged item settles.

Included in non-current derivative financial instruments assets is $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. These unrealized losses are recognized in income over 6 years, being the remaining term of the respective financial instruments upon application of the guideline.

On the Company's acquisition of Power LP, $4.4 million of the purchase price was allocated to forward foreign exchange contracts and ($3.2) million was allocated to interest rate swap contracts (note 3). The carrying value at December 31, 2005 related to these contracts is included in non-current derivative financial instruments asset and non-current derivative financial instruments liability, respectively, on the consolidated balance sheets.

19. Financial instruments, continued:

Fair value of other financial assets (liabilities)

	2005	2004
Long-term debt	$ (2,371.0)	$ (1,922.7)

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, 2005 and 2004. 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 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 according to a pre-agreed basis. For other retail customers which represent a diversified customer base, credit losses are generally low across the sector and the Company provides for an allowance for doubtful accounts to absorb credit losses. The allowance for doubtful accounts is $6.1 million (2004 - $11.0 million).

The Company also has credit exposures to large suppliers of electricity and natural gas. The Company mitigates this exposure 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 maturing in the year. At December 31, 2005 approximately 92 per cent (2004 - 91 per cent) of the Company's debt was at fixed rates.

20. Related party balances and transactions:

The following summarizes the Company's related party balances and transactions with The City of Edmonton. All transactions are in the normal course of operations, and are recorded at the exchange value generally based on normal commercial rates, or as agreed to by the parties.

		2005	2004
Balance sheet:			
Accounts receivable	(a)	$ 29.9	$ 27.2
Property, plant and equipment	(b)	2.6	4.3
Long-term debt – see note 10		381.9	459.4
Income Statement:			
Revenues: - energy and water sales		$ 18.8	$ 22.6
- other	(c)	46.9	46.1
Operations, maintenance and administration	(d)	6.5	9.5
Franchise fee, property taxes and other taxes	(e)	44.6	42.9
Financing expenses	(f)	62.8	73.5

(a) The accounts receivable balance due from The City of Edmonton at the end of the year includes $26.9 million (2004 - $21.5 million) in respect of the negotiated sharing of the earnings of The City of Edmonton Sinking Fund. During the year, the Company received $ nil (2004 - $ nil) of these balances.

(b) Costs of capital construction for water distribution mains and infrastructure programs of $2.6 million (2004 - $2.7 million), and cost of vehicles purchased from The City of Edmonton of $ nil (2004 - $1.6 million).

(c) Revenues from the provision of maintenance, repair and construction services of $39.6 million (2004 - $39.5 million) and $7.3 million for customer billing services (2004 - $6.6 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 $34.6 million (2004 - $33.7 million) at 0.412 cents per kilowatt-hour (2004 - 0.399 cents per kilowatt hour) for EPCOR Distribution Inc. and at 7.6 per cent of qualifying revenues of EPCOR Water Services Inc. (2004 - 7.2 per cent for the first three months of 2004 and 7.6 per cent for the remaining 9 months). Property taxes of $10.0 million (2004 - $9.2 million) on property owned within The City of Edmonton municipal boundaries.

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

21. Joint ventures:

A financial summary of the Company's investments in joint ventures as at December 31, 2005 and 2004 on a proportionately consolidated basis, is as follows:

	2005	2004
Current assets	$ 36.1	$ 24.0
Long-term assets	592.5	573.4
Current liabilities	18.0	19.1
Long-term liabilities	68.9	80.8
Revenues[1]	71.0	57.7
Expenses[2]	85.2	46.7
Net income	(14.2)	11.0
Cash flows from operating activities	(42.0)	23.2
Cash flows from (used in) investing activities	(27.2)	143.3
Cash flows (used in) from financing activities	71.7	(162.3)

[1]Excludes all revenues from the Genesee Phase 3 Project, 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.

22. Employee future benefits:

Multiemployer defined benefit pension plan and defined contribution pension plan

Ninety four per cent of the Company's employees are either members of the Local Authority Pension Plan (LAPP) 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.

Defined benefit plans

The effective dates for the latest actuarial valuations of the Company's registered and supplemental pension plans were December 31, 2002 and December 31, 2003, respectively. The effective dates of the next required valuation for funding purposes are no later than December 31, 2005 and December 31, 2006, respectively. The date used to measure the plan assets and the accrued benefit obligation was December 31, 2005. The measurement was obtained by extrapolating the results from the previous actuarial valuations to the measurement date. The supplemental pension plan is solely the obligation of the Company. The Company is not obligated to fund the supplemental pension plan but is obligated to pay benefits under the terms of the plan as they come due. The supplemental pension plan is unfunded at December 31, 2005.

22. Employee future benefits, continued:

Defined benefit plans, continued

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, 2005, 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

	2005	2004
Costs recognized for the years ended December 31:		
Service cost	$ 1.0	$ 1.1
Interest on benefit obligation	0.4	-
Actual return on assets	(0.1)	-
Actuarial losses in 2005	1.4	0.9
Difference between actuarial (gain) loss recognized and actual (gain) loss on accrued benefit obligation in 2005	(0.4)	-
Defined benefit plans cost	2.3	2.0
Defined contribution plans cost	12.5	9.6
Net expense	$ 14.8	$ 11.6

	2005	2004
Funded status as at December 31:		
Market value of plan assets	$ 5.9	$ -
Accrued benefit obligation	14.5	4.3
Funded status – plan deficit	(8.6)	(4.3)
Amounts not yet recognized in financial statements:		
Unamortized net (gains) losses	-	-
Accrued benefit liability recognized in financial statements	$ (8.6)	$ (4.3)
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.

22. Employee future benefits, continued:

Plan benefit costs, assets and obligations, continued

	2005	2004
Reconciliation of accrued benefit obligation:		
Accrued benefit obligation as at January 1	$ 4.3	$ 2.3
Estimated obligation on transfer of employees relating to Power LP acquisition	7.8	-
Past service cost adjustment	(0.4)	-
Service cost	1.0	1.1
Interest cost	0.4	-
Actual benefits paid	-	-
Actuarial loss	1.4	0.9
Accrued benefit obligation as at December 31	$ 14.5	$ 4.3

	2005	2004
Plan assets:		
Market value of assets at January 1	$ -	$ -
Estimated assets on transfer of employees relating to Power LP acquisition	5.8	-
Benefits paid	-	-
Actual return of plan assets (net of expenses)	0.1	-
Market value of assets as at December 31	$ 5.9	$ -

Assumptions:

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

	2005	2004
Accrued benefit obligation at December 31		
Discount Rate	5.0%	6.0%
Rate of compensation increase	4.0%	3.5%
Benefit Cost for year ended December 31		
Discount Rate	5.0%	6.0%
Rate of compensation increase	4.0%	3.5%
Expected rate of return on plan assets	7.0%	Not applicable

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, 2005.

23. Plants under operating leases:

Included in the acquired assets of Power LP are certain power generation plants which operate under power purchase agreements 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 and Williams Lake plants, are accounted for as assets under operating leases. As at December 31, 2005, the carrying value of such property, plant and equipment was $394.8 million, less accumulated depreciation of $6.6 million. The Company's revenue pursuant to the arrangements for the four month period ended December 31, 2005 was $29.6 million.

24. Contingencies and commitments:

(a) The Company has committed to the Ontario government to construct a wind-powered generation facility in Ontario at an estimated cost of $300 million over the next three years. The Company is currently negotiating contracts with suppliers in relation to this capital project. There are no other significant contractual obligations or commitments to major capital projects outside of normal business operations at December 31, 2005 (2004 - $33.8 million).

(b) Minimum operating lease payments for premises are approximately:

2006	$	2.2
2007		1.9
2008		2.1
2009		2.0
2010		1.8
Thereafter		1.5

(c) In 2005, 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 2006 is $225.0 million. The actual amounts for 2006 and future years may vary from estimates depending on generation volume and scheduled outages. It is expected that the annual payments over the terms of the Alberta PPAs, as described in note 2(k), will range from $196 million to $250 million, adjusted for inflation, other than in the event of a forced outage.

(d) At December 31, 2005, the Company has committed to provide future funding of US$4.8 million to Nth Power Technologies Fund II-A, L.P., a venture capital investment fund in which the Company holds a portfolio investment with a carrying value of CDN $5.7 million at December 31, 2005.

24. Contingencies and commitments, continued:

(e) The Company and approximately 450 other employers, participating in certain Alberta public pension plans including the Local Authorities Pension Plan, have been named in a $1.25 billion class action lawsuit regarding pension benefits. The Company's opinion is that this lawsuit is without merit. The final outcome is not determinable at this time and, accordingly, no amount has been accrued in the financial statements.

(f) 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 the commodity charge for gas under such agreements. NAL and Devon additionally seek monetary damages based on referenced spot gas prices should the courts uphold their claims. Power LP has filed statements of defense and will vigorously defend the actions. The final outcome is not determinable at this time and, accordingly, no amount has been accrued in the financial statements.

(g) 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.

(h) As disclosed in note 2(c), settlement processes in the Alberta electricity market may result in adjustments to previously settled loads in future periods. The adjustments will result in changes to previous estimates of electricity revenues and expenses. Any such adjustments, which could be material, will be recorded in the period they become known.

25. Guarantees:

The Company has issued letters of credit for $153.9 million (2004 - $80.9 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 $30.0 million related to prudential support provided by the Company on behalf of the purchaser of certain competitive mass-market contracts in 2004 - see note 27. The prudential support will be provided until 2009, unless conditions for early termination are met. The prudential support is required by AESO and by Alberta gas and electricity distribution service providers in order for the purchaser to participate in the Alberta Power Pool and retail energy market. The Company's maximum exposure, based on December 31, 2005 electricity and gas prices and based on maximum volumes under the energy supply agreements, is estimated at approximately $40.0 million (2004 - $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, 2005, $2.1 million (2004 - $12.8 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, 2005.

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, 2005.

26. Segment disclosures:

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

Generation

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

Distribution and Transmission

Distribution and Transmission is involved in the transmission and distribution of electricity within The City of Edmonton. This segment also provides complementary commercial services including streetlighting and transportation support services.

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.

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, 2005

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 527.5	$ 115.9	$ 1,880.1	$ 174.7	$ 0.6	$ -	$ 2,698.8
Intersegment revenues	109.9	131.8	26.4	0.2	-	(268.3)	-
Total revenues	637.4	247.7	1,906.5	174.9	0.6	(268.3)	2,698.8
Depreciation, amortization, and asset retirement accretion	92.6	25.7	39.4	14.0	11.8		183.5
Other operating expenses	329.1	182.3	1,736.6	121.0	(15.9)	(268.2)	2,084.9
Financing expenses	146.2	21.4	48.1	21.1	(105.2)		131.6
Income taxes and amounts in lieu of income taxes	66.7	-	24.1	(0.5)	11.2		101.5
Total expenses	634.6	229.4	1,848.2	155.6	(98.1)	(268.2)	2,501.5
Income from continuing operations before non-controlling interests	2.8	18.3	58.3	19.3	98.7	(0.1)	197.3
Non-controlling interests	17.1	-	-	-	21.5		38.6
Net income (loss) from continuing operations	(14.3)	18.3	58.3	19.3	77.2	(0.1)	158.7
Discontinued operations (note 28)	28.4	-	-	-	-	-	28.4
Net income	14.1	18.3	58.3	19.3	77.2	(0.1)	187.1
Total assets	3,715.1	559.7	783.4	519.2	92.3	(10.9)	5,658.8
Capital additions	118.2	64.5	7.9	47.5	5.8	-	243.9

26. Segment disclosures, continued:

Year ended December 31, 2004

	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	$ 428.7	$ 86.3	$ 1,942.2	$ 136.9	$ 0.5	$ -	$ 2,594.6
Intersegment revenues	39.0	145.3	24.1	0.2	-	(208.6)	-
Total revenues	467.7	231.6	1,966.3	137.1	0.5	(208.6)	2,594.6
Depreciation, amortization, and asset retirement accretion	60.3	23.6	42.7	13.0	12.4	-	152.0
Other operating expenses	220.7	165.5	1,817.0	80.7	(13.3)	(208.6)	2,062.0
Financing expenses	117.7	19.4	50.0	19.1	(96.7)	1.1	110.6
Income taxes and amounts in lieu of income taxes	33.5	-	20.6	-	11.7	-	65.8
Total expenses	432.2	208.5	1,930.3	112.8	(85.9)	(207.5)	2,390.4
Income from continuing operations before non-controlling interests	35.5	23.1	36.0	24.3	86.4	(1.1)	204.2
Non-controlling interests	-	-	-	-	21.5	-	21.5
Net income from continuing operations	35.5	23.1	36.0	24.3	64.9	(1.1)	182.7
Discontinued operations (note 28)	17.9	-	(0.6)	-	(2.0)	-	15.3
Net income (loss)	53.4	23.1	35.4	24.3	62.9	(1.1)	198.0
Total assets	2,041.5	514.8	700.5	452.8	502.9	(10.5)	4,202.0
Capital additions	102.3	47.6	14.6	46.7	10.3	(1.1)	220.4

26. Segment disclosures, continued:

Geographic information:

	2005				2004			
	Canada	U.S.	Intersegment Eliminations	Total	Canada	U.S.	Intersegment Eliminations	Total
Revenues - external	$ 2,565.9	$ 132.9	$ -	$ 2,698.8	$ 2,499.6	$ 95.0	$ -	$ 2,594.6
Intersegment revenues	20.2	28.8	(49.0)	-	22.6	12.3	(34.9)	-
Total revenues	$ 2,586.1	$ 161.7	$ (49.0)	$ 2,698.8	$ 2,522.2	$ 107.3	$ (34.9)	$ 2,594.6
Capital assets	$ 3,359.9	$ 338.4	$ -	$ 3,698.3	$ 2,642.4	$ 102.3	$ -	$ 2,744.7

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. Business acquisitions and disposals:

Acquisitions and disposals during 2005

During 2005, the Company disposed 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. The gain on sale is included in the Company's revenues.

In addition, the Company acquired two small businesses: an Ontario-based wind power company and a water utility company in British Columbia. The net assets acquired, which were not material, were mainly comprised of property, plant and equipment and contract rights, and the excess of the purchase prices over the fair values of the acquired net assets resulted in goodwill of $2.8 million.

The net cash outflow to the Company of these 2005 acquisitions and disposals was $0.1 million.

27. Disposals, continued:

Sale of competitive mass-market energy contracts during 2004

Effective November 1, 2004, the Company sold the majority of its Alberta competitive mass-market electricity and natural gas contracts (the contracts) to Alberta Energy Savings L.P. (AES), a subsidiary of Ontario Energy Savings Corporation. Net proceeds of $10.4 million, after related selling costs, resulted in a gain of $7.7 million before income taxes of $1.8 million. The gain is included in the Company's revenues.

The Company entered into a five year agreement with AES effective December 1, 2004 to continue to provide customer call centre, billing, and revenue management services to mass-market contract holders as an agent of AES. AES may elect to terminate the agreement after two years with payment of a termination fee. Additional amounts are payable or receivable by the Company depending on defined service levels and the level of customer growth achieved by AES.

The Company also entered into energy supply agreements whereby AES will obtain from the Company, over a five year term, wholesale natural gas supply as well as a fixed price swap for electricity exchanged by AES through the Power Pool. The Company has agreed to not compete in the competitive mass-market retail energy business in Alberta for a period of two years from the effective date of the sale.

Sale of interest in Frederickson plant during 2004

On April 29, 2004, the Company finalized the sale of a 49.85 per cent interest in its Frederickson generation plant (the plant), an asset of the Company's Generation segment, to Puget Sound Energy, Inc. Proceeds from the sale were $104.9 million resulting in a loss of $12.4 million before income taxes, including foreign exchange losses of $7.0 million. The loss is included in operations, maintenance and administration expenses. The cash proceeds from the sale were used to repay the short-term portion of U.S. dollar denominated debt which had been designated as a hedge against the Company's net investment in the plant's self-sustaining foreign operations. The Company's remaining interest in the plant is accounted for in accordance with note 2(q).

28. Discontinued operations:

Clover Bar generation plant

On April 1, 2005, Alberta's Balancing Pool (the Balancing Pool), as the power purchase arrangement (PPA) holder, advised the Company of its decision to terminate the Clover Bar PPA, effective close of business on September 30, 2005. The Company studied a variety of alternatives to redeploy the natural gas-fired Clover Bar generation plant (the Clover Bar plant), and has chosen to decommission the existing generation units effective close of business on September 30, 2005.

In accordance with the terms of the PPA, EPCOR received a termination payment from the Balancing Pool on September 30, 2005 of $82.7 million. As a result of the decision to decommission the Clover Bar plant, the net book value of the related assets, including asset retirement obligation assets, was written down by $62.5 million. The net gain of $20.2 million before income taxes has been reflected in the results of discontinued operations in the consolidated statements of income. The Company anticipates additional reimbursements from the Balancing Pool as decommissioning is performed. Asset retirement expenditures are expected to be incurred over the next two years. The estimated asset retirement obligations have been reflected in the financial statements as at December 31, 2005.

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.

		2005		2004
Current assets of discontinued operations				
Accounts receivable, net	$	0.3	$	4.9
Inventories and prepaid expenses		0.2		5.6
	$	0.5	$	10.5
Non-current assets of discontinued operations				
Property, plant and equipment	$	3.1	$	64.7
Current liabilities of discontinued operations				
Accounts payable and accrued liabilities	$	5.0	$	1.7
Non-current liabilities of discontinued operations				
Asset retirement obligations and other	$	15.6	$	26.3

28. Discontinued operations, continued:

Clover Bar generation plant, continued:

Operating results from the discontinued Clover Bar plant for the years ended December 31, 2005 and 2004, including an allocation of interest expense and income taxes directly attributable to the discontinued operations, are as follows:

	2005	2004
Revenues	$ 51.0	$ 59.8
Operating expenses	23.2	30.1
Operating income	27.8	29.7
Financing expenses	-	0.2
PPA termination payment	(82.7)	-
Write-down of property, plant and equipment and other assets	62.5	-
Net income from discontinued operations before income taxes	48.0	29.5
Income taxes	19.6	11.6
Net income from discontinued operations	$ 28.4	$ 17.9

The discontinued Clover Bar plant operations are included in the Generation segment.

Water heater rental business

On December 18, 2003, the Company sold its water heater rental business to the UE Waterheater Income Fund (the Fund) through an initial public offering of fund units. Proceeds from the sale included cash and $51.3 million in units of the Fund. On January 9, 2004, the Company sold its units in the Fund for $51.3 million in cash.

On April 1, 2004, a small heating, ventilation, and air conditioning equipment (HVAC) business was sold by the Company with no significant gain or loss resulting from the sale. The results of operations of the HVAC business for the year ended December 31, 2004 of $0.6 million and additional underwriting, offering costs and post-closing adjustments on the 2003 sale of the water heater rental business of $2.0 million have been reported as a net loss from discontinued operations of $2.6 million in the consolidated statements of income.

The discontinued HVAC operations are included in the Energy Services segment..

29. Subsequent event:

On January 3, 2006, the Company announced that it 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 regulation - see note 2(g). As a result of the restructuring, EGI no longer met the criteria for exemption from tax under section 149 of the Income Tax Act ("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 tax effect of these additional deductions will be recognized as future income tax assets on EPCOR's consolidated balance sheet resulting in a corresponding increase in consolidated net income estimated to be approximately $115 million, to be recorded in the first quarter of 2006. The resulting future income tax assets will be reduced over time, as the underlying income tax deductions are utilized to reduce taxable income.

30. Comparative figures:

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