



CANADIAN UTILITIES LIMITED
An **ATCO** Company

CONSOLIDATED FINANCIAL STATEMENTS

**FOR THE YEAR ENDED
DECEMBER 31, 2006**

February 21, 2007

Auditors' Report

To the Share Owners of Canadian Utilities Limited

We have audited the consolidated balance sheets of **Canadian Utilities Limited** as at December 31, 2006 and 2005 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation'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 the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS
(Millions of Canadian Dollars except per share data)

	Note	Three Months Ended December 31		Year Ended December 31	
		2006	2005	2006	2005
<i>(Unaudited)</i>					
Revenues		\$ 671.1	\$ 680.3	\$2,430.4	\$2,515.8
Costs and expenses					
Natural gas supply		10.2	18.3	36.4	162.2
Purchased power		12.5	12.2	46.1	45.4
Operation and maintenance		243.5	261.7	950.3	1,003.6
Selling and administrative		74.9	57.3	207.5	190.4
Depreciation and amortization		95.6	84.5	348.5	311.5
Interest	7, 12	54.6	51.4	222.9	210.0
Franchise fees		42.4	49.5	150.4	152.3
		533.7	534.9	1,962.1	2,075.4
Interest and other income	6	137.4	145.4	468.3	440.4
Earnings before income taxes		18.9	10.6	58.5	36.6
Income taxes	7	156.3	156.0	526.8	477.0
		47.4	58.0	167.1	175.6
Dividends on equity preferred shares		108.9	98.0	359.7	301.4
		8.9	8.9	35.8	35.8
Earnings attributable to Class A and Class B shares		100.0	89.1	323.9	265.6
Retained earnings at beginning of period		1,741.1	1,670.4	1,721.9	1,603.4
		1,841.1	1,759.5	2,045.8	1,869.0
Dividends on Class A and Class B shares		36.3	34.9	176.7	139.6
Purchase of Class A shares and other direct charges to retained earnings	8	0.4	2.7	64.7	7.5
Retained earnings at end of period		\$1,804.4	\$1,721.9	\$1,804.4	\$1,721.9
Earnings per Class A and Class B share	15	\$ 0.80	\$ 0.70	\$ 2.57	\$ 2.09
Diluted earnings per Class A and Class B share	15	\$ 0.80	\$ 0.69	\$ 2.56	\$ 2.08
Dividends paid per Class A and Class B share	15	\$ 0.29	\$ 0.275	\$ 1.40	\$ 1.10

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET
(Millions of Canadian Dollars)

		December 31	
	Note	2006	2005
ASSETS			
Current assets			
Cash and short term investments	18	\$ 798.8	\$ 824.6
Accounts receivable		362.3	353.4
Inventories		96.5	88.0
Regulatory assets	2	13.3	19.1
Prepaid expenses		23.6	19.9
		1,294.5	1,305.0
Property, plant and equipment	9	5,426.1	5,208.7
Regulatory assets	2	43.2	35.0
Other assets	10	229.7	269.1
		\$6,993.5	\$6,817.8
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness		\$ -	\$ 0.2
Accounts payable and accrued liabilities		338.8	342.6
Income taxes payable		22.7	26.7
Future income taxes	7	0.3	4.1
Regulatory liabilities	2	0.5	6.4
Non-recourse long term debt due within one year	12	59.3	57.0
		421.6	437.0
Future income taxes	7	194.7	200.3
Regulatory liabilities	2	148.8	161.9
Deferred credits	13	229.0	253.8
Long term debt	12	2,411.5	2,231.0
Non-recourse long term debt	12	626.7	673.8
Equity preferred shares	14	636.5	636.5
Class A and Class B share owners' equity			
Class A and Class B shares	15	516.0	519.1
Contributed surplus	16	1.2	0.7
Retained earnings		1,804.4	1,721.9
Foreign currency translation adjustment		3.1	(18.2)
		2,324.7	2,223.5
		\$6,993.5	\$6,817.8

[Original signed by N.C. Southern]

DIRECTOR

[Original signed by B.K. French]

DIRECTOR

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOWS
(Millions of Canadian Dollars)

	Note	Three Months Ended		Year Ended	
		December 31		December 31	
		2006	2005	2006	2005
<i>(Unaudited)</i>					
Operating activities					
Earnings attributable to Class A and Class B shares		\$ 100.0	\$ 89.1	\$ 323.9	\$ 265.6
Adjustments for:					
Depreciation and amortization		95.6	84.5	348.5	311.5
Future income taxes		11.3	0.6	(1.6)	7.7
Deferred availability incentives		(41.0)	14.5	(20.2)	13.7
TXU Europe settlement - net of income taxes	5	(3.3)	(3.7)	(1.6)	45.8
Other		5.8	2.8	8.5	15.0
Funds generated by operations		168.4	187.8	657.5	659.3
Changes in non-cash working capital	17	(48.5)	(1.2)	(39.6)	90.2
Cash flow from operations		119.9	186.6	617.9	749.5
Investing activities					
Purchase of property, plant and equipment		(184.0)	(181.2)	(567.7)	(526.7)
Proceeds on transfer of retail energy supply businesses					
- net of income taxes	3	-	-	-	43.4
Costs on disposal of property, plant and equipment		(4.3)	(4.4)	(10.4)	(5.9)
Contributions by utility customers for extensions to plant		20.1	6.7	81.3	44.1
Non-current deferred electricity costs		(8.7)	(5.7)	4.5	(15.7)
Changes in non-cash working capital	17	15.4	24.4	(18.3)	(3.4)
Income tax reassessment	7	-	-	(12.8)	-
Other		0.9	(0.1)	(4.1)	(6.2)
		(160.6)	(160.3)	(527.5)	(470.4)
Financing activities					
Issue of long term debt		320.0	185.0	355.5	222.0
Repayment of long term debt		(175.0)	(35.4)	(175.0)	(167.1)
Repayment of non-recourse long term debt		(12.6)	(9.1)	(64.6)	(54.3)
Net issue (purchase) of Class A shares		1.9	(2.7)	(67.5)	(2.7)
Dividends paid to Class A and Class B share owners		(36.3)	(34.9)	(176.7)	(139.6)
Changes in non-cash working capital	17	(0.1)	0.3	(0.1)	3.1
Other		(2.6)	(2.1)	(3.9)	(3.2)
		95.3	101.1	(132.3)	(141.8)
Foreign currency translation		11.6	0.2	16.3	(11.2)
Cash position ⁽¹⁾					
Increase (decrease)		66.2	127.6	(25.6)	126.1
Beginning of period		732.6	696.8	824.4	698.3
End of period		\$ 798.8	\$ 824.4	\$ 798.8	\$ 824.4

⁽¹⁾ Cash position consists of cash and short term investments less current bank indebtedness.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2006

(tabular amounts in millions of Canadian dollars)

1. Summary of significant accounting policies

Financial Statement Presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments (the “Corporation”). Principal operations are Utilities (ATCO Electric, ATCO Gas, ATCO Pipelines), Power Generation (ATCO Power, Alberta Power (2000)) and Global Enterprises (ATCO Midstream, ATCO Frontec, ATCO I-Tek). Significant joint venture investments consist principally of power generation plants; a substantial portion of Power Generation’s operations are conducted through joint ventures.

Certain comparative figures have been reclassified to conform to the current presentation.

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited’s wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the “regulated operations”. Accounting for rate regulated operations is described in Note 2.

Use of Estimates

The preparation of the Corporation’s consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. On an on-going basis, management reviews its estimates, particularly those related to depreciation and amortization methods, useful lives and impairment of long-lived assets, amortization of deferred availability incentives, asset retirement obligations and employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

Revenue Recognition

For regulated operations, revenues are recognized in a manner that is consistent with the underlying rate design as mandated by the regulator.

Revenues from ATCO Gas’ regulated distribution of natural gas include variable charges, which are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues from the sale of natural gas by ATCO Gas from storage, which ended on March 31, 2005, were recognized upon delivery.

Revenues from ATCO Electric’s regulated distribution of electricity include variable charges, which are recognized on the basis of meter readings upon delivery of electricity to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period. Revenues for the use of ATCO Electric’s regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from ATCO Pipelines’ regulated transportation of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

1. Summary of significant accounting policies (continued)

Revenues from regulated sales and distribution of natural gas and electricity by other regulated operations, excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of usage not yet billed.

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. Incentives and penalties associated with Power Purchase Arrangements (“PPA”) are recognized as described under the accounting policy for deferred availability incentives.

Revenues from ATCO Midstream’s natural gas storage and processing capacity are recognized on the basis of contractual arrangements, and revenues from the sale of natural gas liquids are recognized upon delivery.

Revenues from the supply of contracted services are recorded by the percentage of completion method; full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided.

Natural Gas Supply

Natural gas supply expense for regulated operations, which consists of natural gas volumes purchased for sales to customers (see Note 3 regarding natural gas supply of regulated operations following the transfer of retail energy supply businesses by ATCO Gas and ATCO Electric in 2004), is based on actual costs incurred.

Natural gas supply expense for other subsidiaries, which consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties, is based on actual costs incurred.

Purchased Power

Purchased power expense in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.

Income Taxes

The regulated operations follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of their rates. When future income taxes are not provided in the income tax component of current rates, such future income taxes are not recognized to the extent that it is expected that they will be recovered from customers through inclusion in future rates.

Other subsidiaries follow the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Inventories

Inventories are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions by utility customers for extensions to plant.

1. Summary of significant accounting policies (continued)

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the Alberta Energy and Utilities Board (“AEUB”) for debt and equity capital. Property, plant and equipment in the other subsidiaries include capitalized interest incurred during construction.

Certain regulated additions are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers’ specific requirements. These contributions are amortized on the same basis as, and offset the depreciation charge of, the assets to which they relate.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets, excluding Alberta Power (2000)’s generating plants, are approved by the AEUB and include a provision for future removal costs and site restoration costs (see the accounting policy for asset retirement obligations below). On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset’s carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset’s carrying value and its fair value, which is determined using present value techniques.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt, issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue and issue costs of preferred shares relating to other subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption.

Deferred Availability Incentives

Under the terms of the PPA’s, the Corporation is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to the Corporation by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Corporation to the PPA counterparties when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPA’s, should accumulated incentives plus estimated future incentives exceed accumulated penalties plus estimated future penalties, the excess will be amortized to revenues on a straight-line basis over the remaining term of the PPA’s. Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

Asset Retirement Obligations

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques.

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

1. Summary of significant accounting policies (continued)

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets are not recognized as the Corporation expects to use the assets in service for an indefinite period. As such, no final removal date can be determined and, consequently, a reasonable estimate of the related retirement obligations cannot be made at this time. Asset retirement obligations have been recorded for the regulated generating plants of Alberta Power (2000) and other generating plants and natural gas liquids extraction and processing plants.

Effective January 1, 2006, the Corporation retroactively adopted the Canadian Institute of Chartered Accountant's ("CICA") Emerging Issues Abstract regarding conditional asset retirement obligations. This abstract requires an entity to record a liability for an asset retirement obligation where the timing and/or method of settlement are conditional upon the occurrence of a future event that may or may not be within the control of the entity. Adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

Long Term Debt Due Within One Year

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Hedging

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

The Corporation designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. The Corporation also assesses, both at the hedge's inception and on an ongoing basis, whether the derivative instruments that are used in hedging transactions are effective in offsetting changes in fair values or cash flows of the hedged items.

Payments or receipts on derivative instruments that are designated and effective as hedges are recognized concurrently with, and in the same financial category as, the hedged item.

If a derivative instrument is terminated or ceases to be effective as a hedge prior to maturity, the gain or loss at that date is deferred and recognized in income concurrently with the hedged item. Subsequent changes in the value of the derivative instrument are reflected in income. If the designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, the gain or loss at that date on such derivative instrument is recognized in income.

Employee Future Benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

1. Summary of significant accounting policies (continued)

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

Pursuant to an AEUB decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred in non-current regulatory assets and liabilities.

Employer contributions to the defined contribution pension plans are expensed as paid.

Stock Based Compensation Plans

The Corporation expenses stock options granted on and after January 1, 2002; no compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by GAAP. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

No compensation expense is recognized when share appreciation rights are granted. Prior to vesting, compensation expense arising from an increase or decrease in the market price of the shares over the base value of the rights is accrued equally over the remaining months to the date of vesting. After that date, compensation expense arising from an increase or decrease in the market price of the shares is recognized monthly in earnings.

Effective January 1, 2006, the Corporation retroactively adopted the CICA Emerging Issues Abstract regarding stock based compensation for employees eligible to retire before the vesting date. This abstract requires an entity to recognize the compensation cost attributable to such an award over the period from grant date to the date the employee becomes eligible to retire. Since the Corporation does not have stock based compensation plans that contain such provisions, adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in the foreign currency translation adjustment in share owners' equity.

Monetary assets and liabilities of integrated foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date, non-monetary assets and liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred, and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of integrated foreign operations are recognized in earnings.

Transactions undertaken by Canadian operations that are denominated in foreign currencies are translated into Canadian dollars at the rate of exchange in effect at the transaction date.

2. Accounting for rate regulated operations

Nature and economic effects of rate regulation

ATCO Electric, ATCO Gas and ATCO Pipelines (the “utilities”) are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area.

The generating plants of Alberta Power (2000) were regulated by the AEUB until December 31, 2000 but are now governed by legislatively mandated PPA’s that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA’s are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA’s. The plants will become deregulated upon the earlier of one year after the expiry of a PPA or a decision to continue to operate the plant. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant and December 31, 2020.

The utilities are subject to a cost of service regulatory mechanism under which the AEUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for each utility is the aggregate of the AEUB approved investment in property, plant and equipment, less accumulated depreciation, plus an allowance for working capital. Rate base also excludes no-cost capital, which consists of unamortized contributions by utility customers for extensions to plant. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

The AEUB approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility’s debt and preferred shares. On July 2, 2004, the AEUB established a standardized approach for determining the rate of return on common equity for each utility regulated by the AEUB. This rate of return will be adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Government of Canada bond yields for the month of October as reported in the National Post. In January 2006, the AEUB clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply to each year of the test period in the utilities’ applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year.

The AEUB also established the capital structure for each utility and determined that any proposed changes to the approved capital structure which result from a material change in the investment risk of a utility will be addressed at utility specific rate applications.

Under the cost of service methodology, the utilities seek approval for their revenue requirement either through submission of general rate applications to the AEUB or a negotiated settlement process with interested parties. In the latter case, the AEUB monitors the negotiated settlement process and approves any agreement that is reached. The AEUB may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

Certain items in these consolidated financial statements are accounted for differently than they would be in the absence of rate regulation. CICA recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

Where regulatory decisions dictate, the utilities defer certain costs or revenues as assets or liabilities on the balance sheet and record them as expenses or revenues in the earnings statement as they collect or refund amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the AEUB renders a subsequent decision.

2. Accounting for rate regulated operations (continued)

Circumstances in which rate regulation affects the accounting for a transaction or event are described below. For these regulatory items, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate setting purposes, and, unless specifically indicated, is indeterminate.

The regulatory assets and liabilities comprise the following:

	2006	2005
<i>Regulatory assets – current:</i>		
Deferred hearing costs	\$ -	\$ 8.8
Deferred electricity costs	1.7	-
Other regulatory assets	11.6	10.3
	\$ 13.3	\$ 19.1
<i>Regulatory assets – non-current:</i>		
Regulatory other post employment benefits asset (Note 20)	\$ 27.6	\$ 22.0
Deferred electricity costs	7.1	5.4
Deferred hearing costs	1.4	1.6
Reserves for injuries and damages	2.0	5.4
Other regulatory assets	5.1	0.6
	\$ 43.2	\$ 35.0
<i>Regulatory liabilities – current:</i>		
Deferred electricity cost recoveries	\$ -	\$ 4.0
Reserves for injuries and damages	-	0.8
Other regulatory liabilities	0.5	1.6
	\$ 0.5	\$ 6.4
<i>Regulatory liabilities – non-current:</i>		
Regulatory pension liability (Note 20)	\$118.7	\$139.4
Deferred royalty credits	19.7	18.1
Deferred electricity cost recoveries	6.2	-
Deferred hearing costs	0.4	2.6
Reserves for injuries and damages	2.8	0.8
Other regulatory liabilities	1.0	1.0
	\$148.8	\$161.9

Employee future benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. The regulatory asset (liability) reflects an AEUB decision, effective January 1, 2000, to record costs of employee future benefits in the utilities when paid rather than accrued. The variances between the amounts paid and accrued for each of the defined benefit pension plans and the other post employment benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will be deferred until the plans are paid, settled or terminated.

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan cost in 2006 would have been \$19.5 million higher (2005 – \$1.6 million lower), and other post employment benefit plan cost in 2006 would have been \$3.5 million higher (2005 – \$3.3 million higher), in the absence of rate regulation.

Upon the adoption of the current accounting standard in 2000, the utilities had recorded deferred pension assets of \$23.0 million. The utilities have been earning an AEUB approved rate of return on these assets through customer rates as the assets form part of the utilities' AEUB approved rate base. In the absence of rate regulation, the utilities would not be able to earn a return on these assets. Consequently, revenues in 2006 would have been \$1.7 million

2. Accounting for rate regulated operations (continued)

lower (2005 – \$2.1 million lower). On October 11, 2006, the AEUB issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the utilities to continue to earn an AEUB approved rate of return on the unrecovered portion of these assets over the recovery period. In 2006, the utilities amortized \$5.1 million (2005 – nil) of the deferred pension asset.

Deferred electricity costs (recoveries)

Variances between ATCO Electric's actual and forecast transmission access payments may arise due to changes in tariffs charged by the Alberta Power Pool. The amount included in customer rates is based on forecast cost. Revenues are adjusted for changes in tariffs, and the variances are deferred until approval from the AEUB is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AEUB and not adjusted for variances between forecast and actual costs.

In Alberta, major transmission capital projects are planned by the Alberta Power Pool and directly assigned to one of the transmission facility owners in the province. Revenue requirement includes a return on forecast rate base. Whereas actual capital costs may vary from forecast capital costs, variances may arise between the return on forecast rate base and the return on actual rate base. Revenues are adjusted for these variances, and the variances are deferred until approval from the AEUB is obtained for refund to or collection from the Alberta Power Pool, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AEUB and not adjusted for variances between the returns on forecast and actual rate base.

Consequently, revenues in 2006 would have been \$1.2 million lower (2005 – \$23.4 million lower) in the absence of rate regulation.

Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AEUB regulatory proceedings. These costs are comprised primarily of legal and consulting expenses incurred by the utilities in addition to costs incurred by intervenor groups that have been reimbursed by the utilities as directed by the AEUB. Hearing costs are deferred to the balance sheet and are expensed using AEUB approved annual amounts that are collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the next general rate application or until a specific application is made to the AEUB requesting recovery from or refund to customers. GAAP requires that hearing costs be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been \$6.8 million lower (2005 – \$4.0 million higher) in the absence of rate regulation.

Reserves for injuries and damages

The AEUB has approved the use of reserves for injuries and damages by the utilities as a means of self-insurance. The reserves for injuries and damages are established based on annual amounts approved by the AEUB to be expensed by each utility and collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the following general rate application or until a specific application is made to the AEUB requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been \$3.6 million lower (2005 – \$1.1 million lower) in the absence of rate regulation.

For Alberta Power (2000), reserves for injuries and damages are recoverable under the terms of the PPA's on a straight line basis through 2008. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been \$1.0 million lower (2005 – \$1.0 million lower) in the absence of rate regulation.

2. Accounting for rate regulated operations (continued)

Deferred royalty credits

Under the terms of PPA's, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply are averaged over the term of each PPA. As such, royalty costs incurred are deferred and expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been \$1.6 million lower (2005 – \$4.0 million lower) in the absence of rate regulation.

Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

- a) ATCO Gas has received AEUB approval to defer:
 - i) Bad debt and collection agency fees incurred after June 1, 2004 related to billings prior to that date and associated late payment charges net of bad debt recoveries of \$(0.1) million (2005 – \$1.4 million);
 - ii) Charges from the Government of Alberta for funding of the office of the Utilities Consumer Advocate and the Consumer Protection and Consumer Choice Campaign, net of AEUB approved recoveries from customers, of \$(0.6) million (2005 – \$1.0 million); and,
 - iii) Removal and abandonment costs related to previously disposed of production properties, net of AEUB approved recoveries from customers, of nil (2005 – \$5.0 million).

Variances between the approved annual amounts and actual costs are deferred until the following general rate application or until a specific application is made to the AEUB requesting recovery from or refund to customers. GAAP requires that these net costs be expensed in the period in which they are incurred. Consequently, expenses in 2006 would have been \$8.1 million lower (2005 – \$2.1 million higher) in the absence of rate regulation. Liabilities of \$0.7 million are included in non-current regulatory liabilities (2005 – \$6.9 million in current regulatory assets and \$0.5 million in non-current regulatory assets).

- b) In October 2005, ATCO Gas filed an application with the AEUB to approve the sale of its Red Deer Operating Centre. In December 2005, the AEUB approved the sale and deferred its decision on the distribution of net proceeds of \$1.0 million until the Supreme Court of Canada rendered a judgment in the appeal regarding the Calgary Stores Block disposition and allocation of proceeds thereon. The Supreme Court of Canada rendered its decision on the Calgary Stores Block matter on February 9, 2006 and the AEUB complied with that decision on August 11, 2006. Subsequently, ATCO Gas submitted a filing to the AEUB to approve the allocation of the net proceeds from the sale of the Red Deer Operating Centre. On December 13, 2006, the AEUB issued a decision approving the distribution of the proceeds to ATCO Gas. GAAP requires that gains and losses related to asset dispositions be recognized in the period the disposition was made. Consequently, revenues in 2006 would have been \$1.0 million lower (2005 – \$1.0 million higher) in the absence of rate regulation.
- c) ATCO Pipelines has received AEUB approval to defer the variances between actual and AEUB approved forecast revenues and costs associated with the movement (receipt or delivery) of natural gas between ATCO Pipelines' system and other connected pipeline systems. ATCO Pipelines expects that the recovery of these deferral accounts will occur in the next general rate application. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2006 would have been \$0.9 million higher (2005 – \$0.1 million lower) and expenses would have been \$0.6 million lower (2005 – \$1.6 million lower) in the absence of rate regulation. Assets of \$2.7 million and \$0.2 million (2005 – \$2.2 million and nil) are included in current regulatory assets and non-current regulatory assets, respectively, and liabilities of \$0.5 million and \$0.3 million (2005 – \$1.6 million and nil) are included in current regulatory liabilities and non-current regulatory liabilities, respectively.

2. Accounting for rate regulated operations (continued)

- d) ATCO Pipelines has received AEUB approval to establish a deferral account for the Salt Cavern Storage facility to collect (i) the revenue requirements for return on rate base and associated income taxes related to the necessary working capital for the natural gas in storage, and (ii) the gains or losses associated with the sale of natural gas in the market upon withdrawal from storage. ATCO Pipelines is required to submit an application to the AEUB, either separately or in conjunction with a general rate application for that particular year, requesting recovery from or refund to customers of the deferral amount should the deferral account exceed \$2.0 million at the end of the annual injection/withdrawal cycle on March 31 of a particular year. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2006 would have been \$2.6 million lower (2005 – \$1.2 million lower) in the absence of rate regulation. Assets of \$3.7 million are included in non-current regulatory assets (2005 – \$1.2 million in current regulatory assets) in the balance sheet.
- e) In 2006, ATCO Pipelines received AEUB approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Pipelines' North and South transmission pipeline systems. Should the deferral account for either North or South exceed \$2.0 million, ATCO Pipelines may submit an application to the AEUB requesting recovery from or refund to customers of that particular deferral amount. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, expenses in 2006 would have been \$8.9 million higher in the absence of rate regulation. Assets of \$8.9 million are included in current regulatory assets in the balance sheet.

Other items affected by rate regulation

The AEUB permits an allowance for funds used ("AFU"), based on each utility's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes preferred share and common equity components, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

The utilities and the generating plants of Alberta Power (2000) follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 7).

3. Transfer of retail energy supply businesses

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. Proceeds of the transfer were \$90 million, of which \$45 million was paid at closing, and the remainder was paid on May 4, 2005. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

ATCO Pipelines, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical did not participate in this transfer and continue to purchase natural gas and electricity for sale to customers. In addition, the AEUB issued a decision that directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon storage facility for the 2004/2005 storage year, which ended on March 31, 2005, and issued a decision that terminated ATCO Pipelines' obligation to purchase natural gas for sale to customers effective October 31, 2005.

Although ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if DEML fails to perform. In certain events (including where DEML fails to supply

3. Transfer of retail energy supply businesses

natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AEUB to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a \$300 million guarantee supported by a \$235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations to DEML contemplated under the transaction agreements.

4. Regulatory matters

On March 17, 2006, ATCO Electric received a decision on its general tariff application for 2005 and 2006 which was filed with the AEUB in May 2005. The decision establishes the amount of revenue ATCO Electric can recover through its rates for electric distribution and transmission service provided to its customers for 2005 and 2006. In July and September 2005, the AEUB had approved interim refundable rates for distribution and transmission operations, respectively; revenues associated with these interim refundable rates were recorded in 2005. The impact of the decision for 2005 reduced earnings by \$1.3 million and was recorded in the first quarter of 2006. The impact of the decision for the full year 2006, as compared to the decision for the full year 2005, further reduced earnings by \$1.6 million. The decision also confirmed the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 9.5% in 2005 and is 8.93% in 2006.

On January 27, 2006, ATCO Gas received a decision on its general rate application which was filed with the AEUB in May 2005 for the 2005, 2006 and 2007 test years. The decision establishes the amount of revenue ATCO Gas can recover through distribution rates for natural gas distribution service to its customers over the period of 2005 to 2007. The decision also approved the return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity was 9.5% in 2005, is 8.93% in 2006, and will be 8.51% for 2007. The final impact of the decision will not be known until a subsequent regulatory process is finalized. A decision from the AEUB with respect to a second regulatory process that was pending at the end of 2005 was received on October 11, 2006; the effect of this decision on the earnings of the Corporation was not material.

The Corporation has a number of other regulatory filings and regulatory hearing submissions before the AEUB for which decisions have not been received. The outcome of these matters cannot be determined at this time.

5. TXU Europe settlement

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Corporation, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

Barking Power received a total of four distributions in settlement of its claim: a first distribution of £112.3 million (approximately \$257 million) on March 30, 2005, of which the Corporation's share was \$65.4 million; a second distribution of £32.2 million (approximately \$69.6 million) on August 2, 2005, of which the Corporation's share was \$17.7 million; a third distribution of £31.8 million (approximately \$65.2 million) on January 19, 2006, of which the Corporation's share was \$16.6 million; and a final distribution of £3.0 million (approximately \$6.2 million) on July 20, 2006, of which the Corporation's share was \$1.6 million. Income taxes of approximately \$28.1 million relating to the distributions have been paid. Income taxes of approximately \$0.4 million relating to the final distribution will be paid in 2007 as part of the Corporation's normal tax installments.

5. TXU Europe settlement (continued)

Based on the foreign currency exchange rate in effect at March 30, 2005, the Corporation's share of this settlement is expected to generate earnings after income taxes of approximately \$69 million, which will be recognized over the remaining term of the TXU Europe contract to September 30, 2010, at approximately \$11 million per year. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

6. Interest and other income

	2006	2005
Interest	\$39.3	\$29.0
Allowance for funds used by regulated operations	9.3	7.0
Gains on dispositions of property, plant and equipment	8.3	1.7
Other income (expense)	1.6	(1.1)
	\$58.5	\$36.6

7. Income taxes

The income tax provision differs from that computed using the statutory tax rates for the following reasons:

	2006		2005	
	\$526.8	%	\$477.0	%
Earnings before income taxes				
Income taxes, at statutory rates	\$208.0	39.5	\$193.8	40.6
Federal general tax reduction ⁽¹⁾	(23.2)	(4.4)	(18.1)	(3.8)
Manufacturing and processing tax credit	(7.7)	(1.5)	(7.5)	(1.6)
Resource allowance	(1.6)	(0.3)	(2.8)	(0.6)
Crown royalties and other non-deductible Crown payments	0.7	0.1	1.1	0.2
Foreign tax rate variance	(7.6)	(1.4)	(6.2)	(1.3)
Non-deductible interest on foreign financing	1.3	0.3	1.4	0.3
Large Corporations Tax	-	-	7.8	1.7
Change in future income taxes resulting from reduction in tax rates	(12.2)	(2.3)	-	-
Change in method of accounting for future income taxes in certain regulated operations	(4.0)	(0.8)	-	-
Unrecorded future income taxes relating to regulated operations	2.5	0.5	1.0	0.2
H.R. Milner income tax reassessment	7.4	1.4	-	-
Other	3.5	0.6	5.1	1.1
	167.1	31.7	175.6	36.8
Current income taxes	183.0		185.8	
Future income taxes (recoveries)	\$ (15.9)		\$ (10.2)	

⁽¹⁾ The federal general tax reduction of 7% is applicable to earnings that have not otherwise benefited from the manufacturing and processing tax credit and/or the resource allowance. An additional federal tax reduction of 5% (2005 – 3%) is applicable to earnings that have benefited from the resource allowance.

7. Income taxes (continued)

The future income tax liabilities (assets) comprise the following:

	2006	2005
Property, plant and equipment	\$212.2	\$222.7
Deferred assets and liabilities	(17.1)	(18.3)
Tax loss carryforwards	(0.1)	(0.3)
Other	-	0.3
	195.0	204.4
Less: Amounts included in current future income taxes	0.3	4.1
	\$194.7	\$200.3

At December 31, 2006, unrecorded future income tax liabilities of the regulated operations amounted to \$141.3 million and unrecorded future income tax assets of other operations amounted to \$0.5 million. The liabilities include \$14.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

In 2006, the Canada Revenue Agency ("CRA") issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation has made submissions to the CRA opposing the CRA's position. The impact of the reassessment is a \$12.4 million increase in interest and income tax expense, a \$12.4 million decrease in earnings and a \$28.8 million payment associated with the tax and interest assessed. It is expected that \$16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims. Due to the uncertainty as to whether the reassessment will ultimately be resolved in the Corporation's favour, the Corporation reduced earnings by \$12.4 million in 2006.

There are tax loss carryforwards of \$0.4 million for Canadian subsidiary corporations and \$7.6 million for a foreign subsidiary corporation for which no tax benefit has been recorded. The losses for Canadian subsidiary corporations begin to expire in 2010 and the losses for the foreign subsidiary corporation do not expire.

Income taxes paid amounted to \$187.0 million (2005 — \$178.6 million).

8. Purchase of Class A shares and other direct charges to retained earnings

	2006	2005
Purchase of Class A shares	\$64.4	\$7.5
Purchase of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. (Note 19)	0.3	-
	\$64.7	\$7.5

9. Property, plant and equipment

	Composite Depreciation Rates	2006		2005	
		Cost	Accumulated Depreciation	Cost	Accumulated Depreciation
Utilities	3.7%	\$6,490.4	\$2,411.1	\$6,022.0	\$2,240.8
Power Generation	3.2%	2,853.7	1,026.1	2,753.9	921.4
Global Enterprises	9.2%	269.5	140.8	270.3	127.1
Other	4.7%	26.7	6.7	27.7	6.1
		\$9,640.3	3,584.7	\$9,073.9	3,295.4
Property, plant and equipment less accumulated depreciation			6,055.6		5,778.5
Unamortized contributions by utility customers for extensions to plant			629.5		569.8
			\$5,426.1		\$5,208.7

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of \$374.6 million (2005 — \$323.6 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of \$114.2 million (2005 — \$91.1 million) and non-depreciable assets of \$52.3 million (2005 — \$41.3 million).

10. Other assets

	2006	2005
Accrued pension asset (Note 20)	\$157.1	\$192.2
Security deposits for debt	22.8	20.0
Deferred financing charges ⁽¹⁾	25.0	25.4
Other ⁽²⁾	24.8	31.5
	\$229.7	\$269.1

⁽¹⁾ Amortization of deferred financing charges, which was recorded in interest expense, amounted to \$2.8 million (2005 — \$2.8 million).

⁽²⁾ Amortization of certain other assets, which was recorded in depreciation and amortization, amounted to \$14.9 million (2005 — \$5.9 million).

11. Credit lines

At December 31, 2006, the Corporation has the following credit lines that enable it to obtain financing for general business purposes:

	2006			2005		
	Total	Used	Available	Total	Used	Available
Long term committed	\$326.0	\$47.4	\$278.6	\$326.0	\$11.9	\$314.1
Short term committed	600.0	14.0	586.0	600.0	-	600.0
Uncommitted	69.1	7.1	62.0	69.1	8.3	60.8
	\$995.1	\$68.5	\$926.6	\$995.1	\$20.2	\$974.9

Of the \$68.5 million used at December 31, 2006, \$47.0 million is included in long term debt and \$21.5 million represents outstanding letters of credit.

12. Long term debt and non-recourse long term debt

Long term debt

	2006	2005
CU Inc. debentures – unsecured		
2001 4.84% due November 2006	\$ -	\$ 175.0
2002 4.801% due November 2007	50.0	50.0
2000 6.97% due June 2008	100.0	100.0
1989 Series 10.20% due November 2009	125.0	125.0
1990 Series 11.40% due August 2010	125.0	125.0
2000 7.05% due June 2011	100.0	100.0
2004 5.096% due November 2014	100.0	100.0
2002 6.145% due November 2017	150.0	150.0
2004 5.432% due January 2019	180.0	180.0
1999 Series 6.8% due August 2019	300.0	300.0
1990 Second Series 11.77% due November 2020	100.0	100.0
2006 4.801% due November 2021	160.0	-
1991 Series 9.92% due April 2022	125.0	125.0
1992 Series 9.40% due May 2023	100.0	100.0
2004 5.896% due November 2034	200.0	200.0
2005 5.183% due November 2035	185.0	185.0
2006 5.032% due November 2036	160.0	-
Canadian Utilities Limited debentures – unsecured		
2002 6.14% due November 2012	100.0	100.0
	2,360.0	2,215.0
ATCO Midstream Ltd. credit facility, at BA rates, due June 2011, unsecured ⁽¹⁾	25.0	-
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2011, secured by a pledge of cash ⁽¹⁾	22.0	11.5
Other long term obligation, at 5.0%, due June 2007, unsecured	4.5	4.5
	\$2,411.5	\$2,231.0

Non-recourse long term debt

	2006	2005
Barking Power Limited project financing, payable in British pounds:		
At fixed rates averaging 7.95%, due to 2010	\$ 52.1	\$ 54.7
At LIBOR, due to 2010 ⁽¹⁾	85.5	89.6
Osborne Cogeneration Pty Ltd. project financing, payable in Australian dollars:		
At Bank Bill rates, due to 2013 ⁽¹⁾	1.7	1.8
At 7.3325%, due to 2013 ⁽¹⁾	31.8	34.4
ATCO Power Alberta Limited Partnership (“APALP”) project financing:		
At 7.54% to 2008, at LIBOR thereafter, due to 2016 ⁽¹⁾	2.6	3.8
At 7.317% to 2008, at LIBOR thereafter, due to 2016 ⁽¹⁾	3.6	5.4
At 7.50% to 2011, at LIBOR thereafter, due to 2016 ⁽¹⁾	83.8	87.5
Joffre project financing:		
At 7.286%, due to 2012 ⁽¹⁾	15.6	26.7
At 8.59%, due to 2020	32.0	32.0

12. Long term debt and non-recourse long term debt (continued)

Non-recourse long term debt (continued)

	2006	2005
Scotford project financing:		
At 5.212%, due to 2008, at BA rates thereafter, due to 2014 ⁽¹⁾	42.8	46.2
At 5.212%, due to 2008, at LIBOR thereafter, due to 2014 ⁽¹⁾	10.7	11.6
At 7.93%, due to 2022	26.1	26.9
Muskeg River project financing:		
At 5.287%, due 2007, at BA rates thereafter, due to 2014 ⁽¹⁾	40.8	44.4
At BA rates, due to 2014 ⁽¹⁾	0.1	0.3
At 7.56%, due to 2022	29.4	31.2
Brighton Beach project financing:		
At 5.8367%, due 2009, at BA or Canadian Eurodollar rates thereafter, due to 2019 ⁽¹⁾	8.9	9.4
At BA or Canadian Eurodollar rates, due to 2019 ⁽¹⁾	2.7	2.5
At 6.575%, due to 2019 ⁽¹⁾	36.1	37.8
At 6.924%, due to 2024	107.8	110.5
Cory project financing:		
At BA rates, due to 2011 ⁽¹⁾	0.3	0.3
At 6.346%, due to 2011 ⁽¹⁾	2.7	3.3
At 7.586%, due to 2025	36.5	37.4
At 7.601%, due to 2026	32.4	33.1
	686.0	730.8
Less: Amounts due within one year	59.3	57.0
	\$626.7	\$673.8

BA – Bankers' Acceptance

LIBOR – London Interbank Offered Rate

⁽¹⁾ The above interest rates have additional margin fees at a weighted average rate of 1.1% (2005 – 1.1%) (Note 21). The margin fees are subject to escalation.

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 96% (2005 – 96%) of total long term debt and non-recourse long term debt.

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2006 was \$1,415.2 million (2005 – \$1,342.4 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

- a) **Construction liens** – Represents liens currently registered against project assets. Effective September 30, 2005, ATCO Power entered into an indemnity agreement with Brighton Beach Power Ltd. obligating it to cover any cash shortfalls associated with clearing the construction liens registered against the project. This agreement allowed the project to achieve financial completion under the terms of the project financing agreement. The maximum amount of the indemnity is \$8.3 million. Canadian Utilities Limited issued a guarantee to Brighton Beach Power Ltd. guaranteeing the payments under the indemnity agreement. The indemnity and the guarantee are reduced as the liens are settled.

12. Long term debt and non-recourse long term debt (continued)

- b) **Project cash flows** — Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts (“MW”) for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2006, no amounts were outstanding under the guarantee.
- c) **Reserve amounts** — Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project’s financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2006, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil ⁽¹⁾	\$6.9
Brighton Beach project financing	Nil ⁽²⁾	Nil
Cory project financing	Nil ⁽¹⁾	\$3.9
Joffre project financing	Nil ⁽³⁾	\$4.7
Muskeg River project financing	Nil ⁽¹⁾	\$5.0
Scotford project financing	Nil ⁽¹⁾	\$5.6

- ⁽¹⁾ No major maintenance reserve required for this financing.
⁽²⁾ Reserve requirements of \$0.3 million met with project cash flows.
⁽³⁾ Reserve requirements of \$1.0 million met with project cash flows.

- d) **Prepaid operating and maintenance fee** — Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by \$1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2006, the maximum value of the guarantee is \$30.0 million.
- e) **Purchase project assets** — Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:
- (i) where all of the following events have occurred:
 - the insolvency of ATCO Power;
 - the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
 - the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;
 - (ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
 - a deliberate or willful breach of a project financing agreement; or
 - where ATCO Power has failed to co-operate with the lenders in a sale of the project; and
 - (iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power’s project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

12. Long term debt and non-recourse long term debt (continued)

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2006, no such events have occurred.

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts.

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects subject to guarantees, excluding Barking Power.

The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Minimum debt repayments

The minimum annual debt repayments for each of the next five years are as follows:

	Long Term Debt	Non-Recourse Long Term Debt	Total
2007	\$ 54.5	\$ 59.3	\$113.8
2008	100.0	77.9	177.9
2009	125.0	72.4	197.4
2010	125.0	79.4	204.4
2011	147.0	44.8	191.8
	\$551.5	\$333.8	\$885.3

Of the \$113.8 million due in 2007, \$54.5 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest expense is as follows:

	2006	2005
Long term debt	\$161.0	\$154.5
Non-recourse long term debt	49.0	51.4
Notes payable	0.3	-
Bank indebtedness	1.5	1.3
Amortization of deferred financing charges	2.8	2.8
Interest on H.R. Milner tax reassessment (Note 7)	8.3	-
	\$222.9	\$210.0

Interest paid amounted to \$220.8 million (2005 — \$207.2 million).

12. Long term debt and non-recourse long term debt (continued)

Fair values

Fair values for the above debt, determined using quoted market prices for the same or similar issues, are shown below. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

	2006	2005
<i>Long term debt</i>		
Fixed rate	\$2,741.4	\$2,656.2
Floating rate	47.0	11.5
	\$2,788.4	\$2,667.7
<i>Non-recourse long term debt</i>		
Fixed rate	\$ 635.3	\$ 683.9
Floating rate	90.2	94.5
	\$ 725.5	\$ 778.4

13. Deferred credits

	2006	2005
Accrued other post employment benefits liability (Note 20)	\$ 45.1	\$ 35.4
Deferred revenues (Note 5)	46.8	59.6
Deferred availability incentives	39.6	59.7
Asset retirement obligations	69.4	62.2
Accrued equipment repairs and maintenance	7.5	8.8
Other	20.6	28.1
	\$229.0	\$253.8

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to \$10.6 million (2005 – \$8.9 million).

The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPA's. Each quarter, the Corporation uses these estimates to forecast the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Asset retirement obligations

Changes in asset retirement obligations are summarized below:

	2006	2005
Obligations at beginning of year	\$62.2	\$34.7
Obligations incurred	3.7	25.4
Accretion expense	3.5	2.1
Obligations at end of year	\$69.4	\$62.2

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately \$131 million, which will be incurred between 2007 and 2052. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.7%.

14. Equity preferred shares

Authorized and issued

Authorized: An unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value (dollars)	Redemption Dates	2006		2005	
			Shares	Amount	Shares	Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	\$25.00	Open	2,277,675	\$ 56.9	2,277,675	\$ 56.9
5.3% Series R	\$25.00	Open	2,146,730	53.7	2,146,730	53.7
6.6% Series S	\$25.00	Open	635,700	15.9	635,700	15.9
5.8% Series W	\$25.00	See below	6,000,000	150.0	6,000,000	150.0
6.0% Series X	\$25.00	See below	6,000,000	150.0	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	\$25.00	December 2, 2011	1,600,000	40.0	1,600,000	40.0
4.35% Series T	\$25.00	December 2, 2011	1,600,000	40.0	1,600,000	40.0
4.35% Series U	\$25.00	December 2, 2011	800,000	20.0	800,000	20.0
5.25% Series V	\$25.00	October 3, 2007	4,400,000	110.0	4,400,000	110.0
				\$636.5		\$636.5

The dividends payable on the Series O, T, U, and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are \$666.8 million (2005 — \$669.1 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until March 1, 2012.

The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until June 1, 2012.

15. Class A and Class B shares

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2004	82,740,586	\$374.8	44,042,484	\$139.5	126,783,070	\$514.3
Purchased	(228,600)	(1.0)	-	-	(228,600)	(1.0)
Stock options exercised	338,000	5.8	-	-	338,000	5.8
Converted: Class B to Class A	26,200	0.1	(26,200)	(0.1)	-	-
December 31, 2005	82,876,186	379.7	44,016,284	139.4	126,892,470	519.1
Purchased	(1,832,200)	(8.4)	-	-	(1,832,200)	(8.4)
Stock options exercised	327,900	5.3	-	-	327,900	5.3
Converted: Class B to Class A	84,800	0.3	(84,800)	(0.3)	-	-
December 31, 2006	81,456,686	\$376.9	43,931,484	\$139.1	125,388,170	\$516.0

From January 1, 2007 to February 16, 2007, 600 Class A non-voting shares were issued with respect to the exercises of stock options and 5,000 Class B common shares were converted to Class A non-voting shares.

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2006	2005	2006	2005
	<i>(Unaudited)</i>			
Weighted average shares outstanding	125,321,693	126,928,689	126,218,722	126,901,614
Effect of dilutive stock options	512,786	685,048	468,457	551,357
Weighted average diluted shares outstanding	125,834,479	127,613,737	126,687,179	127,452,971

Share owner rights

The owners of the Class A non-voting shares and the Class B common shares are entitled to share equally, on a share for share basis, in all dividends declared by Canadian Utilities Limited on either of such classes of shares as well as the remaining property of Canadian Utilities Limited upon dissolution. The owners of the Class B common shares are entitled to vote and to exchange at any time each share held for one Class A non-voting share.

15. Class A and Class B shares (continued)

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Normal course issuer bid

On May 20, 2005, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The bid expired on May 19, 2006. Over the life of the bid, 348,100 shares were purchased, of which 195,600 were purchased in 2005 and 152,500 were purchased in 2006. On May 23, 2006, Canadian Utilities Limited commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2007. From May 23, 2006, to February 16, 2007, 1,679,700 shares have been purchased, all of which were purchased in 2006.

Special dividend

The Corporation paid a Special Dividend of \$0.25 per Class A non-voting and Class B common share on September 1, 2006.

16. Stock based compensation plans

Stock option plan

Of the 6,400,000 Class A non-voting shares reserved for issuance in respect of options under Canadian Utilities Limited's stock option plan, 2,626,800 Class A non-voting shares are available for issuance at December 31, 2006. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

Changes in shares under option are summarized below:

	2006		2005	
	Class A Shares	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	1,415,500	\$21.59	1,555,600	\$19.45
Granted	121,000	43.45	204,000	30.50
Exercised	(327,900)	16.62	(338,000)	17.07
Cancelled	(600)	24.52	(6,100)	24.93
Options at end of year	1,208,000	\$25.12	1,415,500	\$21.59

16. Stock based compensation plans (continued)

Information about stock options outstanding at December 31, 2006 is summarized below:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
\$17.23 - \$18.87	342,600	2.9	\$17.84	342,600	\$17.84
\$20.65 - \$28.65	540,400	3.3	23.60	494,400	23.39
\$30.25 - \$43.56	325,000	8.4	35.33	40,800	30.50
\$17.23 - \$43.56	1,208,000	4.6	\$25.12	877,800	\$21.56

In 2006, Canadian Utilities Limited granted 121,000 options to purchase Class A non-voting shares at a weighted average exercise price of \$43.45 per share. The options have a term of ten years and vest over the first five years.

On January 2, 2007, Canadian Utilities Limited granted 161,500 options to purchase Class A non-voting shares at an exercise price of \$47.84 per share. The options have a term of ten years and vest over the first five years.

Changes in contributed surplus are summarized below:

	2006	2005
Contributed surplus at beginning of year	\$0.7	\$0.4
Stock option expense	0.5	0.3
Contributed surplus at end of year	\$1.2	\$0.7

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2006 at \$6.24 per option (2005 — \$3.21 per option) using the following weighted average assumptions:

	2006	2005
Risk free interest rate	4.0%	4.0%
Expected holding period prior to exercise	6.2 years	6.3 years
Share price volatility	11.9%	11.7%
Estimated annual Class A share dividend	2.5%	3.5%

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and Class I Non-Voting shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to \$2.4 million (2005 — \$9.0 million).

17. Changes in non-cash working capital

	2006	2005
<i>Operating activities, changes related to:</i>		
Accounts receivable	\$(25.6)	\$ (6.7)
Inventories	0.5	85.3
Regulatory assets	(10.6)	(1.4)
Prepaid expenses	(3.0)	(1.7)
Accounts payable and accrued liabilities	1.7	29.3
Income taxes	6.4	(12.0)
Future income taxes	(3.8)	5.3
Regulatory liabilities	(5.2)	(7.9)
	\$(39.6)	\$ 90.2
<i>Investing activities, changes related to:</i>		
Inventories	\$ (8.1)	\$ (1.5)
Prepaid expenses	(0.3)	0.1
Accounts payable and accrued liabilities	(6.2)	9.0
Income taxes	(3.7)	(11.0)
	\$(18.3)	\$ (3.4)
<i>Financing activities, changes related to:</i>		
Accounts receivable	\$ (0.1)	\$ 3.1

18. Joint ventures

The Corporation's interest in joint ventures is summarized below:

	2006	2005
<i>Statement of earnings</i>		
Revenues	\$ 533.0	\$ 528.6
Operating expenses	328.1	355.1
Depreciation and amortization	40.4	43.1
Interest	41.2	41.5
	123.3	88.9
Interest and other income	8.9	7.7
Earnings from joint ventures before income taxes	\$ 132.2	\$ 96.6
<i>Balance sheet</i>		
Current assets	\$ 266.9	\$ 247.4
Current liabilities	(174.0)	(159.6)
Property, plant and equipment	933.2	922.3
Deferred items – net	(93.1)	(101.3)
Non-recourse long term debt	(465.2)	(504.2)
Investment in joint ventures	\$ 467.8	\$ 404.6
<i>Statement of cash flows</i>		
Operating activities	\$ 180.8	\$ 175.4
Investing activities	(19.1)	(16.0)
Financing activities	(131.0)	(79.1)
Foreign currency translation	14.1	(9.5)
Increase in cash position	\$ 44.8	\$ 70.8

Current assets include cash of \$160.9 million (2005 – \$118.6 million) which is only available for use within the joint ventures (see Note 5).

19. Related party transactions

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of \$2.2 million (2005 – \$2.5 million), provided computer operations and systems development services totaling \$2.4 million (2005 – \$5.0 million), recovered administrative expenses totaling \$2.4 million (2005 – \$2.4 million) and incurred administrative expenses and corporate signature rights totaling \$8.6 million (2005 – \$7.1 million). Also, in transactions with an entity related through common control, the Corporation provided security services and recovered administrative expenses totaling \$0.2 million (2005 – \$0.2 million) and incurred advertising and promotion expenses totaling \$1.7 million (2005 – \$1.4 million).

At December 31, 2006, accounts receivable due from related parties amounted to \$4.9 million (2005 – \$1.8 million) and accounts payable due to related parties amounted to \$3.2 million (2005 – \$0.5 million).

These transactions are in the normal course of business and under normal commercial terms.

On October 1, 2006, the Corporation purchased the common shares of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. from an affiliate corporation for \$0.5 million cash, partially offset by the forgiveness of \$0.4 million of debt owed by the Corporation to the affiliate corporation. This purchase was recorded at carrying value, resulting in a charge to retained earnings of \$0.3 million.

20. Employee future benefits

The Corporation maintains defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases.

20. Employee future benefits (continued)

Information about the Corporation's benefit plans, in aggregate, is as follows:

	2006		2005	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Benefit plan assets, obligations and funded status</i>				
<i>Market value of plan assets:</i>				
Beginning of year	\$1,561.1	\$ -	\$1,402.1	\$ -
Actual return on plan assets	187.3	-	197.0	-
Employee contributions	3.7	-	4.0	-
Benefit payments	(39.8)	-	(36.4)	-
Payments to defined contribution plans ⁽¹⁾	(8.2)	-	(5.6)	-
End of year	\$1,704.1	\$ -	\$1,561.1	\$ -
<i>Accrued benefit obligations:</i>				
Beginning of year	\$1,485.0	\$ 80.3	\$1,232.7	\$ 67.0
Current service cost	38.0	3.0	32.2	2.5
Interest cost	80.8	4.2	73.9	4.2
Employee contributions	3.7	-	4.0	-
Benefit payments from plan assets ⁽²⁾	(39.8)	-	(36.4)	-
Benefit payments by employer	(4.3)	(1.8)	(4.7)	(1.9)
Experience losses (gains) ⁽³⁾	78.6	(2.2)	183.3	8.5
End of year	\$1,642.0	\$ 83.5	\$1,485.0	\$ 80.3
<i>Funded status:</i>				
Excess (deficiency) of assets over obligations	\$ 62.1	\$(83.5)	\$ 76.1	\$(80.3)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	316.0	17.7	369.5	21.9
Unrecognized net transitional liability (asset)	(221.0)	20.7	(253.4)	23.0
Accrued asset (liability) (Notes 10, 13)	\$ 157.1	\$(45.1)	\$ 192.2	\$(35.4)
Regulatory asset (liability) ⁽⁴⁾ (Note 2)	\$ (118.7)	\$ 27.6	\$ (139.4)	\$ 22.0

⁽¹⁾ Employer contributions for certain of the Corporation's defined contribution pension plans are paid from the assets of the defined benefit pension plans.

⁽²⁾ Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.

⁽³⁾ Changes in assumptions regarding the average compensation rate increase for the year and age at retirement resulted in experience losses in 2006 of approximately \$66 million for the pension benefit plans. A change in the liability discount rate assumption resulted in experience losses in 2005 of approximately \$178 million for the pension benefit plans.

⁽⁴⁾ The regulatory asset (liability) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

20. Employee future benefits (continued)

	2006		2005	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
<i>Components of benefit plan cost:</i>				
Current service cost	\$ 38.0	\$ 3.0	\$ 32.2	\$ 2.5
Interest cost	80.8	4.2	73.9	4.2
Actual return on plan assets	(187.3)	-	(197.0)	-
Experience losses (gains) on accrued benefit obligations	78.6	(2.2)	183.3	8.5
	10.1	5.0	92.4	15.2
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	107.6	-	108.5	-
Unrecognized portion of experience gains (losses) on accrued benefit obligations	(78.6)	2.2	(183.3)	(8.5)
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	24.5	2.0	15.5	0.6
Amortization of net transitional liability (asset)	(32.4)	2.3	(32.8)	2.3
	21.1	6.5	(92.1)	(5.6)
Defined benefit plans cost	31.2	11.5	0.3	9.6
Defined contribution plans cost	9.7	-	7.0	-
Total cost	40.9	11.5	7.3	9.6
Less: Capitalized	1.9	2.7	1.4	2.3
Less: Unrecognized defined benefit plans cost (income) ⁽¹⁾⁽²⁾	19.5	3.5	(1.6)	3.3
Net cost recognized ⁽²⁾	\$ 19.5	\$ 5.3	\$ 7.5	\$ 4.0

⁽¹⁾ The unrecognized defined benefit plans cost (income) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

⁽²⁾ Net cost recognized for pension benefit plans in the three months ended December 31, 2006 includes the amortization of \$5.1 million of the deferred pension assets recorded by the Corporation upon the adoption of the current accounting standard in 2000. On October 11, 2006, the AEUB approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).

In the unaudited three months ended December 31, 2006, net cost of \$7.8 million (2005 – \$1.7 million) was recognized for pension benefit plans and net cost of \$1.6 million (2005 – \$0.6 million) was recognized for other post employment benefit plans.

20. Employee future benefits (continued)

Weighted average assumptions

	2006		2005	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Assumptions regarding benefit plan cost:</i>				
Expected long term rate of return on plan assets				
for the year	6.1%	-	6.9%	-
Liability discount rate for the year	5.1%	5.1%	5.9%	5.9%
Average compensation increase for the year	3.5%	-	3.25%	-
<i>Assumptions regarding accrued benefit obligations:</i>				
Liability discount rate at December 31	5.1%	5.1%	5.1%	5.1%
Long term inflation rate	2.5%	(1)	2.5%	(1)

(1) The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 8.5% for 2006 grading down over 7 years to 4.5% (2005 – 9.3% for 2005 grading down over 8 years to 4.5%), and, for other medical and dental costs, 4.0% for 2006 and thereafter (2005 – 4.0% for 2005 and thereafter).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2006 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2006 Pension Benefit Plans		2006 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase ⁽¹⁾	-	\$(3.4)	-	-
1% decrease ⁽¹⁾	-	\$ 3.4	-	-
Liability discount rate				
1% increase ⁽¹⁾	\$ (79.5)	\$(6.4)	\$(3.7)	\$(0.4)
1% decrease ⁽¹⁾	\$101.7	\$ 7.5	\$ 4.7	\$ 0.5
Future compensation rate				
1% increase ⁽¹⁾	\$ 22.9	\$ 2.9	-	-
1% decrease ⁽¹⁾	\$(20.8)	\$(2.6)	-	-
Long term inflation rate				
1% increase ⁽¹⁾⁽²⁾⁽³⁾	\$ 34.5	\$ 3.9	\$ 4.2	\$ 0.7
1% decrease ⁽¹⁾⁽³⁾	\$(60.4)	\$(6.9)	\$(3.4)	\$(0.5)

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.

(3) The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

20. Employee future benefits (continued)

Pension benefit plan assets

	2006		2005	
	Amount	%	Amount	%
<i>Plan asset mix:</i>				
Equity securities ⁽¹⁾	\$1,028.7	60.4	\$ 922.9	59.1
Fixed income securities ⁽²⁾	605.6	35.5	567.7	36.4
Real estate ⁽³⁾	32.7	1.9	31.1	2.0
Cash and other assets ⁽⁴⁾	37.1	2.2	39.4	2.5
	\$1,704.1	100.0	\$1,561.1	100.0

⁽¹⁾ Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2006, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are \$236.7 million and \$238.2 million, respectively (2005 – \$144.0 million and \$174.0 million, respectively).

⁽²⁾ Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.

⁽³⁾ Real estate consists of investments in closed-end real estate funds.

⁽⁴⁾ Cash and other assets consist of cash, short term notes and money market funds.

At December 31, 2006, plan assets include long term debt of CU Inc. having a market value of \$8.7 million (2005 – \$6.0 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of \$19.1 million (2005 – \$17.6 million) and Class I Non-Voting shares of ATCO Ltd. having a market value of \$18.2 million (2005 – \$14.8 million).

Funding

Employees are required to contribute a percentage of their salary to the defined benefit pension plans. The Corporation is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2004, the Corporation is continuing a contribution holiday that began on April 1, 1996. The next actuarial valuation for funding purposes is required as of December 31, 2007.

Included in the accrued benefit obligations are certain supplementary defined benefit pension plans that are paid by the Corporation out of general revenues. These supplementary plans had accrued benefit obligations of \$84.2 million at December 31, 2006 (2005 – \$77.4 million).

21. Risk management and financial instruments

The Corporation is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. The Power Generation segment is affected by the cost of natural gas and the price of electricity in the Province of Alberta and the United Kingdom and the Global Enterprises segment is affected by the cost of natural gas and the price of natural gas liquids. In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

21. Risk management and financial instruments (continued)

Interest rate risk

Long term debt and non-recourse long term debt have variable interest rates that have been hedged through the following interest rate swap agreements:

Swap Fixed Interest Rate ⁽¹⁾	Variable Debt Interest Rate	Completion Date	Principal/Face Value	
			2006	2005
5.287%	90 day BA	December 2007	\$ 40.8	\$ 44.4
5.212%	90 day BA	September 2008	54.2	59.2
7.54%	90 day BA	November 2008	2.6	3.8
7.317%	90 day BA	December 2008	3.6	5.4
5.8367%	90 day BA	June 2009	8.9	9.4
6.346%	90 day BA	June 2011	2.7	3.3
7.50%	6 month LIBOR	December 2011	83.8	87.5
7.286%	90 day BA	September 2012	24.0	28.2
7.3325%	Bank Bill Rate in Australia	December 2013	31.8	34.4
6.575%	90 day BA	March 2019	36.1	37.8
			\$288.5	\$313.4

BA – Bankers' Acceptance

LIBOR – London Interbank Offered Rate

⁽¹⁾ The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 12).

Foreign exchange rate risk

The Corporation has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates.

The Corporation has entered into foreign exchange forward contracts in order to fix the exchange rate on certain planned equipment expenditures denominated in U.S. dollars and Euros. At December 31, 2006, the contracts consist of purchases of \$0.2 million U.S. (2005 – \$2.6 million U.S.) and sales of 3.0 million Euros (2005 – 2.0 million Euros).

Energy commodity price risk

In March 2004, the AEUB issued a decision respecting the operation of ATCO Gas' Carbon storage facility for the 2004/2005 storage year, which ended on March 31, 2005. The decision directed ATCO Gas to continue to reserve 16.7 petajoules of storage capacity for the benefit of utility customers. As a result of an AEUB approved storage plan, ATCO Gas entered into certain energy contracts for the forward purchase and sale of natural gas for storage purposes. All associated costs and benefits of these contracts were passed to customers through regulated rates and, accordingly, ATCO Gas did not bear any risk for price fluctuations provided that the contracts were in accordance with the storage plan. Since April 1, 2005, ATCO Gas has leased the entire storage capacity of the Carbon facility to ATCO Midstream.

21. Risk management and financial instruments (continued)

Fair values

The fair values of derivatives have been estimated using year-end market rates. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.

	2006			2005		
	Notional Principal	Fair Value (Payable) Receivable	Maturity	Notional Principal	Fair Value (Payable) Receivable	Maturity
Interest rate swaps	\$288.5	\$(7.3)	2007-2019	\$313.4	\$(10.5)	2007-2019
Foreign exchange forward contracts	\$ 4.6	\$ 0.3	2007	\$ 5.9	\$ (0.1)	2006

Credit risk

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies. Accounts receivable credit risk is reduced by a large and diversified customer base, requirement of letters of credit, and, for regulated operations other than Alberta Power (2000), the ability to recover an estimate for doubtful accounts through approved customer rates.

22. Commitments and contingencies

Commitments

The Corporation has contractual obligations in the normal course of business; future minimum payments are as follows:

	2007	2008	2009	2010	2011	Total of All Subsequent Years
Operating leases ⁽¹⁾	\$ 18.5	\$ 15.8	\$ 8.8	\$ 7.7	\$ 6.0	\$ 4.8
Purchase obligations:						
Coal purchase contracts ⁽²⁾	47.7	48.9	50.3	51.8	53.4	355.6
Natural gas purchase contracts ⁽³⁾	52.9	52.9	52.9	52.9	22.1	18.9
Operating and maintenance agreements ⁽⁴⁾	21.2	24.1	21.2	20.6	17.8	93.3
	\$140.3	\$141.7	\$133.2	\$133.0	\$99.3	\$472.6

⁽¹⁾ Operating leases are comprised primarily of long term leases for office premises and equipment.

⁽²⁾ Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants.

⁽³⁾ Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants.

⁽⁴⁾ ATCO Power has long term service agreements with suppliers to provide operating and maintenance services at certain of its generating plants.

Contingencies

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a

22. Commitments and contingencies (continued)

risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the AEUB.

On December 23, 2005, the Government of Canada filed a claim in the amount of \$70 million which alleges that the Corporation is liable for the destruction of property owned by the Governments of Canada and the United States. The Corporation believes that the claim is defensible and, in any event, has sufficient insurance coverage in place to cover any material amounts that might become payable as a result of the claim. Accordingly, the claim is not expected to have any material impact on the financial position of the Corporation.

The Corporation is party to a number of other disputes and lawsuits in the normal course of business. The Corporation believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

As a result of decisions of the Supreme Court of Canada in *Garland vs. Consumers' Gas Co.*, the imposition of late payment penalties on utility bills has been called into question. The Corporation is unable to determine at this time the impact, if any, that these decisions will have on the Corporation.

23. Segmented information

Description of segments

The Corporation operates in the following business segments:

The **Utilities** Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transportation of natural gas by ATCO Pipelines, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated complementary projects by ATCO Utility Services.

The **Power Generation** Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power, the regulated supply of electricity by Alberta Power (2000), and the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies.

The **Global Enterprises** Business Group includes the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec, the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek's subsidiary, ATCO I-Tek Business Services and the sale of travel services to both business and consumer sectors by ATCO Travel. The Corporation sold its 50% interest in Genics, a manufacturer of wood preservation products, effective August 1, 2006.

The Corporate and Other segment includes commercial real estate owned by the Corporation in Alberta.

23. Segmented information (continued)

Segmented results – Three months ended December 31

2006 2005	Utilities	Power Generation ⁽²⁾	Global Enterprises ⁽²⁾	Corporate and Other	Intersegment Eliminations	Consolidated
<i>(Unaudited)</i>						
Revenues – external	\$308.4 \$299.1	\$226.7 \$211.0	\$135.6 \$169.9	\$ 0.4 \$ 0.3	\$ - \$ -	\$671.1 \$680.3
Revenues – intersegment ⁽¹⁾	6.3 6.4	- -	38.3 30.0	2.9 2.9	(47.5) (39.3)	- -
Revenues	\$314.7 \$305.5	\$226.7 \$211.0	\$173.9 \$199.9	\$ 3.3 \$ 3.2	\$(47.5) \$(39.3)	\$671.1 \$680.3
Earnings attributable to Class A and Class B shares	\$ 43.7 \$ 32.5	\$ 36.9 \$ 36.7	\$ 27.3 \$ 27.6	\$(6.5) \$(7.5)	\$ (1.4) \$ (0.2)	\$100.0 \$ 89.1

(1) Intersegment revenues are recognized on the basis of prevailing market or regulated prices.

(2) In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation

23. Segmented information (continued)

Segmented results – Year ended December 31

2006 2005	Utilities	Power Generation ⁽²⁾	Global Enterprises ⁽²⁾	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	\$1,086.2 \$1,173.5	\$ 799.5 \$ 770.7	\$543.3 \$570.4	\$ 1.4 \$ 1.2	\$ - \$ -	\$2,430.4 \$2,515.8
Revenues – intersegment ⁽¹⁾	24.6 22.4	- -	123.9 108.6	11.3 11.2	(159.8) (142.2)	- -
Revenues	1,110.8 1,195.9	799.5 770.7	667.2 679.0	12.7 12.4	(159.8) (142.2)	2,430.4 2,515.8
Operating expenses	601.4 716.9	431.3 420.4	490.5 533.1	18.7 24.4	(151.2) (140.9)	1,390.7 1,553.9
Depreciation and amortization	220.2 189.3	95.4 95.8	31.5 24.8	1.4 1.6	- -	348.5 311.5
Interest expense	132.5 124.9	92.2 84.8	2.2 2.4	162.4 154.6	(166.4) (156.7)	222.9 210.0
Interest and other income	(20.3) (11.8)	(11.9) (9.3)	(4.1) (2.0)	(188.6) (170.2)	166.4 156.7	(58.5) (36.6)
Earnings before income taxes	177.0 176.6	192.5 179.0	147.1 120.7	18.8 2.0	(8.6) (1.3)	526.8 477.0
Income taxes	45.4 60.2	69.7 70.2	46.1 41.9	8.7 3.7	(2.8) (0.4)	167.1 175.6
	131.6 116.4	122.8 108.8	101.0 78.8	10.1 (1.7)	(5.8) (0.9)	359.7 301.4
Dividends on equity preferred shares	10.4 10.4	3.6 3.6	- -	21.8 21.8	- -	35.8 35.8
Earnings attributable to Class A and Class B shares	\$ 121.2 \$ 106.0	\$ 119.2 \$ 105.2	\$101.0 \$ 78.8	\$(11.7) \$(23.5)	\$ (5.8) \$ (0.9)	\$ 323.9 \$ 265.6
Total assets	\$3,799.0 \$3,526.8	\$2,240.0 \$2,219.6	\$278.1 \$303.7	\$576.2 \$614.9	\$100.2 \$152.8	\$6,993.5 \$6,817.8
Purchase of property, plant and equipment	\$ 505.0 \$ 472.9	\$ 48.1 \$ 41.2	\$ 14.2 \$ 11.9	\$ 0.4 \$ 0.7	\$ - \$ -	\$ 567.7 \$ 526.7

⁽¹⁾ Intersegment revenues are recognized on the basis of prevailing market or regulated prices.

⁽²⁾ In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation.

Geographic segments

	Domestic		Foreign		Consolidated	
	2006	2005	2006	2005	2006	2005
Revenues	\$2,130.6	\$2,253.6	\$299.8	\$262.2	\$2,430.4	\$2,515.8
Property, plant and equipment	\$5,099.5	\$4,905.9	\$326.6	\$302.8	\$5,426.1	\$5,208.7