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CANADIAN UTILITIES LIMITED
An ATCO Company

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2005

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

February 10, 2006

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, 2005 and 2004 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, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

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

		Three Months Ended December 31		Year Ended December 31	
	Note	**2005**	2004	**2005**	2004
		(Unaudited)			
Revenues	3	**$ 680.3**	$ 637.0	**$2,515.8**	$3,011.4
Costs and expenses					
Natural gas supply	3	**18.3**	39.7	**162.2**	847.8
Purchased power	3	**12.2**	15.4	**45.4**	95.8
Operation and maintenance		**261.7**	235.2	**1,003.6**	872.3
Selling and administrative		**57.3**	43.5	**190.4**	158.2
Depreciation and amortization		**84.5**	81.2	**311.5**	291.5
Interest	11	**51.4**	52.9	**210.0**	203.7
Franchise fees		**49.5**	37.5	**152.3**	133.4
		534.9	505.4	**2,075.4**	2,602.7
		145.4	131.6	**440.4**	408.7
Gain on transfer of retail energy supply businesses	3	**-**	-	**-**	63.3
Interest and other income	6	**10.6**	10.4	**36.6**	30.8
Earnings before income taxes		**156.0**	142.0	**477.0**	502.8
Income taxes	7	**58.0**	42.8	**175.6**	158.0
		98.0	99.2	**301.4**	344.8
Dividends on equity preferred shares		**8.9**	8.9	**35.8**	35.8
Earnings attributable to Class A and Class B shares	3	**89.1**	90.3	**265.6**	309.0
Retained earnings at beginning of period		**1,670.4**	1,548.3	**1,603.4**	1,435.4
		1,759.5	1,638.6	**1,869.0**	1,744.4
Dividends on Class A and Class B shares		**34.9**	33.6	**139.6**	134.4
Purchase of Class A shares		**2.7**	1.6	**7.5**	6.6
Retained earnings at end of period		**$1,721.9**	$1,603.4	**$1,721.9**	$1,603.4
Earnings per Class A and Class B share	14	**$ 0.70**	$ 0.71	**$ 2.09**	$ 2.44
Diluted earnings per Class A and Class B share	14	**$ 0.69**	$ 0.71	**$ 2.08**	$ 2.43
Dividends paid per Class A and Class B share	14	**$ 0.275**	$ 0.265	**$ 1.10**	$ 1.06

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

		December 31	
	Note	**2005**	2004
ASSETS			
Current assets			
Cash and short term investments	17	**$ 824.6**	$ 699.5
Accounts receivable		**351.3**	372.8
Inventories		**88.0**	172.9
Future income taxes	7	**-**	0.3
Regulatory assets	2	**19.1**	5.4
Prepaid expenses		**19.9**	19.1
		1,302.9	1,270.0
Property, plant and equipment	8	**5,208.7**	5,042.5
Regulatory assets	2	**35.0**	30.4
Other assets	9	**269.1**	274.6
		$6,815.7	$6,617.5
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness	10	**$ 0.2**	$ 1.2
Accounts payable and accrued liabilities		**340.5**	283.3
Income taxes payable		**26.7**	42.6
Future income taxes	7	**4.1**	-
Regulatory liabilities	2	**6.4**	13.6
Long term debt due within one year	11	**-**	5.3
Non-recourse long term debt due within one year	11	**57.0**	50.6
		434.9	396.6
Future income taxes	7	**200.3**	222.4
Regulatory liabilities	2	**161.9**	165.6
Deferred credits	12	**253.8**	146.8
Long term debt	11	**2,231.0**	2,171.0
Non-recourse long term debt	11	**673.8**	760.9
Equity preferred shares	13	**636.5**	636.5
Class A and Class B share owners' equity			
Class A and Class B shares	14	**519.1**	514.3
Contributed surplus	15	**0.7**	0.4
Retained earnings		**1,721.9**	1,603.4
Foreign currency translation adjustment		**(18.2)**	(0.4)
		2,223.5	2,117.7
		$6,815.7	$6,617.5

N.C. Southern

N.C. SOUTHERN
DIRECTOR

B.K. French

B.K. FRENCH
DIRECTOR

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

	Note	Three Months Ended December 31 2005	2004	Year Ended December 31 2005	2004
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 89.1**	$ 90.3	**$ 265.6**	$ 309.0
Adjustments for:					
Depreciation and amortization		**84.5**	81.2	**311.5**	291.5
Future income taxes		**0.6**	(16.0)	**7.7**	(18.5)
Gain on transfer of retail energy supply businesses - net of income taxes	3	**-**	-	**-**	(55.1)
Deferred availability incentives		**14.5**	8.1	**13.7**	2.8
TXU Europe settlement - net of income taxes	5	**(3.7)**	-	**45.8**	-
Other		**2.8**	0.8	**15.0**	8.6
Cash flow from operations		**187.8**	164.4	**659.3**	538.3
Changes in non-cash working capital	16	**(1.2)**	(31.0)	**90.2**	102.3
		186.6	133.4	**749.5**	640.6
Investing activities					
Purchase of property, plant and equipment		**(181.2)**	(149.1)	**(526.7)**	(535.5)
Proceeds on transfer of retail energy supply businesses - net of income taxes	3	**-**	-	**43.4**	22.5
Costs on disposal of property, plant and equipment		**(4.4)**	(0.7)	**(5.9)**	(2.6)
Contributions by utility customers for extensions to plant		**6.7**	10.3	**44.1**	50.9
Non-current deferred electricity costs		**(5.7)**	4.0	**(15.7)**	(5.9)
Changes in non-cash working capital	16	**24.4**	8.3	**(3.4)**	3.4
Other		**(0.1)**	2.0	**(6.2)**	(2.1)
		(160.3)	(125.2)	**(470.4)**	(469.3)
Financing activities					
Change in notes payable		**-**	(96.0)	**-**	-
Issue of long term debt		**185.0**	300.0	**222.0**	539.8
Issue of non-recourse long term debt		**-**	-	**-**	10.0
Repayment of long term debt		**(35.4)**	(36.8)	**(167.1)**	(168.6)
Repayment of non-recourse long term debt		**(9.1)**	(8.8)	**(54.3)**	(49.2)
Issue (purchase) of Class A shares		**(2.7)**	0.2	**(2.7)**	(3.0)
Dividends paid to Class A and Class B share owners		**(34.9)**	(33.6)	**(139.6)**	(134.4)
Income tax reassessment		**-**	12.9	**-**	12.9
Changes in non-cash working capital	16	**0.3**	(1.9)	**3.1**	(1.8)
Other		**(2.1)**	(5.3)	**(3.2)**	(6.3)
		101.1	130.7	**(141.8)**	199.4
Foreign currency translation		**0.2**	(0.1)	**(11.2)**	(0.5)
Cash position [1]					
Increase		**127.6**	138.8	**126.1**	370.2
Beginning of period		**696.8**	559.5	**698.3**	328.1
End of period		**$ 824.4**	$ 698.3	**$ 824.4**	$ 698.3

[1] Cash position includes cash and short term investments less current bank indebtedness.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2005

(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.

Effective January 1, 2005, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants ("CICA") guideline pertaining to the consolidation of variable interest entities. The guideline requires the Corporation to identify variable interest entities in which it has an interest, determine whether it is the primary beneficiary of such entities, and, if so, to consolidate them. This change in accounting had no effect on the consolidated financial statements for the three months and year ended December 31, 2005.

Effective January 1, 2005, the Corporation prospectively adopted the CICA guideline pertaining to lease arrangements. The guideline requires the Corporation to identify arrangements that do not take the legal form of a lease but convey a right to use a tangible asset in return for a payment or series of payments, and, if so, to account for them as leases. This change in accounting had no effect on the consolidated financial statements for the year ended December 31, 2005.

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".

Effective December 31, 2005, the Corporation retroactively adopted the CICA guideline pertaining to the disclosure and presentation of information by entities subject to rate regulation. This guideline no longer permitted the netting of accrued and regulatory pension and other post employment benefits assets and liabilities, with the result that the Corporation's total assets and liabilities reported in 2004 increased by $154.4 million. This change in presentation had no effect on the Corporation's earnings and earnings per share or cash flows. 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.

1. Summary of significant accounting policies (continued)

Revenue Recognition

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

Prior to the transfer of retail energy supply businesses (see Note 3), revenues from regulated sales of natural gas and electricity by ATCO Gas and ATCO Electric were recognized upon delivery, primarily on the basis of meter readings, and included an estimate of usage not yet billed.

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.

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 includes purchases of natural gas for regulated operations (see Note 3 regarding the transfer of retail energy supply businesses) and other subsidiaries. Natural gas supply expense for other subsidiaries consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties.

Prior to the transfer of retail energy supply businesses (see Note 3), natural gas supply expense for the regulated operations was based on the forecast cost of natural gas included in customer rates. Variances from forecast costs were deferred until such time as approval from the Alberta Energy and Utilities Board ("AEUB") was obtained for refund to or collection from customers and revenues and natural gas supply expense were adjusted accordingly.

Subsequent to the transfer of retail energy supply businesses, natural gas supply expense for the regulated operations is based on actual costs incurred.

1. **Summary of significant accounting policies** (continued)

Purchased Power

Prior to the transfer of retail energy supply businesses (see Note 3), purchased power expense in ATCO Electric was based on the actual cost of electricity purchased, whereas the amount included in customer rates was based on forecast cost. Revenues were adjusted for variances from forecast cost, and the variances were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers.

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.

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the 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.

An impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses 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.

1. **Summary of significant accounting policies** (continued)

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.

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.

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.

1. Summary of significant accounting policies (continued)

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.

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 other assets.

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.

1. **Summary of significant accounting policies** (continued)

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 expiry of the PPA's. 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 appropriate 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.

2. Accounting for rate regulated operations (continued)

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, 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.

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:

	2005	2004
Regulatory assets – current:		
Deferred hearing costs	**$ 8.8**	$ -
Other regulatory assets	**10.3**	5.4
	19.1	5.4
Regulatory assets – non-current:		
Regulatory other post employment benefits asset (Note 19)	**22.0**	16.8
Deferred electricity costs	**5.4**	-
Deferred hearing costs	**1.6**	4.9
Reserves for injuries and damages	**5.4**	7.6
Other regulatory assets	**0.6**	1.1
	35.0	30.4
	$ 54.1	$ 35.8
Regulatory liabilities – current:		
Deferred electricity cost recoveries	**$ 4.0**	$ 11.7
Deferred natural gas cost recoveries	**-**	0.9
Reserves for injuries and damages	**0.8**	-
Other regulatory liabilities	**1.6**	1.0
	6.4	13.6
Regulatory liabilities – non-current:		
Regulatory pension liability (Note 19)	**139.4**	137.6
Deferred royalty credits	**18.1**	14.1
Deferred electricity cost recoveries	**-**	10.3
Deferred hearing costs	**2.6**	1.9
Reserves for injuries and damages	**0.8**	1.7
Other regulatory liabilities	**1.0**	-
	161.9	165.6
	$168.3	$179.2

2. Accounting for rate regulated operations (continued)

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 2005 would have been $1.6 million lower (2004 – $10.2 million lower), and other post employment benefit plan cost in 2005 would have been $3.3 million higher (2004 – $2.5 million higher), in the absence of rate regulation.

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 2005 would have been $23.4 million lower (2004 – $4.8 million higher) 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 2005 would have been $4.0 million higher (2004 – $5.8 million lower) 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 2005 would have been $1.1 million lower (2004 – $2.5 million higher) in the absence of rate regulation.

2. Accounting for rate regulated operations (continued)

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 2005 would have been $1.0 million lower (2004 – $1.0 million lower) in the absence of rate regulation.

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 2005 would have been $4.0 million lower (2004 – $3.8 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 (see transfer of retail energy supply businesses in Note 3) and associated late payment charges net of bad debt recoveries of $1.4 million (2004 – $2.6 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 of $1.0 million (2004 – $1.1 million); and,
   iii) Removal and abandonment costs related to previously disposed of production properties of $5.0 million (2004 – $1.6 million).

   GAAP requires that these costs be expensed in the period in which they are incurred. Consequently, expenses in 2005 would have been $2.1 million higher (2004 – $4.5 million higher) in the absence of rate regulation. With the exception of $0.5 million of deferred Utilities Consumer Advocate costs which are deferred in non-current regulatory assets in the balance sheet, these assets are included in current regulatory assets and are recoverable from customers in 2006.

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 renders 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. ATCO Gas is now required to submit a filing to the AEUB to approve the allocation of the net proceeds. The net proceeds of the sale remain in trust pending AEUB approval. GAAP requires that gains and losses related to asset dispositions be recognized in the period the disposition was made. Consequently, revenues in 2005 would have been $1.0 million higher in the absence of rate regulation. This liability is included in non-current regulatory liabilities in the balance sheet.

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 2005 would have been $0.1 million lower (2004 – $12.6 million lower) and expenses would have been $1.6 million lower (2004 – $6.8 million lower) in the absence of rate regulation. On the balance sheet, assets of $2.2 million (2004 – $0.1 million) are included in current regulatory assets, and liabilities of $1.6 million (2004 – $1.0 million) are included in current regulatory liabilities.

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 2005 would have been \$1.2 million lower (2004 – nil) in the absence of rate regulation. Assets of \$1.2 million (2004 – nil) 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. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the transfer of the retail energy supply businesses, resulted in a gain of \$63.3 million before income taxes of \$8.2 million and increased 2004 earnings by \$55.1 million.

The Corporation's revenues and natural gas supply and purchased power costs after May 4, 2004 were reduced accordingly for 2004 and thereafter. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEML until the transfer of the relevant ATCO Gas natural gas purchase contracts to DEML was completed in September 2004. There will be no ongoing impact on earnings resulting from the transfer of these businesses as natural gas and electricity have historically been sold to customers on a "no-margin" basis. 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 terminates ATCO Pipelines' obligation to purchase natural gas for sale to customers effective October 31, 2005.

Under the various transaction agreements, ATCO Gas and ATCO Electric have transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions ("the transferred functions").

3. Transfer of retail energy supply businesses (continued)

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AEUB to do so), the agreements will terminate and 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. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below $200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and ATCO Electric.

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

4. Regulatory matters

In May 2005, ATCO Electric filed a general tariff application with the AEUB for the 2005 and 2006 test years requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. A decision from the AEUB on the general tariff application is not expected until March 2006. In May and June 2005, ATCO Electric filed applications requesting interim refundable rates for distribution and transmission operations, pending the AEUB's decision on the general tariff application. On July 14, 2005, ATCO Electric received a decision from the AEUB approving its requested interim refundable rates for distribution operations. On September 7, 2005, ATCO Electric received a decision from the AEUB approving an interim refundable rate increase of $5.0 million for transmission operations. Revenues associated with these interim refundable rates were recorded 2005.

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. In May 2005, ATCO Gas submitted a general rate application with the AEUB for the 2005, 2006 and 2007 test years. In August 2005, the AEUB approved interim refundable rates which recognized only 28% of the increased operating costs and rate base additions requested in the original application. On January 27, 2006, ATCO Gas received an AEUB decision which did not materially change the earnings based on the 2005 interim rates. The final impact of the decision will not be known until two subsequent regulatory processes are finalized.

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 has now been reached with respect to Barking Power's claim.

On March 30, 2005, the Corporation announced that Barking Power will receive £179.3 million (approximately $410 million) in settlement of its claim, of which the Corporation's share is approximately $104 million. Barking Power received a first distribution of £112.3 million (approximately $257 million) on March 30, 2005, of which the Corporation's share was $65.4 million. Income taxes of approximately $17.7 million relating to this distribution have been paid. A second distribution of £32.2 million (approximately $69.6 million) was received on

5. TXU Europe settlement (continued)

August 2, 2005, of which the Corporation's share was $17.7 million, and a third distribution of £31.8 million (approximately $65.2 million) was received on January 19, 2006, of which the Corporation's share was $16.6 million. Income taxes of approximately $10.3 million relating to the second and third distributions will be paid as part of the Corporation's normal tax installments. A final distribution is expected in the second quarter of 2006.

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

	2005	2004
Interest	**$29.0**	$22.0
Allowance for funds used by regulated operations	**7.0**	6.2
Other	**0.6**	2.6
	$36.6	$30.8

7. Income taxes

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

	2005		2004	
Earnings before income taxes	**$477.0**	%	$502.8	%
Income taxes, at statutory rates	**$193.8**	**40.6**	$205.5	40.9
Federal general tax reduction [1]	**(18.1)**	**(3.8)**	(18.4)	(3.7)
Manufacturing and processing tax credit	**(7.5)**	**(1.6)**	(7.7)	(1.6)
Resource allowance	**(2.8)**	**(0.6)**	(3.3)	(0.7)
Crown royalties and other non-deductible Crown payments	**1.1**	**0.2**	0.7	0.1
Large Corporations Tax	**7.8**	**1.7**	7.8	1.6
Foreign tax rate variance	**(6.2)**	**(1.3)**	(4.6)	(0.9)
Non-deductible interest on foreign financing	**1.4**	**0.3**	1.8	0.4
Unrecorded future income taxes relating to regulated operations	**1.0**	**0.2**	4.4	0.9
Transfer of retail energy supply businesses	**-**	**-**	(12.1)	(2.4)
Change in future income taxes resulting from reduction in tax rates	**-**	**-**	(2.6)	(0.5)
Change in method of accounting for future income taxes in certain regulated operations	**-**	**-**	(15.8)	(3.1)
Other	**5.1**	**1.1**	2.3	0.4
	175.6	**36.8**	158.0	31.4
Current income taxes	**185.8**		187.6	
Future income taxes (recoveries)	**$ (10.2)**		$ (29.6)	

(1) The federal general tax reduction of 7% (2004 — 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 3% (2004 – 2%) is applicable to earnings that have benefited from the resource allowance.

7. **Income taxes** (continued)

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

	2005	2004
Property, plant and equipment	**$222.7**	$216.7
Deferred assets and liabilities	**(18.3)**	5.5
Tax loss carryforwards	**(0.3)**	(0.9)
Other	**0.3**	0.8
	204.4	222.1
Less: Amounts included in current future income taxes	**4.1**	(0.3)
	$200.3	$222.4

Unrecorded future income tax liabilities of the regulated operations amounted to $171.3 million at December 31, 2005. This balance includes $28.2 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

Expected future recoveries relating to tax loss carryforwards have been recorded in the amount of $0.3 million, of which $0.1 million begins to expire in 2009 and $0.2 million does not expire. In addition, there are tax loss carryforwards of $0.7 million for which no tax benefit has been recorded. These losses begin to expire in 2010.

Income taxes paid amounted to $178.6 million (2004 – $134.5 million).

8. **Property, plant and equipment**

		2005		2004	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	3.6%	**$6,022.0**	**$2,240.8**	$5,593.1	$2,082.1
Power Generation	3.3%	**2,753.9**	**921.4**	2,770.5	849.6
Global Enterprises	8.8%	**270.3**	**127.1**	253.5	119.3
Other	5.0%	**27.7**	**6.1**	27.0	4.7
		$9,073.9	**3,295.4**	$8,644.1	3,055.7
Property, plant and equipment less accumulated depreciation			**5,778.5**		5,588.4
Unamortized contributions by utility customers for extensions to plant			**569.8**		545.9
			$5,208.7		$5,042.5

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $323.6 million (2004 – $297.9 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $91.1 million (2004 – $75.7 million) and non-depreciable assets of $41.3 million (2004 – $40.4 million).

9. Other assets

	2005	2004
Accrued pension asset (Note 19)	**$192.2**	$193.5
Security deposits for debt	**20.0**	23.1
Deferred financing charges [(2)]	**25.4**	27.6
Other [(1)]	**31.5**	30.4
	$269.1	$274.6

(1) Amortization of certain other assets, which was recorded in depreciation and amortization, amounted to $5.9 million (2004 – $12.2 million).

(2) Amortization of deferred financing charges, which was recorded in interest expense, amounted to $2.8 million (2004 – $3.1 million).

10. Bank indebtedness and credit lines

At December 31, 2005, bank indebtedness consists of $0.2 million (2004 — $1.2 million), at an interest rate of 5.0%, repayable on demand.

At December 31, 2005, the Corporation has the following credit lines that enable it to obtain financing for general business purposes:

	2005			2004		
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$326.0**	**$11.9**	**$314.1**	$ 326.0	$12.0	$314.0
Short term committed	**600.0**	**-**	**600.0**	614.1	22.3	591.8
Uncommitted	**69.1**	**8.3**	**60.8**	69.0	11.4	57.6
	$995.1	**$20.2**	**$974.9**	$1,009.1	$45.7	$963.4

Of the $20.2 million used at December 31, 2005, $11.5 million is included in long term debt, $0.2 million is included in bank indebtedness and $8.5 million represents outstanding letters of credit.

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

Long term debt

	2005	2004
CU Inc. debentures – unsecured		
1995 Series 8.43% due June 2005	**$ -**	$ 125.0
2001 4.84% due November 2006	**175.0**	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
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**	-
Canadian Utilities Limited debentures – unsecured		
2002 6.14% due November 2012	**100.0**	100.0
	2,215.0	2,155.0
ATCO Power Australia Pty Ltd. credit facility, at Bank Bill rates, payable in Australian dollars, unsecured (1)	**-**	5.3
ATCO Power Canada Ltd. credit facility, at BA rates, due March 2007, secured by a pledge of cash (1)	**11.5**	11.5
Other long term obligation, at 5.0%, due June 2007, unsecured	**4.5**	4.5
	2,231.0	2,176.3
Less: Amounts due within one year	**-**	5.3
	$2,231.0	$2,171.0

Non-recourse long term debt

	2005	2004
Barking Power Limited project financing, payable in British pounds:		
At fixed rates averaging 7.95%, due to 2010	**$ 54.7**	$ 72.2
At LIBOR, due to 2010 (1)	**89.6**	118.4
Osborne Cogeneration Pty Ltd. project financing, payable in Australian dollars:		
At Bank Bill rates, due to 2013 (1)	**1.8**	2.3
At 7.3325%, due to 2013 (1)	**34.4**	42.6
ATCO Power Alberta Limited Partnership ("APALP") project financing:		
At 7.54% to 2008, at LIBOR thereafter, due to 2016 (1)	**3.8**	5.1
At 7.317% to 2008, at LIBOR thereafter, due to 2016 (1)	**5.4**	8.1
At 7.50% to 2011, at LIBOR thereafter, due to 2016 (1)	**87.5**	89.7
Joffre project financing:		
At 7.286%, due to 2012 (1)	**26.7**	31.9
At 8.59%, due to 2020	**32.0**	32.0

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

Non-recourse long term debt (continued)

	2005	2004
Scotford project financing:		
At 5.202%, due to 2008, at BA rates thereafter, due to 2014 (1)	**46.2**	50.4
At 5.202%, due to 2008, at LIBOR thereafter, due to 2014 (1)	**11.6**	12.6
At 7.93%, due to 2022	**26.9**	27.6
Muskeg River project financing:		
At 5.247%, due 2007, at BA rates thereafter, due to 2014 (1)	**44.4**	47.8
At BA rates, due to 2014 (1)	**0.3**	0.4
At 7.56%, due to 2022	**31.2**	33.1
Brighton Beach project financing:		
At 5.8367%, due 2009, at BA or Canadian Eurodollar rates thereafter, due to 2019 (1)	**9.4**	9.8
At BA or Canadian Eurodollar rates, due to 2019 (1)	**2.5**	1.3
At 6.575%, due to 2019 (1)	**37.8**	39.5
At 6.924%, due to 2024	**110.5**	110.6
Cory project financing:		
At BA rates, due to 2011 (1)	**0.3**	0.3
At 6.336%, due to 2011 (1)	**3.3**	3.9
At 7.586%, due to 2025	**37.4**	38.2
At 7.601%, due to 2026	**33.1**	33.7
	730.8	811.5
Less: Amounts due within one year	**57.0**	50.6
	$673.8	$760.9

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% (2004 — 1.1%) (Note 20).

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 96% (2004 — 95%) 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, 2005 was $1,342.4 million (2004 — $1,342.5 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) **Equity contributions** – Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2005, there are no further obligations under this guarantee for the Brighton Beach project financing.

b) **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.

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

The maximum amount of the indemnity is $20 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.

c) **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, 2005, no amounts were outstanding under the guarantee.

d) **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, 2005, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil (1)	$13.6
Brighton Beach project financing	Nil (2)	Nil
Cory project financing	Nil (1)	Nil
Joffre project financing	Nil (3)	$ 4.3
Muskeg River project financing	Nil (1)	$ 5.1
Scotford project financing	Nil (1)	$ 5.6

(1) No major maintenance reserve required for this financing.
(2) Reserve requirements of $3.4 million met with project cash flows.
(3) Reserve requirements of $0.7 million met with project cash flows.

e) **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, 2005, the maximum value of the guarantee is $31.2 million.

f) **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

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

(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.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2005, 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
2006	$175.0	$ 57.0	$232.0
2007	66.0	51.7	117.7
2008	100.0	76.2	176.2
2009	125.0	70.3	195.3
2010	125.0	76.9	201.9
	$591.0	$332.1	$923.1

Of the $232.0 million due in 2006, $175.0 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest on debt is as follows:

	2005	2004
Long term debt	**$154.5**	$148.3
Non-recourse long term debt	**51.4**	55.6
Notes payable	**-**	0.7
Bank indebtedness	**1.3**	1.8
Amortization of deferred financing charges	**2.8**	3.1
Less: Capitalized on non-regulated projects	**-**	(5.8)
	$210.0	$203.7

Interest paid amounted to $207.2 million (2004 – $201.2 million).

11. 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.

	2005	2004
Long term debt		
Fixed rate	**$2,656.2**	$2,536.6
Floating rate	**11.5**	16.8
	$2,667.7	$2,553.4
Non-recourse long term debt		
Fixed rate	**$ 683.9**	$ 735.3
Floating rate	**94.5**	122.8
	$ 778.4	$ 858.1

12. Deferred credits

	2005	2004
Accrued other post employment benefits liability (Note 19)	**$ 35.4**	$ 27.7
Deferred revenues (Note 5)	**59.6**	6.4
Deferred availability incentives	**59.7**	46.1
Asset retirement obligations	**62.2**	34.7
Accrued equipment repairs and maintenance	**8.8**	10.1
Other	**28.1**	21.8
	$253.8	$146.8

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $8.9 million (2004 – $7.6 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:

	2005	2004
Obligations at beginning of year	**$34.7**	$32.3
Obligations incurred	**25.4**	0.5
Accretion expense	**2.1**	1.9
Obligations at end of year	**$62.2**	$34.7

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $125 million, which will be incurred between 2006 and 2052. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.6%.

13. Equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	2005 Shares	2005 Amount	2004 Shares	2004 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						
5.05% Series O	$25.00	December 2, 2006	**1,600,000**	**40.0**	1,600,000	40.0
5.05% Series T	$25.00	December 2, 2006	**1,600,000**	**40.0**	1,600,000	40.0
5.05% Series U	$25.00	December 2, 2006	**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 $669.1 million (2004 – $669.2 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.

14. Class A and Class B shares

In July 2005, the Corporation's board of directors approved a two-for-one share split of the outstanding Class A non-voting and Class B common shares. The share split took the form of a stock dividend whereby share owners received one additional Class A non-voting share for each Class A non-voting share held as of the record date and one additional Class B common share for each Class B common share held as of the record date. The stock dividend was paid on September 15, 2005 to share owners of record at the close of business on August 29, 2005. All share, stock option and per share amounts have been retroactively restated to reflect this share split.

14. Class A and Class B shares (continued)

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, 2003	82,267,418	$369.6	44,499,852	$140.9	126,767,270	$510.5
Purchased	(290,800)	(1.3)	-	-	(290,800)	(1.3)
Stock options exercised	306,600	5.1	-	-	306,600	5.1
Converted: Class B to Class A	457,368	1.4	(457,368)	(1.4)	-	-
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**

From January 1, 2006 to February 10, 2006, 63,100 Class A non-voting shares were issued with respect to the exercises of stock options.

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	
	2005	2004	**2005**	2004
	(Unaudited)			
Weighted average shares outstanding	**126,928,689**	126,746,566	**126,901,614**	126,765,042
Effect of dilutive stock options	**685,048**	530,826	**551,357**	498,978
Weighted average diluted shares outstanding	**127,613,737**	127,277,392	**127,452,971**	127,264,020

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.

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 20,000,000 of the issued and outstanding

14. Class A and Class B shares (continued)

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, 2004, 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, 2005. Over the life of the bid, 289,800 shares were purchased, of which 256,800 were purchased in 2004 and 33,000 were purchased in 2005. 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 will expire on May 19, 2006. From May 20, 2005, to February 10, 2006, 195,600 shares have been purchased, all of which were purchased in 2005.

15. 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, 2,747,200 Class A non-voting shares are available for issuance at December 31, 2005. 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:

	2005		2004	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**1,555,600**	**$19.45**	1,888,900	$18.94
Granted	**204,000**	**30.50**	6,000	26.45
Exercised	**(338,000)**	**17.07**	(306,600)	16.33
Cancelled	**(6,100)**	**24.93**	(32,700)	20.57
Options at end of year	**1,415,500**	**$21.59**	1,555,600	$19.45

Information about stock options outstanding at December 31, 2005 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$13.06 - $18.87	600,900	2.7	$16.57	600,900	$16.57
$20.65 - $28.65	610,600	4.3	23.54	529,800	23.19
$30.25 - $43.49	204,000	9.0	30.50	-	-
$13.06 - $43.49	1,415,500	4.3	$21.59	1,130,700	$19.67

In 2005, Canadian Utilities Limited granted 204,000 options to purchase Class A non-voting shares to officers and certain key employees at a weighted average exercise price of $30.50 per share. The options have a term of ten years and vest over the first five years.

On January 2, 2006, Canadian Utilities Limited granted 119,000 options to purchase Class A non-voting shares to officers and certain key employees at a weighted average exercise price of $43.56 per share. The options have a term of ten years and vest over the first five years.

15. Stock based compensation plans (continued)

Changes in contributed surplus are summarized below:

	2005	2004
Contributed surplus at beginning of year	**$ 0.4**	$ 0.3
Stock option expense	**0.3**	0.1
Contributed surplus at end of year	**$ 0.7**	$ 0.4

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2005 at $3.21 per option (2004 – $2.84 per option) using the following weighted average assumptions:

	2005	2004
Risk free interest rate	**4.0%**	4.2%
Expected holding period prior to exercise	**6.3 years**	6.5 years
Share price volatility	**11.7%**	12.7%
Estimated annual Class A share dividend	**3.5%**	4.0%

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 $9.0 million (2004 – $0.9 million).

16. Changes in non-cash working capital

	2005	2004
Operating activities, changes related to:		
Accounts receivable	**$ (6.7)**	$ 217.9
Inventories	**85.3**	(1.3)
Regulatory assets	**(1.4)**	23.3
Prepaid expenses	**(1.7)**	5.3
Accounts payable and accrued liabilities	**29.3**	(188.2)
Income taxes	**(12.0)**	41.8
Future income taxes	**5.3**	(9.0)
Regulatory liabilities	**(7.9)**	12.5
	$ 90.2	$ 102.3
Investing activities, changes related to:		
Inventories	**$ (1.5)**	$ (0.2)
Prepaid expenses	**0.1**	(0.1)
Accounts payable and accrued liabilities	**9.0**	(4.5)
Income taxes	**(11.0)**	11.0
Future income taxes	**-**	(2.8)
	$ (3.4)	$ 3.4
Financing activities, changes related to:		
Accounts receivable	**$ 3.1**	$ (1.8)

17. Joint ventures

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

	2005	2004
Statement of earnings		
Revenues	**$ 528.6**	$ 452.6
Operating expenses	**355.1**	311.5
Depreciation and amortization	**43.1**	39.2
Interest	**41.5**	39.3
	88.9	62.6
Interest and other income	**7.7**	6.8
Earnings from joint ventures before income taxes	**$ 96.6**	$ 69.4
Balance sheet		
Current assets	**$ 247.4**	$ 148.9
Current liabilities	**(159.6)**	(122.2)
Property, plant and equipment	**922.3**	990.0
Deferred items – net	**(101.3)**	(68.0)
Non-recourse long term debt	**(504.2)**	(579.6)
Investment in joint ventures	**$ 404.6**	$ 369.1
Statement of cash flows		
Operating activities	**$ 175.4**	$ 91.1
Investing activities	**(16.0)**	(46.6)
Financing activities	**(79.1)**	(50.1)
Foreign currency translation	**(9.5)**	(0.4)
Increase (decrease) in cash position	**$ 70.8**	$ (6.0)

Current assets include cash of $118.6 million (2004 — $48.7 million) which is only available for use within the joint ventures (see Note 5).

18. Related party transactions

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $2.5 million (2004 — $1.8 million), provided computer operations and systems development services totaling $5.0 million (2004 – $0.4 million), recovered administrative expenses totaling $2.4 million (2004 — $2.3 million) and incurred administrative expenses and corporate signature rights totaling $7.1 million (2004 — $7.1 million). The Corporation also incurred advertising and promotion expenses from an entity related through common control totaling $1.4 million (2004 — $1.1 million).

At December 31, 2005, accounts receivable due from related parties amounted to $1.8 million (2004 – $0.8 million) and accounts payable due to related parties amounted to $0.5 million (2004 – $0.4 million).

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

19. 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.

19. **Employee future benefits** (continued)

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

	2005		2004	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,402.1**	**$ -**	$1,322.5	$ -
Actual return on plan assets	**197.0**	**-**	115.8	-
Employee contributions	**4.0**	**-**	5.0	-
Benefit payments	**(36.4)**	**-**	(36.1)	-
Payments to defined contribution plan	**(5.6)**	**-**	(5.1)	-
End of year	**$1,561.1**	**$ -**	$1,402.1	$ -
Accrued benefit obligations:				
Beginning of year	**$1,232.7**	**$ 67.0**	$1,092.6	$ 62.5
Current service cost	**32.2**	**2.5**	23.6	2.0
Interest cost	**73.9**	**4.2**	69.5	3.8
Employee contributions	**4.0**	**-**	5.0	-
Benefit payments from plan assets (1)	**(36.4)**	**-**	(36.1)	-
Benefit payments by employer	**(4.7)**	**(1.9)**	(4.1)	(2.0)
Experience losses (2)	**183.3**	**8.5**	82.2	0.7
End of year	**$1,485.0**	**$ 80.3**	$1,232.7	$ 67.0
Funded status:				
Excess (deficiency) of assets over obligations	**$ 76.1**	**$(80.3)**	$ 169.4	$(67.0)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**369.5**	**21.9**	310.3	14.0
Unrecognized net transitional liability (asset)	**(253.4)**	**23.0**	(286.2)	25.3
Accrued asset (liability) (Notes 9, 12)	**$ 192.2**	**$(35.4)**	$ 193.5	$(27.7)
Regulatory asset (liability) (3) (Note 2)	**$ (139.4)**	**$ 22.0**	$ (137.6)	$ 16.8

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

(2) A change in the liability discount rate assumption resulted in experience losses in 2005 of approximately $178 million for the pension benefit plans.

(3) 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.

19. **Employee future benefits** (continued)

	2005		2004	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost (income)				
Components of benefit plan cost (income):				
Current service cost	**$ 32.2**	**$ 2.5**	$ 23.6	$ 2.0
Interest cost	**73.9**	**4.2**	69.5	3.8
Actual return on plan assets	**(197.0)**	**-**	(115.8)	-
Experience losses on accrued benefit obligations	**183.3**	**8.5**	82.2	0.7
	92.4	**15.2**	59.5	6.5
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**108.5**	**-**	29.4	-
Unrecognized portion of experience losses on accrued benefit obligations	**(183.3)**	**(8.5)**	(82.2)	(0.7)
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**15.5**	**0.6**	12.7	0.3
Amortization of net transitional liability (asset)	**(32.8)**	**2.3**	(32.8)	2.3
	(92.1)	**(5.6)**	(72.9)	1.9
Defined benefit plans cost (income)	**0.3**	**9.6**	(13.4)	8.4
Defined contribution plans cost	**7.0**	**-**	6.4	-
Total cost (income)	**7.3**	**9.6**	(7.0)	8.4
Less: Capitalized	**1.4**	**2.3**	1.2	2.0
Less: Unrecognized defined benefit plans cost (income) [1]	**(1.6)**	**3.3**	(10.2)	2.5
Net cost recognized	**$ 7.5**	**$ 4.0**	$ 2.0	$ 3.9

[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.

In the unaudited three months ended December 31, 2005, net cost of $1.7 million (2004 – $0.6 million) was recognized for pension benefit plans and net cost of $0.6 million (2004 – $1.0 million) was recognized for other post employment benefit plans.

19. Employee future benefits (continued)

Weighted average assumptions

	2005		2004	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost (income):				
Expected long term rate of return on plan assets for the year	**6.9%**	**-**	7.25%	-
Liability discount rate for the year	**5.9%**	**5.9%**	6.25%	6.25%
Average compensation increase for the year	**3.25%**	**-**	3.0%	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**5.1%**	**5.1%**	5.9%	5.9%
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, 9.3% for 2005 grading down over 8 years to 4.5% (2004 – 9.9% for 2004 grading down over 9 years to 4.5%), and, for other medical and dental costs, 4.0% for 2005 and thereafter (2004 – 4.0% for 2004 and thereafter).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2005 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.

	2005 Pension Benefit Plans		2005 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost (Income)	Accrued Benefit Obligation	Benefit Plan Cost (Income)
Expected long term rate of return on plan assets				
1% increase [1]	-	$(3.2)	-	-
1% decrease [1]	-	$ 3.2	-	-
Liability discount rate				
1% increase [1]	$(57.7)	$(4.9)	$(3.3)	$(0.3)
1% decrease [1]	$ 74.0	$ 6.3	$ 4.1	$ 0.4
Future compensation rate				
1% increase [1]	$ 18.1	$ 2.5	-	-
1% decrease [1]	$(15.6)	$(2.1)	-	-
Long term inflation rate				
1% increase [1] [2] [3]	$ 25.0	$ 3.2	$ 3.7	$ 0.6
1% decrease [1] [3]	$(42.7)	$(5.2)	$(3.0)	$(0.5)

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost (income), 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.

19. Employee future benefits (continued)

Pension benefit plan assets

	2005		2004	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [1]	**$ 922.9**	**59.1**	$ 809.2	57.7
Fixed income securities [2]	**567.7**	**36.4**	507.2	36.2
Real estate [3]	**31.1**	**2.0**	34.4	2.4
Cash and other assets [4]	**39.4**	**2.5**	51.3	3.7
	$1,561.1	**100.0**	$1,402.1	100.0

(1) Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2005 the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $144.0 million and $174.0 million, respectively (2004 – $134.4 million and $151.6 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, 2005, plan assets include long term debt of CU Inc. having a market value of $6.0 million (2004 – $5.3 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $17.6 million (2004 – $12.4 million) and Class I Non-Voting shares of ATCO Ltd. having a market value of $14.8 million (2004 – $10.6 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 $77.4 million at December 31, 2005 (2004 – $71.5 million).

20. 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.

20. 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 2005	2004
5.247%	90 day BA	December 2007	**$ 44.4**	$ 47.8
5.202%	90 day BA	September 2008	**59.2**	63.7
7.54%	90 day BA	November 2008	**3.8**	5.1
7.317%	90 day BA	December 2008	**5.4**	8.1
5.8367%	90 day BA	June 2009	**9.4**	9.8
6.336%	90 day BA	June 2011	**3.3**	3.9
7.50%	6 month LIBOR	December 2011	**87.5**	90.6
7.286%	90 day BA	September 2012	**28.2**	32.5
7.3325%	Bank Bill Rate in Australia	December 2013	**34.4**	42.6
6.575%	90 day BA	March 2019	**37.8**	39.5
			$313.4	$343.6

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above swap fixed interest rates include any long term debt margin fees (Note 11).

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, 2005, the contracts consist of purchases of $2.6 million U.S. (2004 — nil) and sales of 2.0 million Euros (2004 – nil).

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.

ATCO Gas has leased the entire storage capacity of the Carbon facility to ATCO Midstream for the period April 1, 2005 to March 31, 2006. At December 31, 2005, there were no contracts outstanding for natural gas sales (2004 — 12,802 terajoules ("TJ") for $76.3 million) or natural gas purchases (2004 — 107 TJ for $0.6 million).

20. 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.

	2005			2004		
	Notional Principal	**Fair Value (Payable) Receivable**	**Maturity**	Notional Principal	Fair Value (Payable) Receivable	Maturity
Interest rate swaps	**$313.4**	**$(10.5)**	**2007-2019**	$343.6	$(16.0)	2007-2019
Foreign exchange forward contracts	**$ 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.

21. Commitments and contingencies

Commitments

The Corporation has contractual obligations in the normal course of business, including long term operating leases for office premises and equipment. Future minimum lease payments are as follows:

2006	2007	2008	2009	2010	Total of All Subsequent Years
$15.9	$14.4	$13.2	$6.7	$6.0	$7.0

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

The Government of Canada has 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 without merit 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.

22. 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 and the regulated supply of electricity by Alberta Power (2000).

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, the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel.

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

Segmented results – Three months ended December 31

2005 2004	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$299.1**	**$208.2**	**$172.7**	**$ 0.3**	**$ -**	**$680.3**
	$293.8	$183.9	$158.9	$ 0.4	$ -	$637.0
Revenues – intersegment [1]	**6.4**	**-**	**30.0**	**2.9**	**(39.3)**	**-**
	4.1	-	29.3	3.5	(36.9)	-
Revenues	**$305.5**	**$208.2**	**$202.7**	**$ 3.2**	**$(39.3)**	**$680.3**
	$297.9	$183.9	$188.2	$ 3.9	$(36.9)	$637.0
Earnings attributable to Class A and Class B shares	**$ 32.5**	**$ 36.1**	**$ 28.2**	**$(7.5)**	**$ (0.2)**	**$ 89.1**
	$ 38.5	$ 24.1	$ 30.8	$(3.6)	$ 0.5	$ 90.3

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

22. Segmented information (continued)

Segmented results – Year ended December 31

2005 2004	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,173.5** $1,771.6	**$ 761.7** $ 653.2	**$579.4** $585.4	**$ 1.2** $ 1.2	**$ -** $ -	**$2,515.8** $3,011.4
Revenues – intersegment [1]	**22.4** 18.2	**-** -	**108.6** 334.7	**11.2** 10.4	**(142.2)** (363.3)	**-** -
Revenues	**1,195.9** 1,789.8	**761.7** 653.2	**688.0** 920.1	**12.4** 11.6	**(142.2)** (363.3)	**2,515.8** 3,011.4
Operating expenses	**716.9** 1,328.6	**414.7** 346.7	**538.8** 789.1	**24.4** 11.2	**(140.9)** (368.1)	**1,553.9** 2,107.5
Depreciation and amortization	**189.3** 178.9	**95.8** 89.5	**24.8** 22.0	**1.6** 1.1	**-** -	**311.5** 291.5
Interest expense	**124.9** 118.8	**84.8** 84.5	**2.4** 2.4	**154.6** 148.0	**(156.7)** (150.0)	**210.0** 203.7
Gain on transfer of retail energy supply businesses	**-** (63.3)	**-** -	**-** -	**-** -	**-** -	**-** (63.3)
Interest and other income	**(11.8)** (8.6)	**(9.3)** (7.9)	**(2.0)** (2.4)	**(170.2)** (161.9)	**156.7** 150.0	**(36.6)** (30.8)
Earnings before income taxes	**176.6** 235.4	**175.7** 140.4	**124.0** 109.0	**2.0** 13.2	**(1.3)** 4.8	**477.0** 502.8
Income taxes	**60.2** 56.3	**69.1** 56.8	**43.0** 36.9	**3.7** 6.2	**(0.4)** 1.8	**175.6** 158.0
	116.4 179.1	**106.6** 83.6	**81.0** 72.1	**(1.7)** 7.0	**(0.9)** 3.0	**301.4** 344.8
Dividends on equity preferred shares	**10.4** 10.4	**3.6** 3.6	**-** -	**21.8** 21.8	**-** -	**35.8** 35.8
Earnings attributable to Class A and Class B shares	**$ 106.0** $ 168.7	**$ 103.0** $ 80.0	**$ 81.0** $ 72.1	**$(23.5)** $(14.8)	**$ (0.9)** $ 3.0	**$ 265.6** $ 309.0
Total assets	**$3,524.7** $3,422.4	**$2,216.9** $2,210.3	**$306.4** $307.8	**$614.9** $528.3	**$152.8** $148.7	**$6,815.7** $6,617.5
Purchase of property, plant and equipment	**$ 472.9** $ 426.3	**$ 41.2** $ 77.0	**$ 11.9** $ 14.5	**$ 0.7** $ 17.7	**$ -** $ -	**$ 526.7** $ 535.5

[1] Intersegment revenues are recognized on the basis of prevailing market or regulated prices.

Geographic segments

	Domestic		Foreign		Consolidated	
	2005	2004	**2005**	2004	**2005**	2004
Revenues	**$2,253.6**	$2,790.6	**$262.2**	$220.8	**$2,515.8**	$3,011.4
Property, plant and equipment	**$4,905.9**	$4,688.1	**$302.8**	$354.4	**$5,208.7**	$5,042.5

FILE NO. 82-34744

CU Release

CANADIAN UTILITIES LIMITED
An ATCO Company

CORPORATE OFFICE
1500, 909 - 11 AVENUE SW, CALGARY, ALBERTA T2R 1N6
TELEPHONE (403) 292-7500

February 22, 2006

CANADIAN UTILITIES REPORTS 2005 EARNINGS

CALGARY, Alberta – **Canadian Utilities Limited reported earnings of $265.6 million ($2.09 per share) for the year ended December 31, 2005.** This results in an increase of $11.7 million over 2004 earnings of $253.9 million ($2.00 per share) excluding the $55.1 million gain from the retail sale by ATCO Gas and ATCO Electric of their energy supply businesses to Direct Energy in 2004. Earnings for the three months ended December 31, 2005 were $89.1 million ($0.70 per share) compared to earnings for the same three months of 2004 of $90.3 million ($0.71 per share).

Financial Summary	**For the Three Months Ended December 31**		**For the Twelve Months Ended December 31**	
	2005	2004	**2005**	2004
	($ Millions except per share data) *(unaudited)*			
Earnings	**89.1**	90.3	**265.6**	309.0
Earnings excluding the retail sale gain	**89.1**	90.3	**265.6**	253.9
Earnings per Class A and B share[1]	**0.70**	0.71	**2.09**	2.44
Earnings per Class A and B share excluding retail sale gain[1]	**0.70**	0.71	**2.09**	2.00
Revenues	**680.3**	637.0	**2,515.8**	3,011.4
Cash flow from operations	**187.8**	164.4	**659.3**	538.3

[1] **Per share numbers have been retroactively restated to reflect two-for-one share split**

Earnings for the twelve months ended December 31, 2005 increased over 2004, excluding the retail sale gain, primarily due to:

- higher storage earnings due to increased storage capacity in ATCO Midstream; and
- the impact of the previously announced TXU Europe Settlement in ATCO Power.

This increase was partially offset by:

- increased share appreciation rights expense due to higher share prices;
- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream; and
- higher costs not recovered in ATCO Gas in 2005. In May 2005, ATCO Gas submitted a General Rate Application with the Alberta Energy & Utilities Board (AEUB) for the 2005, 2006 and 2007 test years. In August 2005, the AEUB approved interim refundable rates which recognized only 28% of the increased operating costs and rate base additions requested in the original application. On January 27, 2006, ATCO Gas received an AEUB decision which did not materially change the earnings based on the 2005 interim rates (the ATCO Gas Decision). The final impact of the decision will not be known until two subsequent regulatory processes are finalized. The negative impact of the ATCO Gas Decision was compounded by 7.8% warmer than normal weather.

Earnings for the three months ended December 31, 2005, decreased primarily due to:

- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream; and
- the impact of the ATCO Gas Decision.

This decrease was partially offset by:

- higher earnings in the ATCO Power's Alberta generating plants due to the higher spark spreads realized on sales in the Alberta market; and
- higher storage earnings due to increased storage capacity in ATCO Midstream.

Revenues for the twelve months ended December 31, 2005 decreased primarily due to Direct Energy assuming responsibility for selling natural gas and electricity to customers since the completion of the retail sale in the second quarter of 2004.

Revenues for the three months ended December 31, 2005 increased primarily due to:

- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices; and
- 2004 impact of 2004 General Rate Application adjustments for ATCO Gas related to the refund of deferred income taxes.

This increase was partially offset by lower availability in ATCO Power's Barking generating plant due to a planned maintenance outage in September through November 2005.

Cash flow from operations for the twelve months ended December 31, 2005 increased primarily due to higher earnings and the impact of the TXU Europe Settlement in ATCO Power.

Cash flow from operations for the three months ended December 31, 2005 increased primarily due to increased cash flow after removal of non-cash items.

On January 19, 2006, the Board of Directors of Canadian Utilities Limited declared a first quarter dividend of 28.5 cents per Class A non-voting and Class B common share, a 3.6% increase over the 27.5 cents paid in the previous quarter.

Canadian Utilities Limited's consolidated financial statements and management's discussion and analysis of financial condition and results of operations for the three and twelve months ended December 31, 2005, are now available on Canadian Utilities' website (www.canadian-utilities.com) or via SEDAR (www.sedar.com) or can be requested from the company.

The consolidated financial statements and management's discussion and analysis of financial condition and results of operations will be mailed to those share owners who have requested such information on or about March 30, 2006.

Canadian Utilities Limited is a part of the ATCO Group of companies. ATCO Group is an Alberta based, worldwide organization of companies with more than 7,000 employees actively engaged in Power Generation, Utilities and Global Enterprises. More information about Canadian Utilities can be found on its website, www.canadian-utilities.com.

For further information contact:

K.M. (Karen) Watson
Senior Vice President
& Chief Financial Officer
Canadian Utilities Limited
(403) 292-7502

FILE NO. 82-34744

Form 52-109F1 - Certification of Annual Filings

I, Karen M. Watson, Senior Vice President & Chief Financial Officer of Canadian Utilities Limited, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of **Canadian Utilities Limited** (the issuer) for the period ending December 31, 2005;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

(b) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

Date: February 22, 2006

[original signed by K.M. Watson]

____

Senior Vice President & Chief Financial Officer

Form 52-109F1 - Certification of Annual Filings

I, Nancy C. Southern, President & Chief Executive Officer of Canadian Utilities Limited, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of **Canadian Utilities Limited** (the issuer) for the period ending December 31, 2005;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared; and

(b) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation.

Date: February 22, 2006

[original signed by N.C. Southern]

President & Chief Executive Officer

FILE NO. 82-34744

ATCO
GROUP

Corporate Office

VIA SEDAR

February 22, 2006

Autorité des marches financiers
800, square Victoria, 22 étage
Tour de la Bourse
Montreal, Québec, H4Z 1G3

Re: Canadian Utilities Limited
Quebéc Securities Act - Section 52

This is Canadian Utilities Limited's report pursuant to S.114 of the Québec Securities Regulation on securities distributed in Québec under the exemptions provided by Section 52 of the *Securities Act* (Québec) (the "Act").

Please be advised that during the financial year ended December 31, 2005:

1. Canadian Utilities Limited did not distribute any securities in Québec under the exemptions provided by the Act; and

2. 4,000 options to purchase Class A Non-Voting Shares were exercised by Québec residents at an aggregate value of $57,080.00.

Yours truly,

Canadian Utilities Limited

[original signed by P. Spruin]

P. Spruin
Corporate Secretary

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED
An ATCO Company

FORM 13-502F1

ANNUAL PARTICIPATION FEE FOR REPORTING ISSUERS

For the Year Ending December 31, 2005

FORM 13-502F1
ANNUAL PARTICIPATION FEE FOR REPORTING ISSUERS

Reporting Issuer Name:		**Canadian Utilities Limited**
Participation Fee for the Financial Year Ending :		**December 31, 2005**

1. Class 1 Reporting Issuers

Market value of equity securities:

Class A Non-Voting Shares:			
Total number of securities outstanding at the end of the most recent financial year:		82,876,186	
Simple average of the closing price as of the last trading day of each of the months of the most recent financial year (1)	X	$35.69	
Market Value of Class		$2,957,851,000	$2,957,851,000 (A)
Class B Common Shares:			
Total number of securities outstanding at the end of the most recent financial year:		44,016,284	
Simple average of the closing price as of the last trading day of each of the months of the most recent financial year (1)	X	$35.69	
Market Value of Class		$1,570,941,000	$1,570,941,000 (A)

Market value of corporate debt or preferred shares of Reporting Issuer

Market value of corporate debt

6.14% Debentures		
Book Value at December 31, 2005	$100,000,000	
Market Value at December 31, 2005	$109.995	
Market Value of Class	$109,995,000	$109,995,000 (B)

Market value of preferred shares

Series Q

Total number of securities outstanding at the end of the most recent financial year:		2,277,675	
Simple average of the closing price as of the last trading day of each of the months of the most recent financial year (1)	X	$25.61	
Market Value of Class		$58,331,000	$58,331,000 (B)

Series R

Total number of securities outstanding at the end of the most recent financial year:		2,146,730	
Simple average of the closing price as of the last trading day of each of the months of the most recent financial year (1)	X	$25.15	
Market Value of Class		$53,990,000	$53,990,000 (B)

Series S

Total number of securities outstanding at the end of the most recent financial year:		635,700	
Simple average of the closing price as of the last trading day of each of the months of the most recent financial year (1)	X	$27.27	
Market Value of Class		$17,336,000	$17,336,000 (B)

Series W

Total number of securities outstanding at the end of the most recent financial year:		6,000,000	
Simple average of the closing price as of the last trading day of each of the months of the most recent financial year (1)	X	$26.67	
Market Value of Class		$160,020,000	$160,020,000 (B)

Series X

Total number of securities outstanding at the end of the most recent financial year:		6,000,000	
Simple average of the closing price as of the last trading day of each of the months of the most recent financial year (1)	X	$26.97	
Market Value of Class		$161,820,000	$161,820,000 (B)

Total Capitalization (A+B)	$5,090,284,000
Total Fee payable pursuant to Appendix A of the Rule	$65,000

(1) See Schedule A

Schedule A

Simple Average of Closing Price On Last Trading Day of Each Month of 2005

	Canadian Utilities Limited						
	Class A Non-Voting Shares	Class B Common Shares	Preferred Shares				
			Series Q	Series R	Series S	Series W	Series X
January	29.91	30.02	26.00	25.50	27.00	27.06	27.61
February	30.50	30.54	25.70	25.50		27.10	27.12
March	30.68	30.76	25.69	24.65		26.05	26.40
April	30.85	30.38	25.70	25.06	27.10	26.39	26.67
May	32.08	32.32	25.69	25.05	27.50	26.65	26.85
June	34.99	34.50	25.31	25.00	27.10	26.92	26.90
July	35.50	35.03	25.55	25.34	27.10	26.35	26.98
August	38.06	38.13	25.25	25.20		26.68	26.96
September	39.51	40.01	25.70	25.25	27.10	26.45	26.90
October	39.68	39.56	25.59	25.10	27.50	26.68	27.00
November	42.60	43.24	25.11	25.05	27.50	26.67	27.01
December	43.98	43.85	25.99	25.06	27.50	27.00	27.25
Average	$35.69	$35.69	$25.61	$25.15	$27.27	$26.67	$26.97

Note:
(1) Prices of Class A non-voting and Class B common shares adjusted to reflect two for one share split.

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED
An ATCO Company

Release

CORPORATE OFFICE
1500, 909 - 11 AVENUE SW, CALGARY, ALBERTA T2R 1N6
TELEPHONE (403) 292-7500

February 3, 2006

ATCO Gas Receives Decision on General Rate Application

CALGARY, Alberta – On January 27, 2006, ATCO Gas received a decision on its phase one General Rate Application (GRA) which was filed with the Alberta Energy and Utilities Board (AEUB) in May 2005 for 2005, 2006 and 2007. 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.

As part of this GRA, on August 28, 2005, ATCO Gas received a decision from the AEUB approving an interim refundable rate increase. The GRA decision has confirmed the revenues from these interim rates for 2005 and, therefore, will not have a material impact on the 2005 earnings of the company.

There will be no immediate impact on ATCO Gas distribution rates as interim rates will continue until final rates are decided by the AEUB in late 2006 or early 2007.

The GRA decision approved a return on common equity as determined by the AEUB's standardized rate of return methodology. The return on common equity is 9.5% in 2005, 8.93% in 2006, and is yet to be determined for 2007. The impact of the GRA decision for 2006 and 2007 cannot be determined until final rates are decided by the AEUB.

ATCO Gas is a wholly owned subsidiary of Canadian Utilities Limited which is part of the ATCO Group of Companies. ATCO Group is an Alberta based, worldwide organization of companies with more than 7,000 employees actively engaged in Power Generation, Utilities and Global Enterprises. More information about Canadian Utilities Limited can be found on its website, www.canadian-utilities.com.

For more information contact:

K.M. (Karen) Watson
Senior Vice President
& Chief Financial Officer
Canadian Utilities Limited
(403) 292-7502

S.W. (Siegfried) Kiefer
Managing Director, Utilities
Canadian Utilities Limited
(403) 292-7652

ATCO GROUP

NewsRelease

ATCO LTD. & CANADIAN UTILITIES LIMITED
Corporate Head Office: 1400, 909 -11 Avenue S.W. Calgary, Alberta T2R 1N6 Telephone: (403) 292-7500 Fax: (403) 292-7623

February 9, 2006

ATCO Gas Receives Decision on Supreme Court of Canada Appeal

CALGARY, Alberta – The Supreme Court of Canada today confirmed an earlier Alberta Court of Appeal ruling that ATCO Gas and Pipelines Ltd. is the sole owner of its assets.

"We are pleased to resolve this important point of principle which confirms the utility company's right to the benefits of owning its property," said Nancy Southern, President & Chief Executive Officer, ATCO Ltd. and Canadian Utilities Limited.

In its decision regarding the sale of property owned by the utility, the Supreme Court reiterated the important role of the Alberta Energy & Utilities Board (EUB) to determine fair, equitable and reasonable rates for consumers while balancing the property rights retained by owners, as recognized in a free market economy.

This decision will not impact the 2005 earnings of the company, as the Supreme Court has directed the EUB to issue a new decision in accordance with the Supreme Court's ruling. Net proceeds totaling $4.1 million from the sale of the downtown property owned by ATCO Gas are being held pending EUB approval.

ATCO Gas & Pipelines Ltd. is a wholly owned subsidiary of Canadian Utilities Limited, part of the ATCO Group of Companies. ATCO Group is an Alberta based, worldwide organization of companies with more than 7,000 employees actively engaged in Power Generation, Utilities and Global Enterprises. More information about ATCO can be found on its website, www.atco.com.

For more information contact:

N.C. (Nancy) Southern
President & Chief
Executive Officer
ATCO Ltd. and Canadian
Utilities Limited
(403) 292-7561

K.M. (Karen) Watson
Senior Vice President
& Chief Financial Officer
ATCO Ltd. and Canadian
Utilities Limited
(403) 292-7503

CIBC Mellon Global Securities Services Company
CIBC Mellon Trust Company

February 17, 2006

BC Securities Commission
Saskatchewan Securities Commission
Ontario Securities Commission
The Office of the Administrator of Securities
- New Brunswick
Registrar of Securities – Prince Edward Island

Alberta Securities Commission
Manitoba Securities Commission
Quebec Securities Commission
Nova Scotia Securities Commission
Securities Division - Newfoundland

Dear Sirs:

RE: Canadian Utilities Limited
Annual Meeting of Shareholders

Pursuant to a request from our Principal, we wish to advise you of the following dates in connection with their Annual Meeting of Shareholders:

DATE OF MEETING	May 4, 2006
RECORD DATE FOR NOTICE:	March 15, 2006
RECORD DATE FOR VOTING:	March 15, 2006
BENEFICIAL OWNERSHIP DETERMINATION DATE:	March 15, 2006
SECURITIES ENTITLED TO NOTICE:	Class A Non-voting Class B Common
SECURITIES ENTITLED TO VOTE:	Class B Common

Yours truly,

CIBC MELLON TRUST COMPANY

"Signed"

Sandra Evans
Associate Relationship Manager
(403) 232-2416
sandra_evans@cibcmellon.com

cc: Pat Spruin, Canadian Utilities Limited
CDS & Co.
Judy Power, CIBC Mellon Trust Company

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED

An ATCO Company

2005 ANNUAL INFORMATION FORM

February 22, 2006

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FORWARD-LOOKING INFORMATION

This Annual Information Form ("AIF") contains forward-looking statements pertaining to purchase obligations, planned capital expenditures, anticipated completion dates of projects, the impact of changes in government regulation and non-regulated generating capacity subject to long term contracts. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

DEFINITIONS OF CERTAIN TERMS

Certain terms used in this Annual Information Form are defined below:

"AEUB" means the Alberta Energy and Utilities Board;

"AGP" means ATCO Gas and Pipelines Ltd.;

"Alberta Power (2000)" means Alberta Power (2000) Ltd.;

"Alberta Power Pool" means the market for electricity in Alberta operated by the Alberta Electric System Operator;

"ASHCOR Technologies" means ASHCOR Technologies Ltd.;

"ATCO Electric" means ATCO Electric Ltd.;

"ATCO Frontec" means ATCO Frontec Corp. together with its subsidiaries;

"ATCO Gas" means the natural gas distribution division of AGP;

"ATCO I-Tek" means ATCO I-Tek Inc.

"ATCO I-Tek Business Services" means ATCO I-Tek Business Services Ltd.;

"ATCO Midstream" means ATCO Midstream Ltd.;

"ATCO Pipelines" means the natural gas transportation division of AGP;

"ATCO Power" means ATCO Power Ltd. together with its subsidiaries;

"ATCO Resources" means ATCO Resources Ltd., a wholly owned subsidiary of ATCO Ltd.;

"ATCO Travel" means ATCO Travel Ltd.;

"ATCO Utility Services" means ATCO Utility Services Ltd.;

"BPL" means Barking Power Limited;

"Class A shares" means the Class A non-voting shares of the Corporation;

"Class B shares" means the Class B common shares of the Corporation;

"Corporation" means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries;

"CU" means Canadian Utilities Limited;

"CU Water" means CU Water Limited;

"EEEP" means the Edmonton Ethane Extraction Plant;

"EUA" means the Electric Utilities Act (Alberta);

"Genics" means Genics Inc.;

"GUA" means the Gas Utilities Act (Alberta);

"km" means kilometre;

"Mmcf" means one million cubic feet and "Bcf" means one billion cubic feet;

"negotiated settlement" means an agreement related to a revenue requirement and/or customer rates for a specific period of time resulting from direct negotiations between a utility and its customers. A negotiated settlement avoids the need for a general rate application for the duration of the agreement. All negotiated settlements must be approved by the AEUB;

"NLD" means Northland Utilities (NWT) Limited;

"NUY" means Northland Utilities (Yellowknife) Limited;

"petajoule" means a unit of energy equal to approximately 948.2 billion British thermal units, "terajoule" means a unit of energy equal to approximately 948.2 million British thermal units and "gigajoule" means a unit of energy equal to approximately 948.2 thousand British thermal units;

"PPA" means power purchase arrangements that became effective on January 1, 2001, as part of the process of restructuring the electric utility business in Alberta. The PPA's are legislatively mandated and approved by the AEUB;

"REA" means Rural Electrification Association. REA's are constituted under the Rural Utilities Act (Alberta) by groups of persons carrying on farming operations. Each REA purchases electric power for distribution to its members through a distribution system owned by that REA;

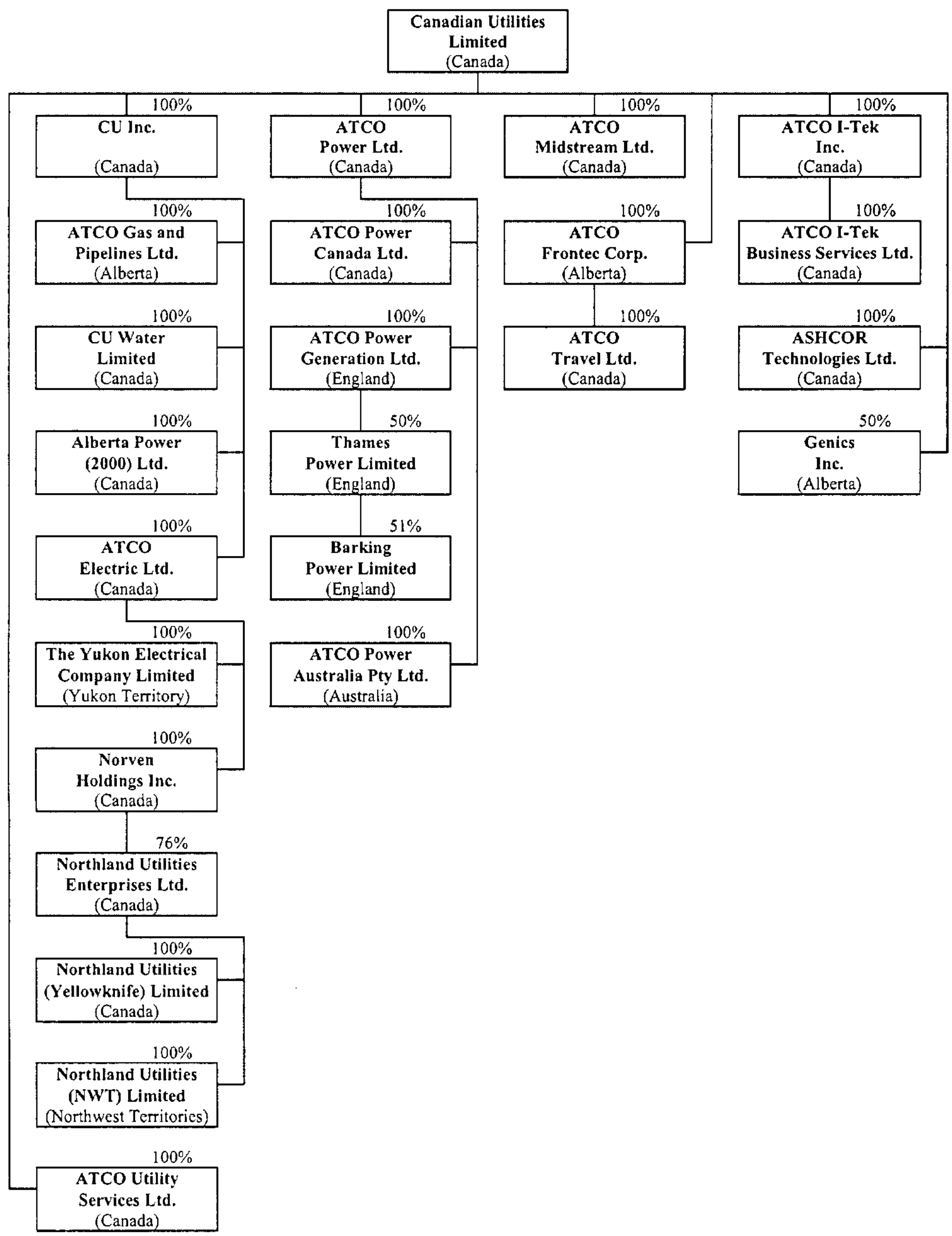
"Thames Power" means Thames Power Limited;

"YECL" means The Yukon Electrical Company Limited.

CANADIAN UTILITIES LIMITED

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927, and was continued under the Canada Business Corporations Act on August 15, 1979. The common share capital of the Corporation was reorganized on September 10, 1982. The address of the principal office of the Corporation is 1600, 909 – 11th Avenue S.W., Calgary, Alberta T2R 1N6 and the registered office of the Corporation is 20th Floor, 10035 – 105 Street, Edmonton, Alberta, T5J 2V6.

The following chart includes the names of the principal operating subsidiaries of the Corporation, the jurisdictions under the laws of which they are organized and the percentages of their shares beneficially owned or over which control or direction is exercised by the Corporation.



BUSINESS OF THE CORPORATION

The Corporation is a holding company. Its principal operating subsidiaries are engaged in regulated natural gas and electric energy operations, primarily in Alberta, and in related non-regulated operations. Regulated operations are conducted by ATCO Electric and its subsidiaries, NLD, NUY and YECL, ATCO Gas and ATCO Pipelines. Included in regulated operations are the generating plants of Alberta Power (2000), which 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 expiry of the PPA's. 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 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, NLD, NUY and YECL, 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 and the regulated supply of electricity by Alberta Power (2000).

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, the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel.

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

Three Year History

The significant events and conditions that have influenced the general development of the Corporation's business over the past three years are summarized below. A number of these events and conditions are discussed in greater detail elsewhere in this Annual Information Form.

2005:

- Volatility in prices received for electricity sold to the Alberta Power Pool and for electricity sold into the United Kingdom Power Exchange Market by ATCO Power.
- Fluctuations in temperatures affecting ATCO Gas' operations.
- In 2005, the Corporation received $83.1 million as its share of the partial settlement of the claim for damages related to TXU Europe's breach of its contract with BPL. An additional payment of $16.6 million was received on January 19, 2006 and a final installment of approximately $1.6 million is expected in the second quarter of 2006. The settlement is expected to generate earnings after income taxes and non-controlling interests of approximately $69 million, based on foreign currency exchange rates in effect on March 30, 2005, 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 the foreign currency exchange rates in effect at the time the earnings are recognized.

- In November 2005, the AEUB announced a generic return on common equity of 8.93% for 2006. In January 2006, the AEUB clarified that the generic return on equity determined in accordance with the generic cost of capital decision should apply to each year of the test period in the companies 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.

- In November 2005, the AEUB approved ATCO Pipelines as the party to manage the acquisition and sale of working gas at its salt cavern storage. Salt cavern working gas had historically been acquired by ATCO Gas and its predecessors.

- In May 2005, ATCO Gas filed a general rate application with the AEUB for the 2005, 2006 and 2007 test years requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. In June 2005, ATCO Gas filed an application requesting interim refundable rates pending the AEUB's decision on the general rate application. On August 28, 2005, ATCO Gas received a decision from the AEUB approving an interim refundable rate increase, to be collected from northern customers, of $7.0 million. A decision from the AEUB was received on January 27, 2006, which resulted in an earnings impact that is not materially different from the earnings based on the interim rates approved by the AEUB in August 2005.

- In April 2005, ATCO Midstream leased the full storage capacity at ATCO Gas' Carbon natural gas storage facility for the 2005/2006 year resulting in higher storage revenues due to higher capacity leased and the timing and demand of storage capacity sold.

2004:

- Volatility in prices received for electricity sold to the Alberta Power Pool by ATCO Power.

- In August 2004, the Corporation reorganized its structure into three business groups: **Utilities** (ATCO Gas, ATCO Electric and its subsidiaries, NLD, NUY and YECL, ATCO Pipelines, CU Water, ATCO Utility Services); **Power Generation** (ATCO Power, Alberta Power (2000)); and **Global Enterprises** (ATCO Midstream, ATCO Frontec, ATCO I-Tek and its subsidiary ATCO I-Tek Business Services, ASHCOR Technologies, Genics, ATCO Travel).

- In August 2004, ATCO Electric completed construction of a $99.0 million, 350 kilometre 240 kilovolt transmission line between Fort McMurray and Whitefish Lake.

- In a decision dated July 13, 2004, the AEUB awarded ATCO Pipelines additional revenue with respect to the revenue forecasts of certain industrial customers.

- In July 2004, ATCO Power's Brighton Beach generating plant in Windsor, Ontario was completed and commenced commercial operations. All of ATCO Power's generating plants are now operational.

- In July 2004, the AEUB issued its generic cost of capital decision, establishing a standardized approach for determining the rate of return on common equity for each utility company (ATCO Electric, ATCO Gas and ATCO Pipelines) regulated by the AEUB. The decision also established capital structures for each utility company regulated by the AEUB. This resulted in:
  - ATCO Electric obtaining an approved 2004 return on common equity of 9.60% and a common equity ratio of 33% for its transmission operations and 37% for its distribution operations. The impact of this decision was an increase in the common equity that ATCO Electric was allowed to earn a return on by $22.3 million in 2004.
  - ATCO Pipelines obtaining an approved 2004 rate of return on common equity of 9.60% and a common equity ratio of 43%.
  - ATCO Gas was not impacted by this decision for 2004 as its return on common equity of 9.50% and its common equity ratio of 37% had already been approved by the AEUB in a decision dated October

1, 2003. The Generic Cost of Capital decision approved, among other things, ATCO Gas' common equity ratio of 38% beginning in 2005.

- In 2001, the Corporation received and paid income tax reassessments of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. The Corporation did not agree with this reassessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities.

  During 2003, the Corporation was successful in appealing the reassessments to the Tax Court of Canada. The Federal Government appealed the Tax Court's decision to the Federal Court of Appeal, which issued a decision on June 18, 2004 in favor of the Corporation. The Federal Government did not appeal the Federal Court of Appeal's decision to the Supreme Court of Canada. The Corporation received a refund of $15.1 million, including interest, and reversed the future income tax reduction of $12.9 million.

- On May 4, 2004, ATCO Gas and ATCO Electric closed the transfer of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc ("Transfer of the Retail Energy Supply Businesses") for $90 million. The transfer increased 2004 earnings by $55.1 million. As a result of the transfer, ATCO Gas and ATCO Electric are no longer involved in arranging for the supply and sale of natural gas and electricity to customers, but continue to own the assets and provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return. ATCO I-Tek Business Services entered into a 10 year contract to provide billing and call centre services to DEML.

2003:

- Volatility in prices received for electricity sold to the Alberta Power Pool by ATCO Power.

- In a decision dated December 2, 2003, the AEUB approved for ATCO Pipelines, among other things, a rate of return on common equity of 9.50% and a common equity ratio of 43.5% for 2003. The decision also set aside certain transactions with affiliates that are to be finalized through a collaborative benchmarking process with customers and the AEUB. This process is still ongoing.

- In December 2003, ATCO Power's Scotford generating plant at Scotford, Alberta was completed and commenced commercial operations.

- In a decision dated October 2, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.40% and a common equity ratio of 32% for ATCO Electric's transmission operations and 35% for its distribution operations for 2003. These reductions in the common equity ratios reduced the common equity that ATCO Electric was allowed to earn a return on by $83.0 million for 2003. The decision also set aside certain transactions with affiliates that are to be finalized through a collaborative benchmarking process with customers and the AEUB. This process is still ongoing.

- In a decision dated October 1, 2003, the AEUB approved for ATCO Gas, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37% for 2003 and 2004. The decision also set aside certain transactions with affiliates that are to be finalized through a collaborative benchmarking process with customers and the AEUB. This process is still ongoing.

- In September 2003, ATCO Frontec's contract with the Department of National Defense to provide support services for six peace-keeping installations in Bosnia-Herzagovina expired.

- In April 2003, the AEUB determined that it would proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to determine the rate of return on equity and capital structure for all utilities under the jurisdiction of the AEUB.

- In the first quarter of 2003, ATCO Gas commenced the first phase of a $278 million project to relocate natural gas meters currently inside homes to the outside. The project will make the distribution system safer by relocating and replacing aging infrastructure, improve metering accuracy and accessibility, and facilitate more efficient meter reading. The AEUB approved a program which will result in meters with underground entries being relocated over 10 years and all other inside meters moved as part of the existing meter recall program The decision also allows ATCO Gas to move meters at any time if they are deemed unsafe.

- In January 2003, ATCO Power's Cory generating plant near Saskatoon, Saskatchewan was completed and commenced commercial operations.

- In January 2003, ATCO Power's Muskeg River generating plant near Fort McMurray, Alberta was completed and commenced commercial operations.

Utilities

Natural Gas Distribution

ATCO Gas is primarily engaged in the business of distributing natural gas throughout Alberta and in the Lloydminster area of Saskatchewan. Although ATCO Gas is the major natural gas distributor in Alberta, certain areas are served by other natural gas utilities.

ATCO Gas' principal markets for the distribution of natural gas are in the communities of Edmonton, Calgary, Airdrie, Camrose, Fort McMurray, Grande Prairie, Lethbridge, Lloydminster, Red Deer, St. Albert and Sherwood Park, which have a combined population of approximately 2,108,000. Also served are 279 smaller communities as well as rural areas having a combined population of approximately 558,000, located on or in the vicinity of ATCO Pipelines' transportation systems or the natural gas transportation pipelines of other companies. ATCO Gas provides approximately 940,000 customers with natural gas service, of whom approximately 75% are located in the 11 communities named above.

The number of customers served by ATCO Gas as at the end of each of the last two years was as follows:

	2005	2004
Residential	858,618	834,883
Commercial	80,630	79,084
Industrial	350	359
Other	-	21
Total	939,598	914,347

ATCO Gas owns and operates approximately 35,400 km of distribution mains. In addition, ATCO Gas owns modern service and maintenance facilities in major centres.

Revenues and earnings of ATCO Gas are affected by temperature and consequently winter weather can have a significant impact. During a typical year, more than 90% of the earnings of ATCO Gas are generated during the months of January, February, November and December.

The amounts of natural gas distributed by ATCO Gas for each of the last two years were as follows:

	2005	2004
	(petajoules)	
Residential	103.8	107.3
Commercial	96.9	98.1
Industrial	14.4	14.5
Other	0.4	2.8
Total	215.5	222.7

Natural Gas Supply

As a result of the Transfer of the Retail Energy Supply Businesses to DEML in May 2004, ATCO Gas is no longer involved in arranging for the supply and sale of natural gas to customers, but will continue to own the assets and provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return.

Prior to April 1, 2005, as directed by the AEUB, ATCO Gas purchased fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. Effective April 1, 2005, as directed by the AEUB, ATCO Gas no longer purchases fixed quantities of natural gas related to storage purchases and operational contracts pertaining to its natural gas field storage facility at Carbon, Alberta. ATCO Gas has leased the entire storage capacity of the Carbon facility to ATCO Midstream for the period April 1, 2005 to March 31, 2006. For additional information related to the leasing of the Carbon natural gas storage facility to ATCO Midstream, refer to the Regulatory Matters, ATCO Gas section of the Corporation's Management's Discussion and Analysis ("MD&A"), page 16, which is available at www.sedar.com.

In 2003, ATCO Gas commenced the first phase of a $278 million project to relocate natural gas meters currently inside homes to the outside. The project will make the distribution system safer by relocating and replacing aging infrastructure, improve metering accuracy and accessibility, and facilitate more efficient meter reading. The AEUB approved a program which will result in meters with underground entries being relocated over 10 years and all other inside meters moved as part of the existing meter recall program. The decision also allows ATCO Gas to move meters at any time if they are deemed unsafe.

CU Water

CU Water is engaged in the transmission and distribution of water. CU Water owns and operates a distribution system to supply water to rural customers and small towns east of Edmonton. At the end of 2005, 976 customers were being served directly by CU Water and, in addition, bulk water sales were being made to the towns of Tofield and Viking and to 13 commercial water haulers. The operations of CU Water are subject to regulation by the AEUB.

Natural Gas Transportation

ATCO Pipelines is engaged in the business of transporting natural gas throughout Alberta and the operation of a salt cavern storage peaking facility.

ATCO Pipelines owns and operates extensive natural gas transportation systems. The systems consist of approximately 8,343 km of pipelines, 23 compressor sites and a salt cavern storage peaking facility. The systems have 217 producer receipt points, 78 interconnections with TransCanada Pipelines Limited, five interconnections with Alliance Pipeline and one interconnection with Many Islands Pipelines.

ATCO Pipelines' revenues are based primarily on contractual arrangements for access to its transportation systems. Contract demand for access, and interruptible (IT), overrun (OR) and variable volumes for each of the last two years was as follows:

	2005	2004
	(terajoules/day)	
Contract Demand:		
Producer	1,291	1,253
Industrial	1,015	1,054
Distribution	93	89
Affiliates	2,431	2,210
Total	4,830	4,606
IT/OR/Variable Volumes:		
Producer	243	257
Industrial	241	258
Distribution	2	7
Total	486	522
Total Contract Demand and IT/OR/Variable Volumes	5,316	5,128

The AEUB approved the conversion of sales service to transportation service for certain customers of ATCO Pipelines. This conversion was completed during 2005.

Electric Distribution and Transmission

ATCO Electric is engaged in the business of transmitting and distributing electric energy to 238 communities as well as rural areas in east-central and northern Alberta. Included are the communities of Drumheller, Lloydminster, Grande Prairie and Fort McMurray as well as the oil sands areas near Fort McMurray and the heavy oil areas near Cold Lake and Peace River. Electric utility service is also provided to one community in British Columbia and to two communities in Saskatchewan. YECL serves 19 communities in the Yukon Territory, including the capital city of Whitehorse, and NUY and NLD serve 9 communities in the Northwest Territories, including the capital city of Yellowknife.

Electricity distributed to the various classes of customers for each of the last two years was as follows:

	2005		2004	
	Millions of Kilowatt Hours	**%**	**Millions of Kilowatt Hours**	**%**
Industrial	6,583	66	6,597	67
Commercial	1,826	19	1,796	18
Residential	1,023	10	1,032	10
Rural, REAs and other	494	5	485	5
Total	9,926	100	9,910	100

The aggregate population of the areas provided with electric utility service by ATCO Electric, NUY, NLD and YECL is approximately 456,000 and service is provided to approximately 211,000 customers. ATCO Electric has been assigned approximately 65% of the designated service area within Alberta which contains approximately 15% of the existing provincial electrical load and 13% of the existing population.

The number of customers served by ATCO Electric, NUY, NLD and YECL as at the end of each of the last two years was as follows:

	2005		2004	
	Number	%	Number	%
Industrial	10,847	5	10,691	5
Commercial	28,673	14	28,068	14
Residential	141,806	67	138,066	67
Rural, REAs and other	29,536	14	29,421	14
Total	210,862	100	206,246	100

ATCO Electric, NUY, NLD and YECL own and operate extensive electric transmission and distribution systems. The systems consist of approximately 9,400 km of main transmission lines and 59,800 km of distribution lines. In addition, ATCO Electric delivers power to and operates approximately 12,100 km of REA-owned distribution lines.

ATCO Electric, NUY, NLD and YECL own and operate 33 diesel, natural gas turbine and hydro generating plants having an aggregate nameplate capacity of 62 megawatts in Alberta and in the Yukon and Northwest Territories. The maximum peak load demand for these plants during the year ended December 31, 2005, was 32 megawatts.

Franchises

AGP, ATCO Electric, YECL, NUY and NLD distribute natural gas and electricity in incorporated communities under the authority of franchises or by-laws and in rural areas under approvals, permits or orders issued pursuant to applicable statutes.

In Edmonton, distribution of natural gas is carried on under the authority of an exclusive franchise. In 2004, AGP entered into an agreement with the City of Edmonton for a 10 year renewal of the franchise to November 15, 2015. The franchise renewal is subject to the right of the City of Edmonton, at the end of the renewal period, to purchase all of AGP's assets within the city and its assets outside the city used in supplying natural gas to the city. The purchase price would be the amount of the actual value thereof as a going concern plus 10% of such value. Although the franchise agreement gives the City certain rights of purchase, since 1935 the City has granted renewals for 10 year periods.

In Calgary, distribution of natural gas is carried on under the authority of a municipal by-law. The rights of AGP under this by-law, while not exclusive, are unrestricted as to time. The by-law does not confer any right on the City of Calgary to acquire the facilities used in providing the service.

The franchises under which service is provided in other incorporated communities in Alberta and in the Northwest Territories have been granted for periods of up to 20 years. These franchises are exclusive to AGP, ATCO Electric, NUY or NLD and are renewable by agreement for further periods not exceeding 20 years each in the case of AGP and 10 years in the case of ATCO Electric, NUY and NLD. If any franchise is not renewed, it remains in effect until such time as either party, with the approval of the prevailing regulatory authority, terminates it on six months written notice. Upon termination of a franchise the municipality may purchase the facilities used in connection with that franchise at a price to be agreed upon or, failing agreement, to be fixed by the prevailing regulatory authority. The franchise under which service is provided in the Yukon Territory was granted under the Public Utilities Act (Yukon Territory) and has no set expiry date.

Power Generation

Power generation operations are conducted by Alberta Power (2000) and ATCO Power.

Regulated (Alberta Power (2000))

Alberta Power (2000) is engaged in the regulated supply of electricity in Alberta. Alberta Power (2000)'s assets are operated by ATCO Power pursuant to management agreements. 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 expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the life of the related generating plant and December 31, 2020.

Substantially all of the electricity generated by Alberta Power (2000) is sold pursuant to PPA's with EPCOR Utilities Inc. (Battle River generating plant) and TransCanada Energy Ltd. (Sheerness generating plant). The Sheerness PPA was sold to TransCanada Energy Ltd. by the Alberta Balancing Pool effective January 1, 2006 and the Rainbow PPA expired on December 31, 2005. Under the PPA's, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPA's are based.

Alberta Power (2000) continues to operate the Rainbow and Sturgeon generating plants and the electricity generated is sold to the Alberta Power Pool. Alberta Power (2000) has one year from the expiry of the PPA's to determine whether to decommission the plants or continue operating them. To date, no decision has been made with respect to the ongoing status of these plants.

The name plate capacity ratings of Alberta Power (2000)'s generating plants as at December 31, 2005 are listed below.

Plant	Commissioning Date	Type of Generating Plant	Name Plate Capacity Rating (megawatts)	PPA Purchaser	PPA Expiry Date
Battle River					
Unit 3	1969	coal-fired steam turbine	150	EPCOR Utilities Inc.	2013
Unit 4	1973	coal-fired steam turbine	150	EPCOR Utilities Inc.	2013
Unit 5	1981	coal-fired steam turbine	370	EPCOR Utilities Inc.	2020
			670		
Sheerness (1)(2)					
Unit 1	1986	coal-fired steam turbine	190	TransCanada Energy Ltd.	2020
Unit 2	1991	coal-fired steam turbine	190	TransCanada Energy Ltd.	2020
			380		
Rainbow (3)....	1968	natural gas turbine	88		2005
Sturgeon..........	1957	natural gas turbine	18	Merchant	
Total			1,156		

Note:

(1) Alberta Power (2000)'s ownership of the 760 megawatt name plate capacity.

(2) TransCanada Energy Ltd. became the PPA purchaser on January 1, 2006; previously the PPA purchaser was the Alberta Balancing Pool.

(3) PPA expired December 31, 2005.

Alberta Power (2000) manages the Sheerness generating plant under long term agreements with TransAlta Cogeneration L.P. for the equal sharing of ownership and cost of electric capacity.

Alberta Power (2000) owns or has committed under long term contracts sufficient coal supplies for the anticipated lives of its Battle River and Sheerness generating plants.

Non-Regulated (ATCO Power)

ATCO Power is engaged in the non-regulated supply of electricity and cogeneration steam in Canada, the United Kingdom and Australia. ATCO Power also manages Alberta Power (2000)'s assets. ATCO Power continues to focus its development efforts on independent power production projects in Canada, Australia and the United Kingdom.

ATCO Power's non-regulated independent cogeneration plants and generating plants, with their respective commissioning dates and name plate capacity ratings, are shown below.

Location	Commissioning Date	Name Plate Capacity Rating (megawatts)	Ownership	Net Ownership (megawatts)
Canada:				
McMahon, B.C.	1993	120	50.0%	60
Primrose, Alberta	1998	85	40.0%	34
Poplar Hill, Alberta	1998	45	80.0%	36
Rainbow Lake, Alberta	1999	90	40.0%	36
Joffre, Alberta	2000	480	32.0%	154
Valleyview, Alberta	2001	45	80.0%	36
Muskeg River, Alberta	2003	170	56.0%	95
Cory, Saskatchewan	2003	260	40.0%	104
Oldman River, Alberta	2003	32	80.0%	26
Scotford, Alberta	2003	170	80.0%	136
Brighton Beach, Ontario	2004	580	40.0%	232
United Kingdom:				
Barking, London	1995	1,000	25.5%	255
Heathrow Airport	1990	14	50.0%	7
Australia:				
Osborne, South Australia	1998	180	50.0%	90
Bulwer Island, Queensland	2001	33	50.0%	17
Total		3,304		1,318

Canada

ATCO Power has a 50% interest in a joint venture with McMahon Power Holdings L.P. The joint venture owns and operates the 120 megawatt McMahon cogeneration plant at Taylor, British Columbia. All of the electricity generated is sold to British Columbia Hydro and Power Authority pursuant to an electricity purchase agreement expiring in 2014. In addition to generating electricity, the plant sells steam to Westcoast Energy Inc.'s adjacent natural gas processing plant.

A joint venture, owned by ATCO Power, Canadian Natural Resources Limited ("CNRL") and ATCO Resources, operates an 85 megawatt cogeneration power plant (the "Primrose Steam Enhancement Plant") near Bonnyville, Alberta. The joint venture sells electricity and steam to CNRL for use in its heavy oil recovery process. Any excess electricity generated is sold to the Alberta Power Pool or to specific customers. ATCO Power owns a 40% interest in the project, ATCO Resources owns 10% and CNRL owns 50%.

ATCO Power operates a 45 megawatt natural gas-fired generating plant at Poplar Hill near Grande Prairie, Alberta. Revenues are derived from power sold to the Alberta Power Pool and from transmission deferral credits contracted with the Alberta Power Pool. ATCO Power owns an 80% interest in the project and ATCO Resources owns 20%.

ATCO Power operates a 90 megawatt natural gas-fired generating plant at Rainbow Lake, Alberta which sells steam and electricity to Husky Energy Inc. ("Husky"). Surplus electricity is sold to the Alberta Power Pool. ATCO Power owns a 40% interest in the project, ATCO Resources owns 10% and Husky owns 50%.

ATCO Power, EPCOR Power Development Corporation and NOVA Chemicals Corporation ("NOVA") are participants in a joint venture which operates a 480 megawatt natural gas-fired cogeneration plant near Joffre, Alberta. ATCO Power is the operator of the facility. NOVA purchases all of the steam and approximately 25% of the electricity produced for use in NOVA's Joffre petrochemical site under an energy purchase agreement expiring in 2020. The balance of the output is sold to the Alberta Power Pool or to specific customers. ATCO Power owns a 32% interest in the project, ATCO Resources owns 8%, EPCOR Power Development Corporation owns 40% and NOVA owns 20%.

ATCO Power operates a 45 megawatt natural gas-fired generating plant near Valleyview, Alberta. All of the electricity produced by the plant is sold to the Alberta Power Pool. ATCO Power owns an 80% interest in the project and ATCO Resources owns 20%.

ATCO Power and SaskPower International Inc. ("SPI") are participants in a joint venture which operates a 170 megawatt natural gas-fired cogeneration plant and related facilities at the Athabasca Oil Sands Project ("AOSP") Muskeg River mine near Fort McMurray, Alberta. Approximately one-half of the electricity and all of the steam produced by the plant are supplied to AOSP for use in its Muskeg River mine. The balance of the electricity generated is sold to the Alberta Power Pool. ATCO Power owns a 56% interest in the project, ATCO Resources owns 14% and SPI owns 30%.

ATCO Power and SPI are participants in a joint venture which operates a 260 megawatt natural gas-fired cogeneration plant at Potash Corporation of Saskatchewan Inc.'s Cory Mine, located near Saskatoon, Saskatchewan. ATCO Power is the operator of the facility. Saskatchewan Power Corporation has agreed to purchase all of the electricity generated by the plant for 25 years. ATCO Power owns a 40% interest in the project, ATCO Resources owns 10% and SPI owns 50%.

ATCO Power operates a 32 megawatt hydroelectric generating plant at the Oldman River dam near Pincher Creek, Alberta. All of the electricity produced by the plant is sold to the Alberta Power Pool. ATCO Power owns an 80% interest in the project and ATCO Resources owns 20%. The Piikani Nation of Brockett, Alberta has an option which expires March 31, 2006, to purchase a 25% interest in the project.

ATCO Power operates a 170 megawatt natural gas-fired cogeneration plant at the AOSP upgrader at Scotford, Alberta. Approximately 80% of the electricity and all the thermal energy produced by the plant is supplied to AOSP for use in the upgrader and the balance of the electricity is sold to the Alberta Power Pool. ATCO Power owns an 80% interest in the project and ATCO Resources owns 20%.

A partnership formed by ATCO Power and Ontario Power Generation ("OPG") owns and operates the Brighton Beach power plant, a 580 megawatt natural gas-fired combined cycle generating plant in Windsor, Ontario. Coral Energy Canada Inc. supplies and pays for the natural gas used at the plant and owns, markets and trades all the electricity produced under contracts expiring in 2024. ATCO Power owns a 40% interest in the project, ATCO Resources owns 10% and OPG owns 50%.

At December 31, 2005, all of ATCO Power's non-regulated independent generating plants were in service.

United Kingdom

ATCO Power and Balfour Beatty plc, a United Kingdom construction group, each own a 50% equity interest in Thames Power, a London, England based company. Thames Power has a 51% interest in BPL which owns a 1,000 megawatt natural gas-fired combined cycle generating plant at Dagenham in London, England (the "Barking power plant"). EDF Energy plc ("EDF") and SSE Energy Supply Limited ("SSE") own the remaining 49% interest in BPL. EDF and SSE have entered into long term agreements expiring in 2010 to purchase 72.5% of the electricity produced at the plant. The remaining 275 megawatts of power is being sold into the United Kingdom electricity market on a merchant basis under a one year marketing agreement expiring September 30, 2006. The majority of the 275 megawatts has been sold forward under this agreement through the end of March 2006 with smaller volumes sold forward through September 2006. The Barking power plant is operated by ATCO Power.

ATCO Power has a 50% interest in a joint venture with a subsidiary of EDF. The joint venture owns and operates a facility consisting of a 14 megawatt natural gas turbine, 40 megawatts of boiler capacity and an associated heat distribution system at London's Heathrow Airport. The joint venture has a 15 year energy services contract, expiring in 2010, with BAA plc, owner of the Heathrow Airport, for all of the electric energy and hot water produced by the facility.

Australia

ATCO Power has a 50% interest in a joint venture with Origin Energy Limited ("Origin"). The joint venture owns and operates a 180 megawatt cogeneration plant in Osborne, South Australia. This joint venture supplies electricity to Flinders Osborne Trading Pty Ltd ("FOT") under a 20 year electricity purchase agreement expiring in 2018. In addition to generating electricity, the plant provides steam under a 20 year agreement, expiring in 2018, to Penrice Soda Products Pty Ltd. The Government of South Australia has guaranteed the obligations of FOT under these agreements.

ATCO Power has a 50% interest in a consortium with Origin. The consortium owns and operates a 33 megawatt natural gas-fired cogeneration plant and other utility infrastructure at BP Amoco plc's ("BP") Bulwer Island refinery, near Brisbane, Queensland. All of the power and steam produced by the plant is sold to BP under a 20 year agreement expiring in 2021.

Global Enterprises

Non-Regulated Natural Gas Gathering, Processing and Storage

ATCO Midstream owns and operates non-regulated gathering and processing facilities in Alberta. ATCO Midstream provides natural gas procurement/load balancing services for other ATCO subsidiaries, management services for ATCO Gas' storage field at Carbon and markets non-regulated storage products. Effective April 1, 2005, ATCO Midstream leased the full storage capacity at ATCO Gas' Carbon storage facility for the period April 1, 2005 to March 31, 2006. Upon the Transfer of the Retail Energy Supply Businesses in 2004, ATCO Midstream ceased providing natural gas procurement services to ATCO Gas.

ATCO Midstream owns a 51.3% interest in EEEP. Located in south Edmonton, EEEP is a natural gas processing plant which extracts ethane and other natural gas liquids from natural gas flowing into the Edmonton market area. Ethane is sold to an Alberta ethylene producer under a long term contract that expires in December 2012 and other natural gas liquids are sold under another long term contract that expires in May 2014.

ATCO Midstream's natural gas liquids extraction plants with plant capacity ratings are shown below:

Facility	Extraction	Plant Capacity (Mmcf/day)	Ownership	Net Ownership (Mmcf/day)
Edmonton Ethane Extraction Plant	C2 & C3+ NGL mix	360	51.3%	185
Empress Gas Liquids Straddle Plant (3)	C2 & C3+ NGL mix	1,100	12.2%	134
Golden Spike Gas Plant	C2+NGL mix	40	100.0%	40
Villeneuve Ethane Extraction Plant	C2+NGL mix	40	100.0%	40
Fort Saskatchewan Ethane Extraction Plant	C2+NGL mix	35	100.0%	35
		1,575		434

Note:

(1) *Propane, butane and pentanes-plus ("C3") and a mixture of ethane and other natural gas liquids ("NGL").*

(2) *Ethane ("C2") and a mixture of other NGL's.*

(3) *Operated by ATCO Midstream.*

ATCO Midstream owns or has a joint venture interest in eight natural gas processing plants, five of which it operates, three compression facilities, all of which it operates, and approximately 1,000 km of field gathering lines. Natural gas production from the producing properties connected to ATCO Midstream's natural gas gathering systems is processed by ATCO Midstream and either transported for a fee or purchased and sold under contracts with third parties.

ATCO Midstream's natural gas processing plants with plant capacity ratings are shown below:

Facility	Plant Capacity (Mmcf/day)	Operator
Carbondale	55	Yes
Cranberry / Chinchaga Complex	124	No
Golden Spike	65	Yes
Nottingham Gas Plant	13	No
Puskwaskau Gas Plant	21	No
Watelet Gas Plant	21	Yes
West Pembina Gas Plant	145	Yes
Widewater Gas Plant	7	Yes
	451	

ATCO Midstream has an agreement for natural gas storage capacity at ATCO Gas' Carbon natural gas storage facility in Alberta. ATCO Midstream utilizes this capacity to provide storage services to third parties.

Technical Facilities Management

ATCO Frontec, through its own operations and through a number of joint ventures, provides project management and technical services for customers in the industrial, defence, telecommunications and transportation sectors. Activities include the operation and maintenance of the Alaska Radar System, the Solid State Phased Array Radar System and various remote sites for Northwestel Inc. in northern Canada. ATCO Frontec provides construction, site support and technical support for NATO in Afghanistan, Pakistan and eastern Europe. ATCO Frontec also provides airport operation and maintenance, security, facilities management, bulk fuel storage and distribution and a wide variety of services and business activities in various locations throughout Canada and the world.

ATCO Frontec and Pan Arctic Inuit Logistics Corporation ("Pan Arctic") have a contract with the Government of Canada, until September 2006, to operate and maintain the North Warning System. The Government of Canada has an option to extend the contract until 2011. Nasittuq Corporation, a corporation jointly owned by ATCO Frontec and Pan Arctic, operates as agent for the purposes of the contract.

Technologies

ATCO I-Tek is engaged in the development, operation and support of information systems and technologies.

ATCO I-Tek Business Services provides billing services, payment processing, credit, collection and call centre services to its clients. ATCO I-Tek Business Services currently provides such services to DEML for its regulated retail and competitive energy supply businesses in Alberta. In addition, ATCO I-Tek Business Services also supplies distribution-related billing and customer care services to ATCO Gas and ATCO Electric.

DEML has entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek Business Services to provide billing and call centre services to ensure continued quality customer service. DEML has the ability to terminate this contract after the fifth anniversary upon immediate payment of termination fees which decline over the remaining term of the contract. Based upon current customer counts and service levels and a 10 year contract, revenues are estimated to be between $400-$500 million over the term of the contract.

ASHCOR Technologies is engaged in the sale of fly ash and other combustion byproducts produced in coal-fired electrical generating plants.

ATCO Travel is engaged in the sale of travel services to both business and consumer sectors. ATCO Travel is one of the largest independent travel agencies in western Canada.

The Corporation owns a 50% interest in the shares of Genics, a manufacturer of wood preservation products.

BUSINESS RISKS

The business risks section on pages 20 to 24 of the Corporation's Management's Discussion and Analysis ("MD&A") is hereby incorporated by reference and is available at www.sedar.com.

GOVERNMENT REGULATION

Under Alberta legislation, owners of public, electric or gas utilities are required to obtain AEUB approval prior to issuing securities. CU and CU Inc. are considered to be owners, but have obtained from the AEUB orders which exempt them from this requirement.

The utility operations of the Corporation in Alberta (ATCO Gas, ATCO Electric, ATCO Pipelines and CU Water) are subject to the jurisdiction of the AEUB which, among other things, is vested with broad general powers of supervision with respect to the construction and operation of electric energy and natural gas facilities within the Province and broad powers of regulation in respect of rates charged for the delivery of electric energy, natural gas and water.

The AEUB approves customer rates based on anticipated energy deliveries as well as the revenue required to recover estimated costs of service, including a fair return on rate base, estimated operating expenses, depreciation and taxes, all in respect of a future test period. Energy deliveries are based on a forecast of economic and business conditions and, in the case of natural gas utility operations, normal temperature which is defined as the average temperature for the previous 20 years.

Rate base consists of the depreciated cost of utility assets and an allowance for working capital. Return on rate base is designed to meet the cost of interest on long term debt and dividends on preferred shares and to provide the common shareholders with a reasonable opportunity to earn a fair return on their investment. The determination of a fair return to the common shareholders involves an assessment by the AEUB of many factors, including returns on alternative investment opportunities of comparable risk and the level of return which will enable a utility to attract the necessary capital to fund its operations.

The EUA and the GUA grant the AEUB specific authority to approve customer rates that provide incentives for efficiencies that result in cost savings or other benefits that can be shared in an equitable manner between a utility and its customers. Final determination of such customer rates requires the approval of the AEUB.

The regulated operations of the Corporation in the Yukon Territory (YECL) and the Northwest Territories (NUY and NLD) are subject to regulation similar to that in effect in Alberta by regulatory authorities in those jurisdictions.

Particulars of the most recent final decisions made by the AEUB respecting general rate applications or negotiated settlements filed by the principal regulated subsidiaries of the Corporation are as follows:

	Year	Date of Decision (1)	Mid-Year Rate Base ($ Millions)		Rate of Return on Common Equity (2) (%)		Common Equity Ratio (3) (%)	
ATCO Electric								
Transmission................	2003	Oct. 02/03	672.0		9.40		32.0	
	2004	Oct. 02/03	748.0		9.60	(4)	33.0	(4)
Distribution..................	2003	Oct. 02/03	558.5		9.40		35.0	
	2004	Oct. 02/03	584.8		9.60	(4)	37.0	(4)
ATCO Pipelines								
North............................	2003	Dec. 02/03	351.8		9.50		43.5	
	2004	Dec. 02/03	355.2		9.60	(4)	43.0	(4)
South............................	2003	Dec. 02/03	144.8		9.50		43.5	
	2004	Dec. 02/03	147.6		9.60	(4)	43.0	(4)
ATCO Gas								
North............................	2005	Jan. 27/06	513.1	(5)	9.50	(6)	38.0	(6)
	2006	Jan. 27/06	536.2	(5)	8.93	(6)	38.0	(6)
	2007	Jan. 27/06	562.8	(5)	8.93	(6)	38.0	(6)
South............................	2005	Jan. 27/06	555.1	(5)	9.50	(6)	38.0	(6)
	2006	Jan. 27/06	533.2	(5)	8.93	(6)	38.0	(6)
	2007	Jan. 27/06	549.9	(5)	8.93	(6)	38.0	(6)

Notes:

(1) *The information shown reflects the most recent amending or varying orders issued subsequent to the original date of decision.*

(2) *Common equity rate of return is the rate of return on the portion of rate base considered to be financed by common equity.*

(3) *The common equity ratio is the percentage of rate base considered to be financed by common equity.*

(4) *The rate of return on common equity and common equity ratio for 2004 for ATCO Electric and ATCO Pipelines was determined by the AEUB's generic cost of capital decision dated July 2, 2004.*

(5) *Amounts shown for mid-year rate base are based on the AEUB 2005, 2006, and 2007 general rate application decision issued in January 2006. These amounts will be updated based on the compliance filing due to the AEUB on March 17, 2006.*

(6) *The common equity ratios for 2005 – 2007 for ATCO Gas were determined by the AEUB's generic cost of capital decision dated July 2, 2004. The 2005, 2006, 2007 general rate application decision issued by the AEUB in January 2006 approved a return on common equity as determined by the AEUB's standardized rate of return methodology. The return on common equity is 9.5% in 2005, 8.93% in 2006, and is yet to be determined for 2007 and as such the 2007 rate of return on common equity is a placeholder.*

Generic Cost of Capital

In July 2004, the AEUB issued its generic cost of capital decision. The decision established a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity based upon a return of 9.60% on common equity. 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. This adjustment mechanism is the same as the National Energy Board uses in determining its formula based rate of return. The AEUB will undertake a review of this mechanism for the year 2009 or if the rate of return resulting from the formula is less than 7.6% or greater than 11.6%. The AEUB also noted that any party, at any time, could petition for a review of the adjustment formula if that party can demonstrate a material change in facts or circumstances.

The decision also established the appropriate capital structure for each utility regulated by the AEUB. The AEUB 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.

In November 2004, the AEUB announced a generic return on common equity of 9.50% for 2005 and in November 2005 announced a generic return on common equity of 8.93% for 2006. In January 2006, the AEUB clarified that the generic return on equity determined in accordance with the generic cost of capital decision should apply to each year of the test period in the companies' 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.

Gas Utilities Act

Under the GUA, the customers served by ATCO Gas have the choice of purchasing their natural gas supplies at a regulated rate provided by DEML or directly from retailers, subject to certain conditions.

As a result of the Transfer of the Retail Energy Supply Businesses to DEML in May 2004, ATCO Gas is no longer involved in arranging for the supply and sale of natural gas to customers, but continues to own the assets and provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return.

Electric Utilities Act

The EUA provides the framework for a new structure in Alberta's electric utility industry and introduces competition into the electric utility business. As of January 1, 2001, new generation was completely deregulated and retail competition was introduced. In August 2002, the Government of Alberta announced further changes to utility legislation in order to improve the environment for retail competition in the Province. Amendments to the EUA and GUA received Royal Assent in March 2003 and were proclaimed in force in June 2003. These changes were designed to bring customer choice for both gas and electricity into closer alignment, as well as to move towards consistent regulatory treatment of investor-owned and municipally-owned utilities.

ATCO Electric continues to have the responsibility to provide the regulated rate tariff to the residential, farm and small commercial customers in its designated service area who do not choose an energy retailer. As a result of the Transfer of the Retail Energy Supply Businesses to DEML in May 2004, ATCO Electric is no longer involved in arranging for the supply and sale of electricity to customers and is therefore no longer at risk for electric energy supply. ATCO Electric continues to own the assets and provide transmission and distribution services under AEUB approved rates that provide for a recovery of the cost of service, including a fair return on rate base.

It is anticipated that ATCO Electric's transmission and distribution activities will continue to be regulated by the AEUB.

New Generation (ATCO Power)

Under the EUA, generation assets constructed after December 31, 1995, are not considered part of utility operations and rates are not regulated by the AEUB. All owners of new and existing generating units must sell their surplus electric energy through the Alberta Power Pool.

Existing Generation (Alberta Power (2000))

The EUA provided for the equalization of costs of "existing generation" that was in service at December 31, 1995. On January 1, 2001, existing generation became subject to legislatively mandated PPA's approved by the AEUB. 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 expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the life of the related generating plant and December 31, 2020.

Transmission

Under the EUA, separate wholesale tariffs for transmission must be approved by the AEUB. The transmission tariffs allow any owner of a generating unit to have access to the transmission system in Alberta and thus facilitate the sale of its power. The same transmission tariff is charged to each distribution utility or customer directly connected to the transmission system regardless of location.

The equalization of transmission costs is achieved by having each owner of transmission facilities charge its costs to the Alberta Power Pool. The Alberta Power Pool then aggregates these costs and charges a common transmission rate to all who use the transmission system.

The Alberta Power Pool has developed and approved rules as mandated in the Transmission Regulation enacted by the Government of Alberta in 2004. These rules direct that new transmission projects will be assigned to the Transmission Facility Owners based on the service areas of the distribution companies they have been historically affiliated with. Ownership of facilities will change at service area boundaries except where, in the opinion of the Alberta Power Pool, only a small portion of the project is in another service area. All expansions of existing facilities will be assigned to the existing owner.

Distribution

Under the EUA, separate retail rates for distribution must be approved by the AEUB. Costs of distribution are not equalized. The distribution utility provides the distribution services for all customers under AEUB approved tariffs which provide for the recovery of the cost of service, including a fair return on rate base.

Environmental Protection

The Corporation's operating subsidiaries and the industries in which they operate are subject to extensive federal, provincial and local environmental protection laws concerning emissions to the air, discharges to surface and subsurface waters, land use activities and the handling, manufacturing, processing, use, emission and disposal of materials and waste products. In Alberta, protection of the environment is generally governed by the Alberta Environmental Protection and Enhancement Act. The operating subsidiaries have obtained or are obtaining all permits and licenses required by law to carry on their operations.

The Corporation's operating subsidiaries are committed to preserving and protecting the environment and minimizing the discharge of harmful materials into the environment in accordance with environmental protection laws and regulations. Nevertheless, some risk of unintentional violation of environmental protection laws and the resulting liability to the Corporation's operating subsidiaries is inherent in particular operations of these subsidiaries, as it is with other companies engaged in similar businesses. There can be no assurance that material costs and liabilities will not be incurred. To mitigate these costs, the Corporation carries insurance for the operating subsidiaries against third party claims for bodily injury and property damage arising from a sudden and accidental event or occurrence resulting from an unexpected release of pollutants or contaminants.

The Corporation's operating subsidiaries do not expect that environmental protection laws and regulations will affect them differently from other companies in the industries in which they operate. Specifically identifiable expenditures for pollution abatement and control were approximately $24.3 million in 2005 and are estimated to be $29.6 million in 2006. Costs of compliance with existing laws and regulations are not expected to have a material impact on the earnings of the Corporation or the competitive position of the operating subsidiaries.

DESCRIPTION OF CAPITAL STRUCTURE

Two for One Share Split

In July 2005, the Corporation's Board of Directors approved a two-for-one share split of the outstanding Class A and Class B Shares. The share split took the form of a stock dividend whereby share owners received one additional Class A Share for each Class A Share held as of the record date and one additional Class B Share for each Class B Share held as of the record date. The stock dividend was paid on September 15, 2005 to share owners of record at the close of business on August 29, 2005. All share, stock option and per share amounts have been retroactively restated to reflect this share split.

Share Capital

The authorized share capital of the Corporation consists of 150,000 Series Preferred Shares issuable in series, an unlimited number of Series Second Preferred Shares issuable in series and an unlimited number of Class A Shares and Class B Shares. At February 21, 2006, the Corporation had outstanding:

- no Series Preferred Shares;
- nine series of Series Second Preferred Shares totaling 25,460,105 shares ($636.5 million);
- 82,939,286 Class A Shares; and
- 44,016,284 Class B Shares.

Series Preferred Shares

The Series Preferred Shares are entitled, in priority to the Series Second Preferred Shares and the Class A Shares and Class B Shares, to fixed cumulative preferential cash dividends and, in the event of the liquidation, dissolution or winding-up of the Corporation, or other distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, to the amount paid up thereon and accrued and unpaid dividends and, if such action is voluntary, the premiums payable on redemption, if any.

The Series Preferred Shares are subject to redemption on 30 days' notice and are non-voting except upon the failure of the Corporation to pay dividends on any such shares for a period of 18 months, in which case the holders of all such shares are entitled to one vote per share and to elect at meetings of shareholders at which directors are elected just under one-half of the directors of the Corporation.

The provisions attaching to the Series Preferred Shares stipulate that no shares ranking junior to the Series Preferred Shares may be retired unless all dividends then payable on the Series Preferred Shares shall have been declared and paid.

Two series of Series Preferred Shares aggregating 65,000 shares have been designated and issued to date, all of which have been redeemed and cancelled.

Series Second Preferred Shares

An unlimited number of Series Second Preferred Shares are issuable in series, each series consisting of such number of shares and having such provisions attaching thereto as may be determined by the directors. The Series Second Preferred Shares as a class have, among others, provisions to the following effect:

(i) The Series Second Preferred Shares rank junior to the Series Preferred Shares but are, with respect to priority in payment of dividends and in the distribution of assets in the event of liquidation, dissolution or winding up of the Corporation, entitled to preference over the Class A Shares and the Class B Shares and any other shares of the Corporation ranking junior to the Series Second Preferred Shares. The Series Second Preferred Shares may also be given such other preference over the Class A Shares and the Class B Shares and any other junior shares as may be determined for any series authorized to be issued.

(ii) The Series Second Preferred Shares of each series rank equally with the Series Second Preferred Shares of every other series with respect to priority in payment of dividends and in the distribution of assets in the event of liquidation, dissolution or winding up of the Corporation.

(iii) The holders of the Series Second Preferred Shares are not entitled as such (except as provided in any series) to any voting rights nor to receive notice of or to attend shareholders' meetings unless dividends on the Series Second Preferred Shares of any series are in arrears to the extent of eight quarterly dividends or four half-yearly dividends, as the case may be, whether or not consecutive. Until all arrears of dividends have been paid, such holders will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class of shares) and to one vote in respect of each Series Second Preferred Share held.

The following Series Second Preferred Shares are currently outstanding:

	Stated Value (dollars)	Redemption Dates (1)	2005 Shares	2005 Amount (millions of dollars)
Cumulative Redeemable Second Preferred Shares				
5.9% Series Q	$25.00	Open	2,277,675	56.9
5.3% Series R	$25.00	Open	2,146,730	53.7
6.6% Series S	$25.00	Open	635,700	15.9
5.8% Series W (2)	$25.00	See below	6,000,000	150.0
6.0% Series X (3)	$25.00	See below	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares				
5.05% Series O (4)	$25.00	December 2, 2006	1,600,000	40.0
5.05% Series T (4)	$25.00	December 2, 2006	1,600,000	40.0
5.05% Series U (4)	$25.00	December 2, 2006	800,000	20.0
5.25% Series V (4)	$25.00	October 3, 2007	4,400,000	110.0
				636.5

Notes:

(1) The preferred shares, except for the Series W and X, are redeemable on the dates specified above at the option of the Corporation at the stated value per share plus accrued and unpaid dividends.

(2) The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value per share 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.

(3) The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value per share 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

(4) 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 the Corporation and the owners of the shares.

Class A Shares and Class B Shares

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

If a take-over bid is made for the Class B Shares, which would result in the offeror owning more than 50% of the outstanding Class B Shares and which would constitute a change in control of the Corporation, owners of Class A Shares are entitled, for the duration of the bid, to exchange their Class A Shares for Class B Shares and to tender such Class B 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 Shares are entitled to exchange their shares for Class B Shares of the Corporation if ATCO Ltd., the present controlling share owner of the Corporation, ceases to own or control, directly or indirectly, more than 20,000,000 of the issued and outstanding

Class B Shares of the Corporation. In either case, each Class A Share is exchangeable for one Class B Share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

DIVIDENDS

Cash dividends declared during the past three years for all series and classes of preferred and common shares are as follows:

	Year Ended December 31		
	2005	2004	2003
		($ per share)	
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O	1.26	1.26	1.26
Series Q	1.48	1.48	1.48
Series R	1.33	1.33	1.33
Series S	1.65	1.65	1.65
Series T	1.26	1.26	1.26
Series U	1.26	1.26	1.26
Series V	1.31	1.31	1.31
Series W (1)	1.45	1.45	1.44
Series X (2)	1.50	1.50	0.93
Class A and Class B Shares	1.10	1.06	1.02

Notes:
(1) *Issued December 3, 2002.*
(2) *Issued April 17, 2003.*

It is the policy of the Corporation to pay dividends quarterly on its Class A and Class B Shares. In 2005, the Corporation increased the dividends on Class A and Class B Shares by $0.04 per share, the same increase as in 2004. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. For the first quarter of 2006, the quarterly dividend payment has been increased by $0.01 to $0.285 per share. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

CREDIT RATINGS

The current credit ratings on the Corporation's and CU Inc.'s securities are as follows:

	DBRS (1)	S&P (2)
Canadian Utilities Limited:		
Debentures	A	A-
Commercial paper	R-1 (low)	A-1 (mid)
Preferred Shares:		
Obligations of CU Inc. (3)	Pfd-2 (high)	P-2 (high)
Obligations of CU	Pfd-2	P-2 (high)
CU Inc.:		
Debentures	A (high)	A
Commercial paper	R-1 (low)	A-1 (mid)
Preferred Shares	Pfd-2 (high)	Not rated

Notes:

(1) Dominion Bond Rating Service Limited ("DBRS") maintains a stable trend on the above securities.

(2) Standard and Poor's ("S&P") maintains a stable trend on the above securities.

(3) Refers to the Cumulative Redeemable Second Preferred Shares Series Q, R and S and the Perpetual Cumulative Second Preferred Shares Series U and V which were issued by Canadian Utilities Limited prior to the creation of CU Inc. on March 12, 1999.

Long Term Debt Credit Ratings

An A rating by DBRS is the third highest of ten categories. Long term debt rated A is of satisfactory credit quality. Protection of interest and principal is still substantial but the degree of strength is less than that of AA rated entities. While A is a respectable rating, entities in this category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher-rated securities. "High" and "low" grades may be used to indicate the relative standing of a credit within a particular rating category.

An A rating by S&P is the third highest of eleven categories. Obligations rated A by S&P are somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories, however, the obligor's capacity to meet its financial commitment on the obligations is still strong. The addition of a plus or minus sign shows relative standing within the rating categories.

Commercial Paper Credit Ratings

An R-1 (low) rating by DBRS is the third highest of ten categories and is granted to short-term debt of satisfactory credit quality. The overall strength and outlook for key liquidity, debt, and profitability ratios is not normally as favourable as with higher rating categories, but these considerations are still respectable. Any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry.

An A-1 (mid) rating by S&P is the second highest of eight categories in its Canadian commercial paper ratings scale and is granted where the obligor's capacity to meet its financial commitment on the obligation is strong.

Preferred Share Credit Ratings

A Pfd-2 rating by DBRS is the second highest of six categories granted by DBRS for preferred shares and is granted to companies presenting satisfactory credit quality where protection of dividends and principal is still substantial, but earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies. "High", and "low" grades may be used to indicate the relative standing of a credit within a particular rating category.

A P-2 rating by S&P is the second highest of eight categories S&P uses in its Canadian preferred share rating scale and is granted where the obligor's capacity to meet its financial commitments is considered adequate, but is more subject to adverse economic conditions than higher rating categories. "High", "mid" and "low" grades may be used to indicate the relative standing of a credit within a particular rating category.

Credit Ratings Generally

A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

DIRECTORS AND EXECUTIVE OFFICERS

Set out below is information with respect to the directors and officers of the Corporation.

Name, Province or State and Country of Residence	Position	Principal Occupation	Periods Served as a Director of the Corporation
R.T. Booth (4) Alberta, Canada	Director	Partner, Bennett Jones LLP (barristers and solicitors)	1998 to date
W.L. Britton, Q.C. (2) Alberta, Canada	Director & Vice Chairman of the Board	Vice Chairman of the Board, Canadian Utilities Limited and ATCO Ltd.	1980 to date
D.T. Davis Alberta, Canada	Vice President, Internal Audit & Risk Management	Vice President, Internal Audit & Risk Management, Canadian Utilities Limited and ATCO Ltd.	
B.P. Drummond (2) (5) Quebec, Canada	Director	Corporate Director	1997 to date
B.K. French (3) (4) Alberta, Canada	Director	President, Karusel Management Ltd. (property management and management consultants)	1981 to date
I.D. Hargrave Alberta, Canada	Vice President, Project Development	Vice President, Project Development, Canadian Utilities Limited and ATCO Ltd.	
L.A. Heathcott (5) Alberta, Canada	Director	President, Spruce Meadows (international show jumping venue)	2000 to date
E.M. Kiefer Alberta, Canada	Vice President, Human Resources	Vice President, Human Resources, Canadian Utilities Limited and ATCO Ltd.	
S.W. Kiefer Alberta, Canada	Managing Director, Utilities & Chief Information Officer	Managing Director, Utilities & Chief Information Officer, Canadian Utilities Limited and ATCO Ltd.	
C.S. McConnell Alberta, Canada	Treasurer	Treasurer, Canadian Utilities Limited and ATCO Ltd.	
H.M. Neldner (2) (3) (4) (5) Alberta, Canada	Director	Corporate Director	1991 to date
M.R.P. Rayfield (5) Ontario, Canada	Director	Vice Chairman, Investment & Corporate Banking, BMO Nesbitt Burns	2004 to date

Name, Province or State and Country of Residence	Position	Principal Occupation	Periods Served as a Director of the Corporation
M.M. Shaw Alberta, Canada	Managing Director, Global Enterprises	Managing Director, Global Enterprises, Canadian Utilities Limited and ATCO Ltd.	
J.W. Simpson (2) (3) (4) California, U.S.A.	Lead Director	Corporate Director	2004 to date
N.C. Southern Alberta, Canada	Director, President & Chief Executive Officer	President & Chief Executive Officer, Canadian Utilities Limited and ATCO Ltd.	1990 to date
R. D. Southern, C.B.E., O.C., LL.D. (6) Alberta, Canada	Director & Chairman of the Board	Chairman of the Board, Canadian Utilities Limited and ATCO Ltd.	1977 to 1979 1980 to date
P. Spruin Alberta, Canada	Corporate Secretary	Corporate Secretary, Canadian Utilities Limited and ATCO Ltd.	
K.M. Watson Alberta, Canada	Senior Vice President & Chief Financial Officer	Senior Vice President & Chief Financial Officer, Canadian Utilities Limited and ATCO Ltd.	
S.R. Werth Alberta, Canada	Senior Vice President & Chief Administration Officer	Senior Vice President & Chief Administration Officer, Canadian Utilities Limited and ATCO Ltd.	
C.W. Wilson (3) (4) Colorado, U.S.A.	Director	Corporate Director	2000 to date
P.G. Wright Alberta, Canada	Vice President, Finance & Controller	Vice President, Finance & Controller, Canadian Utilities Limited and ATCO Ltd.	

Notes:

(1) Each director holds office until the close of the annual meeting of shareholders of the Corporation.
(2) Member of the Corporate Governance – Nomination, Compensation and Succession Committee.
(3) Member of the Audit Committee.
(4) Member of the Risk Review Committee.
(5) Member of the Pension Fund Committee.
(6) R.D. Southern was a director of Canadian Airlines Corporation when it filed for protection under the Companies' Creditors Arrangement Act on March 24, 2000.

All of the directors and officers have been engaged for the last five years in the indicated principal occupations, or in other capacities with the companies or firms referred to, or with affiliates or predecessors thereof, with the exception of Mr. J.W. Simpson who was Vice President, Middle East & North Africa, Business Development, Chevron Texaco Corporation.

SHAREHOLDINGS OF DIRECTORS AND EXECUTIVE OFFICERS

At December 31, 2005, the directors and officers of the Corporation, as a group, beneficially owned, directly or indirectly (via corporate holdings or otherwise), or exercised control or direction over approximately 74.6% of the outstanding Class B common shares of the Corporation.

AUDIT COMMITTEE

Audit Committee Charter

Canadian Utilities Limited Audit Committee Mandate

Purpose

The purpose of this Mandate is to establish the terms of reference of the Audit Committee of the Corporation. The Audit Committee is appointed by the Board of Directors of the Corporation. The Audit Committee is responsible for contributing to the effective stewardship of the Corporation by assisting the Board of Directors in fulfilling its oversight of:

- the integrity of the Corporation's financial statements;
- the Corporation's compliance with applicable legal and regulatory requirements;
- the independence, qualifications and appointment of the Corporation's external auditor; and
- the performance of the Corporation's internal audit function and external auditors.

Composition

The Board of Directors shall elect annually from among its members an Audit Committee comprised of not less than 3 directors. Each member of the Audit Committee must be:

- a director of the Corporation;
- independent (within the meaning of sections 1.4 and 1.5 of Multilateral Instrument 52-110 *Audit Committees*); and
- financially literate.

In order to be considered to be an independent director for the purposes of membership on the Audit Committee, a director must have been determined by the Board of Directors to be independent in accordance with all applicable regulatory requirements.

The Board of Directors will appoint one member of the Audit Committee as Chairman. Any member of the Audit Committee may be removed or replaced at any time by the Board of Directors, and a member shall cease to be a member of the Audit Committee upon ceasing to be independent.

Meetings

The Audit Committee shall meet at least four times per year and whenever deemed necessary by the Chairman of the Audit Committee or at the request of an Audit Committee member or the Corporation's external or internal auditors. The Audit Committee Chairman shall prepare and/or approve an agenda in advance of each meeting. Reasonable notification of meetings, which may be held in person, by telephone or other communication device, shall be sent to the members of the Audit Committee, the external auditors and any additional attendees as determined by the Chairman. The external auditor has the right to appear before and be heard at any meeting of the Audit Committee. Upon the request of the external auditor, the Chairman of the Audit Committee shall convene a meeting of the Audit Committee to consider any matters which the auditor believes should be brought to the attention of the directors or shareholders of the Corporation. Meetings will be scheduled to permit timely review of Audit Committee materials. A majority of the Audit Committee will constitute a quorum. Minutes of each meeting will be prepared by the person designated by the Audit Committee to act as secretary and will be kept by the Corporate Secretarial Department.

Reporting

The Audit Committee shall report to the Board of Directors of the Corporation on such matters and questions relating to the financial position of the Corporation as the Board of Directors may from time to time refer to the Audit Committee. A summary of all meetings will be provided to the Board of Directors by the Audit Committee Chairman. Supporting schedules and information reviewed by the Audit Committee will be available for examination by any director upon request. The external auditors and the Vice President, Internal Audit and Risk Management shall report directly to the Audit Committee. The Audit Committee is expected to maintain free and open communication with the Corporation's external auditors, internal auditors and management. This communication shall include private sessions, at least annually, with each of these parties.

Responsibilities

The Audit Committee relies on the expertise and knowledge of management, and the internal and external auditors in carrying out its oversight responsibilities. Management of the Corporation is responsible for determining that the Corporation's financial statements are complete, accurate and in accordance with generally accepted accounting principles. The external auditors are responsible for auditing the Corporation's financial statements.

The Audit Committee shall have the power to conduct or authorize investigations into any matters within the Audit Committee's scope of responsibilities. The Audit Committee shall be empowered to retain independent counsel, accountants or other outside advisors as it determines necessary to permit it to carry out its duties.

The Audit Committee shall:

- Recommend to the Board of Directors:

  (a) The external auditors to be nominated for the purpose of preparing or issuing an audit report or performing other audit, review or attestation services for the Corporation;
  (b) The compensation of the external auditors; and
  (c) The approval of the Corporation's annual financial statements, AIF and MD&A.

- Be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attestation services for the Corporation, including the resolution of disagreements between management and the external auditors regarding financial reporting.

- Pre-approve all non-audit services to be provided to the Corporation or its subsidiaries by the external auditors of the Corporation or its subsidiaries. The Audit Committee may delegate to one or more of its members the authority to grant pre-approvals provided that any pre-approvals so granted are presented in writing to the Audit Committee at the next regularly scheduled meeting. The Audit Committee will ensure that relevant policies and procedures are in place to manage this process and comply with all applicable regulatory requirements.

- Review the Corporation's annual and interim financial statements, AIF, MD&A and annual and interim earnings press releases before this information is publicly disclosed.

- As delegated by the Board of Directors, approve the interim financial statements, MD&A and earnings press releases before this information is publicly disclosed.

- Be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, and periodically assess the adequacy of such procedures. This would include an annual review of the Corporation Disclosure Policy.

- Establish procedures for:

  (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, auditing matters, fraud or theft; and
  (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters, fraud or theft.

- Ensure the Corporation has implemented appropriate systems of internal control over financial reporting and that these systems are operating effectively;

- Ensure the internal audit function has been effectively carried out and the internal auditors have adequate resources;

- Review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation;

- Review and reassess annually the adequacy of the Audit Committee's responsibilities and recommend any proposed changes to the Board of Directors for approval.

The members of the Audit Committee, for the purpose of performing their duties, have the right to inspect all the books and records of the Corporation and its subsidiary entities and to discuss such books and records in any manner relating to the financial position of the Corporation and its subsidiary entities with the officers, employees and external auditors of the Corporation and its subsidiary entities.

The Audit Committee will inquire into any other matters referred to it by the Board of Directors.

Composition of the Audit Committee

The following are members of the Corporation's Audit Committee. All members are independent and financially literate:

- B.K. French
- H.M. Neldner
- J.W. Simpson
- C.W. Wilson

Relevant Education and Experience

B.K. French	Mr. French has a Bachelor of Commerce with an Accounting and Finance Major and is a Chartered Accountant. Mr. French was engaged in public practice for 25 years.
H.M. Neldner	Mr. Neldner has a Bachelor of Commerce (Finance). Mr. Neldner held various senior management positions in accounting and finance including General Accountant, Comptroller, Vice President Finance and President & CEO with Alberta Government Telephones and Telus Corporation.
J.W. Simpson	Mr. Simpson graduated from an Executive Program at M.I.T's Sloan School of Business. During Mr. Simpson's career at Chevron Corporation various financial positions reported to him. In his capacity as General Manager the accounting department reported to him and as President of Chevron Canada the Vice President Finance directly reported to Mr. Simpson. In addition, Mr. Simpson was Chairman of the Internal Audit Committee of Chevron Canada.
C.W. Wilson	Mr. Wilson has an understanding of the accounting principles of Canadian Utilities Limited. In addition, Mr. Wilson previously supervised a CFO directly for a seven year period as President & CEO of Shell Canada Ltd.

Reliance on Certain Exemptions

The Corporation did not rely on any exemptions from the Audit Committee requirements of Canadian Securities Legislation.

Audit Committee Oversight

Since January 1, 2005, all recommendations of the Audit Committee to nominate or compensate an external auditor were adopted by the Board of Directors.

Pre-Approval Policies and Procedures

The Audit Committee and the Board of Directors of the Corporation have adopted a policy for approval of external auditor services. The policy prohibits the external auditor from providing specified services to the Corporation and its subsidiaries.

The engagement of the external auditor for a range of services defined in the policy has been pre-approved by the Audit Committee. If an engagement of the external auditor is contemplated for a particular service that is neither prohibited nor covered under the range of pre-approved services, such engagement must be pre-approved. The Audit Committee has delegated the authority to grant such pre-approval to the Chairman of the Audit Committee.

Services provided by the external auditor are subject to an engagement letter. The policy mandates that the Audit Committee receive regular reports of all new pre-approved engagements of the external auditor.

External Auditor Service Fees

The aggregate fees incurred by the Corporation and its subsidiaries for professional services provided by PricewaterhouseCoopers LLP for each of the past two years were as follows:

	2005	**2004**
	($Millions)	
Audit (1)	1.3	1.3
Audit Related (2)	0.1	0.1
Tax (3)	0.3	0.1
Total	1.7	1.5

Notes:

(1) Audit fees include the aggregate professional fees paid to the external auditor for the audit of the annual consolidated financial statements and other regulatory audits and filings.

(2) Audit-related fees include the aggregate fees paid to the external auditor for services related to special purpose audits and the audit services including consultations regarding financial reporting and accounting standards.

(3) Tax fees include the aggregate fees paid to the external auditor for tax compliance, tax advice, tax planning and advisory services relating to the preparation of corporate tax, capital tax and sales tax returns.

MARKETS FOR THE SECURITIES OF THE CORPORATION

The Corporation's Class A shares, Class B shares and Cumulative Redeemable Second Preferred Shares, Series Q, R, S, W and X are listed on the Toronto Stock Exchange. The Perpetual Cumulative Second Preferred Shares Series O, T, U and V are not listed.

The following table sets forth the high and low prices and the volume of shares traded on the Toronto Stock Exchange during 2005 for the Corporation's listed shares.

	Class A Shares			Class B Shares		
	High $	Low $	Volume	High $	Low $	Volume
January	30.88	29.76	774,088	31.75	29.94	20,182
February	31.50	29.55	909,992	31.03	29.63	37,996
March	32.46	30.03	996,474	32.14	30.15	23,612
April	32.08	30.00	1,328,082	31.73	30.25	29,180
May	32.30	29.98	1,953,134	32.50	30.56	22,582
June	35.00	31.76	1,144,954	34.88	31.99	24,400
July	35.95	33.91	711,628	35.85	34.40	26,744
August	38.50	34.59	1,072,907	38.50	34.56	29,496
September	41.48	37.30	1,093,951	41.00	37.57	29,309
October	41.23	36.00	1,163,031	41.25	38.00	27,595
November	45.40	39.40	1,316,399	45.52	39.40	25,581
December	46.20	41.00	1,101,755	45.82	41.56	30,643

	Cumulative Redeemable Second Preferred Shares					
	Series Q			Series R		
	High $	Low $	Volume	High $	Low $	Volume
January	26.95	25.75	10,750	25.90	25.20	19,872
February	26.25	25.40	36,500	25.50	25.25	3,425
March	27.00	25.01	15,800	25.35	24.65	27,500
April	26.00	25.01	6,850	25.15	24.90	23,325
May	25.70	25.01	1,500	25.30	24.81	29,230
June	25.85	25.11	195,760	25.40	25.00	7,725
July	25.90	25.31	9,930	25.34	25.02	4,620
August	25.55	24.95	2,650	25.45	25.00	16,300
September	25.75	25.03	17,114	25.45	25.05	6,725
October	25.90	25.15	7,994	25.35	25.01	9,350
November	25.75	25.04	13,235	25.19	24.77	7,790
December	25.99	25.30	7,895	25.50	25.00	29,390

	Cumulative Redeemable Second Preferred Shares					
	Series S			Series W		
	High $	Low $	Volume	High $	Low $	Volume
January	27.80	26.00	3,300	27.49	26.81	45,501
February	-	-	-	27.39	26.80	56,115
March	-	-	-	27.15	26.02	61,576
April	27.25	27.00	1,890	26.39	25.85	35,864
May	27.50	26.65	1,200	26.93	26.06	1,271,737
June	27.53	26.70	1,300	27.17	26.26	47,674
July	27.10	27.10	600	27.19	26.22	39,725
August	-	-	-	26.83	26.03	48,826
September	28.25	27.10	17,460	26.94	26.35	40,954
October	27.50	27.50	420	26.81	26.30	29,873
November	27.50	26.60	2,900	27.95	26.50	55,788
December	27.50	27.00	2,000	27.67	26.71	43,595

	Cumulative Redeemable Second Preferred Shares		
	Series X		
	High $	Low $	Volume
January	28.10	27.20	43,652
February	27.60	27.11	48,763
March	27.35	26.01	45,505
April	26.92	26.02	45,932
May	27.50	26.45	1,239,969
June	27.34	26.81	43,502
July	27.33	26.75	47,417
August	27.30	26.55	39,448
September	27.20	26.23	35,610
October	27.15	26.36	47,832
November	27.64	26.57	155,249
December	27.74	26.64	51,445

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Class A Shares, Class B Shares and Cumulative Redeemable Second Preferred Shares, Series Q, R, S, W and X preferred shares is CIBC Mellon Trust Company at its principal offices in Calgary, Vancouver, Toronto and Montreal. The transfer agent and registrar for the Perpetual Cumulative Second Preferred Shares Series O, T, U and V is the Corporation at its principal office in Calgary. The trustee and transfer agent for the debentures of the Corporation is CIBC Mellon Trust Company at its principal offices in Calgary, Vancouver, Toronto and Montreal.

EXPERTS

PricewaterhouseCooper's LLP has prepared the auditor's report with respect to the Corporation's annual financial statements. PricewaterhouseCooper's LLP is independent in accordance with the auditor's rules of professional conduct in Canada.

EMPLOYEE RELATIONS

At December 31, 2005, the Corporation and its joint ventures had the following number of employees:

	Number
Utilities	3,340
Global Enterprises	1,526
Power Generation	381
Other	81
Sub Total	5,328
Joint Ventures – Global Enterprises	895
Joint Ventures – Power Generation	253
Total	6,476

Approximately 3,700 employees are members of seven employee associations and nine unions and are covered by 26 collective agreements. Two of these agreements have expired and are under re-negotiation and the remaining 24 agreements expire over the period September 30, 2006 to September 30, 2010.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, is contained in the Corporation's Management Proxy Circular dated March 2, 2005. Additional financial information is provided in the Corporation's comparative financial statements and Management's Discussion and Analysis for the financial year ended December 31, 2005.

Information relating to ATCO Ltd. or CU Inc. may be obtained upon request from the Corporate Secretary of the respective corporation at 1400 ATCO Centre, 909 – 11th Avenue S.W., Calgary, Alberta T2R 1N6 (telephone (403) 292-7500 or fax (403) 292-7623). Corporate information is also available on the Corporation's website: www.canadian-utilities.com. Additional information relating to the Corporation may be found on SEDAR at www.sedar.com.

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED
An ATCO Company

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2005

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS ("MD&A")

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's unaudited consolidated interim financial statements for the three months ended December 31, 2005, and the audited consolidated financial statements for the year ended December 31, 2005. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

All quarterly information in this document is unaudited and is shaded to differentiate it from the annual information.

The common share capital of the Corporation consists of Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares").

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FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in the forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, this MD&A contains forward-looking statements pertaining to purchase obligations, planned capital expenditures, the impact of changes in government regulation and non-regulated generating capacity subject to long term contracts. The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of regulatory decisions, competitive factors in the industries in which the Corporation operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

CONTROLS AND PROCEDURES

As of December 31, 2005, the Corporation's management evaluated the effectiveness of the design and operation of its disclosure controls and procedures ("Disclosure Controls") as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO").

Disclosure Controls are procedures designed to ensure that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis, and is accumulated and communicated to the Corporation's management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

The Corporation's management, including the CEO and the CFO, does not expect that the Corporation's Disclosure Controls will prevent or detect all error and all fraud. Because of the inherent limitations in all control systems, an evaluation of controls can provide only reasonable, not absolute, assurance that all control issues and instances of fraud or error, if any, within the Corporation have been detected.

Based on the evaluation of Disclosure Controls, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Corporation's Disclosure Controls are effective in providing reasonable assurance that material information relating to the Corporation and its consolidated subsidiaries is made known to the Corporation's management.

BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from three Business Groups: Utilities, Power Generation and Global Enterprises. For the purposes of financial disclosure, corporate transactions are accounted for as Corporate and Other, and transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information. For additional information on the Corporation's Business Groups, refer to Note 22 to the consolidated financial statements.

TWO FOR ONE SHARE SPLIT

In July 2005, the Corporation's board of directors approved a two-for-one share split of the outstanding Class A and Class B shares. The share split took the form of a stock dividend whereby share owners received one additional Class A share for each Class A share held as of the record date and one additional Class B share for each Class B share held as of the record date. The stock dividend was paid on September 15, 2005 to share owners of record at the close of business on August 29, 2005. All share, stock option and per share amounts have been retroactively restated to reflect this share split.

TRANSFER OF THE 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 ("Transfer of the Retail Energy Supply Businesses"). Proceeds of the transfer were $90 million, of which $45 million was paid at closing, and the remainder was paid on May 4, 2005. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the Transfer of the Retail Energy Supply Businesses, resulted in a gain of $63.3 million before income taxes of $8.2 million and increased 2004 earnings by $55.1 million.

The Corporation's revenues and natural gas supply and purchased power costs after May 4, 2004 were reduced accordingly for 2004 and thereafter. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEML until the transfer of the relevant ATCO Gas natural gas purchase contracts to DEML was completed in September 2004. There is no ongoing impact on earnings resulting from the transfer of these businesses as natural gas and electricity have historically been sold to customers on a "no-margin" basis. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Under the various transaction agreements, 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 "transferred functions").

On May 4, 2004, DEML commenced supplying natural gas and electricity at regulated rates to residential, farm, commercial and small industrial customers in the ATCO Gas and ATCO Electric service areas and billing customers for their natural gas and electricity service.

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the Alberta Energy and Utilities Board ("AEUB") to do so), the agreements will terminate and 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. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below $200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and ATCO Electric.

The Corporation has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

DEML has entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek Business Services to provide billing and call centre services to ensure continued quality customer service. DEML has the ability to terminate this contract after the fifth anniversary upon immediate payment of termination fees which decline over the remaining term of the contract. Based upon current customer counts and service levels and a 10 year contract, revenues are estimated to be between $400-$500 million over the term of the contract.

ATCO Gas and ATCO Electric have also agreed not to compete in the regulated and unregulated retail energy business in Alberta for a period of ten years.

TXU EUROPE SETTLEMENT

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") for breach of its contract to purchase 27.5% of the power produced by the 1,000 megawatt Barking generating plant, in which the Corporation owns a 25.5% equity interest. In 2005, the Corporation received $83.1 million as its share of the partial settlement of the claim for damages related to TXU Europe's breach of this contract. An additional payment of $16.6 million was received on January 19, 2006 and a final installment of approximately $1.6 million is expected in the second quarter of 2006. The settlement is expected to generate earnings after income taxes of approximately $69 million, based on foreign currency exchange rates in effect on March 30, 2005, 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 the foreign currency exchange rates in effect at the time the earnings are recognized. For a description of the settlement, refer to Note 5 to the consolidated financial statements.

SELECTED ANNUAL AND QUARTERLY INFORMATION

	For the Three Months Ended				Year Ended
($ Millions except per share data)	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Dec. 31
	(unaudited)				
2005					
Revenues (1)	745.2	552.9	537.4	680.3	2,515.8
Earnings attributable to Class A and Class B shares (4) (5)	80.0	50.0	46.5	89.1	265.6
Earnings per Class A and Class B share (4) (5)	0.63	0.39	0.37	0.70	2.09
Diluted earnings per Class A and Class B share (4) (5)	0.63	0.39	0.37	0.69	2.08
2004					
Revenues (1)	1,169.2	674.7	530.5	637.0	3,011.4
Earnings attributable to Class A and Class B shares (2) (4) (5)	74.5	100.2	44.0	90.3	309.0
Earnings per Class A and Class B share (2) (4) (5)	0.59	0.79	0.35	0.71	2.44
Diluted earnings per Class A and Class B share (2) (4) (5)	0.59	0.78	0.35	0.71	2.43
2003					
Revenues	....	....	....	....	3,742.6
Earnings attributable to Class A and Class B shares (3) (4) (5)	....	....	....	....	259.1
Earnings per Class A and Class B share (3) (4) (5)	....	....	....	....	2.04
Diluted earnings per Class A and Class B share (3) (4) (5)	....	....	....	....	2.03

Notes:

(1) Prior to the Transfer of the Retail Energy Supply Businesses on May 4, 2004, the cost of natural gas and electricity purchased for ATCO Gas' and ATCO Electric's customers was included in revenues. As ATCO Gas and ATCO Electric no longer purchase natural gas and electricity for their customers, revenues since May 4, 2004, have decreased accordingly.

(2) Includes earnings of $55.1 million, earnings per share of $0.44 and diluted earnings per share of $0.43 on the Transfer of the Retail Energy Supply Businesses for the three months ended June 30, 2004, and for the year ended December 31, 2004.

(3) 2003 earnings attributable to Class A and Class B shares have been restated for retroactive changes in the methods of accounting for asset retirement obligations and stock based compensation.
(4) There were no discontinued operations or extraordinary items during these periods.
(5) Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.
(6) The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

	Year Ended December 31		
	2005	**2004**	**2003**
	($ Millions except per share data)		
Cash dividends declared per share (1):			
Series Second Preferred Shares:			
Series O	1.26	1.26	1.26
Series Q	1.48	1.48	1.48
Series R	1.33	1.33	1.33
Series S	1.65	1.65	1.65
Series T	1.26	1.26	1.26
Series U	1.26	1.26	1.26
Series V	1.31	1.31	1.31
Series W (1)	1.45	1.45	1.44
Series X (2)	1.50	1.50	0.93
Class A and Class B shares	1.10	1.06	1.02
Total assets	6,815.7	6,617.5	6,237.6
Long term debt	2,231.0	2,171.0	1,805.3
Non-recourse long term debt	673.8	760.9	806.1
Equity preferred shares	636.5	636.5	636.5
Class A and Class B share owners' equity	2,223.5	2,117.7	1,948.5

Notes:
(1) Issued December 3, 2002.
(2) Issued April 17, 2003.
(3) The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

RESULTS OF OPERATIONS

The principal factors that caused variations in **revenues** over the eight most recently completed quarters were:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses section), and lower prices of electricity and natural gas purchased for customers on a "no-margin" basis prior to May 4, 2004 (refer to the Utilities section);
- fluctuations in electricity and natural gas prices (refer to the Power Generation section);
- fluctuations in temperatures (refer to the Utilities section);
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section); and
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections).

The principal factors that caused variations in **earnings** over the eight most recently completed quarters were:

- gain on the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses and the Utilities sections);

- fluctuations in electricity prices and related spark spreads in Alberta and the United Kingdom ("U.K.") (refer to the Power Generation section);
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section);
- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections);
- the TXU Europe Settlement (refer to TXU Europe Settlement section); and
- changes in share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting Share prices (refer to Corporate and Other section).

Consolidated Operations

Revenues for the three months ended December 31, 2005, increased by $43.3 million to $680.3 million, primarily due to:

- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices;
- 2004 impact of 2004 General Rate Application adjustments for ATCO Gas related to the refund of deferred income taxes; and
- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities.

This increase was partially offset by:

- lower availability in the Barking generating plant due to a planned maintenance outage in September through November 2005;
- lower activity in ATCO Frontec projects; and
- lower natural gas fuel purchases recovered on a "no margin" basis at ATCO Power's Barking generating plant.

Revenues for the year ended December 31, 2005, decreased by $495.6 million to $2,515.8 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses in May 2004;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream; and
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue).

This decrease was partially offset by:

- higher prices for natural gas liquids in ATCO Midstream;
- increased business activity, including work for new customers, in ATCO I-Tek;
- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices;
- improved merchant performance in ATCO Power's U.K. operations; and
- a full year of operations at ATCO Power's 580 megawatt Brighton Beach generating plant commissioned in July 2004.

Earnings attributable to Class A and Class B shares for the three months ended December 31, 2005, decreased by $1.2 million ($0.01 per share) to $89.1 million ($0.70 per share), primarily due to:

- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream; and
- higher costs not recovered in ATCO Gas in 2005. In May 2005, ATCO Gas submitted a general rate application with the AEUB for the 2005, 2006 and 2007 test years. In August 2005, the AEUB approved interim refundable rates which recognized only 28% of the increased operating costs and rate base additions requested in the original application. On January 27, 2006, ATCO Gas received an AEUB decision which did not materially change the earnings based on the 2005 interim rates (the "ATCO Gas Decision"). The final impact of the decision will not be known until two subsequent regulatory processes are finalized (refer to Regulatory Matters – ATCO Gas section).

This decrease was partially offset by:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales in the Alberta market; and
- higher storage earnings due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream.

Earnings attributable to Class A and Class B shares for the year ended December 31, 2005, were $265.6 million ($2.09 per share). Earnings for 2004 were $253.9 million ($2.00 per share), **excluding** the $55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses in May 2004. Earnings for the year ended December 31, 2004, **including** the impact of the Transfer of the Retail Energy Supply Businesses, were $309.0 million ($2.44 per share).

Earnings attributable to Class A and Class B shares for the year ended December 31, 2005, **excluding** the impact of the Transfer of the Retail Energy Supply Businesses, increased by $11.7 million ($0.09 per share), primarily due to:

- higher storage earnings due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream; and
- the TXU Europe Settlement (refer to TXU Europe Settlement section).

This increase was partially offset by:

- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting Share prices since December 31, 2004;
- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream;
- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section); and
- warmer temperatures in ATCO Gas.

Return on common equity was 12.2% in 2005.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended December 31, 2005, increased by $27.7 million to $399.0 million, primarily due to:

- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities; and
- higher natural gas liquids shrinkage costs in ATCO Midstream due to higher natural gas prices.

This increase was partially offset by:

- 2004 one time impact of finalization of natural gas supply costs in ATCO Gas related to the Transfer of the Retail Energy Supply Businesses;
- lower business activity in ATCO Frontec; and
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue).

Operating expenses for the year ended December 31, 2005, decreased by $553.6 million to $1,553.9 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses in May 2004; and
- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream;
- higher fuel costs at ATCO Power's Barking generating plant due to natural gas fuel purchases recovered on a "no margin" basis; and
- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities.

Depreciation and amortization expenses for the three months ended December 31, 2005, increased by $3.3 million to $84.5 million, primarily due to:

- capital additions in 2005 and 2004.

Depreciation and amortization expenses for the year ended December 31, 2005, increased by $20.0 million to $311.5 million, primarily due to:

- capital additions in 2005 and 2004.

Interest expense for the three months ended December 31, 2005, decreased by $1.5 million to $51.4 million, primarily due to:

- lower interest rates on new financings issued to retire long term debt maturing in 2005; and
- retirement of non-recourse financings in 2005 and 2004.

This decrease was partially offset by:

- interest on new financings issued in 2005 and 2004 to fund capital expenditures in Utilities operations.

Interest expense for the year ended December 31, 2005, increased by $6.3 million to $210.0 million, primarily due to:

- interest on new financings issued in 2005 and 2004 to fund capital expenditures in Utilities operations; and
- interest on non-recourse financings for ATCO Power's Brighton Beach generating plant commissioned in July 2004.

This increase was partially offset by:

- lower interest rates on new financings issued to retire long term debt maturing in 2005; and
- retirement of non-recourse financings in 2005 and 2004.

Interest and other income for the three months ended December 31, 2005, increased by $0.2 million to $10.6 million, primarily due to:

- interest income on higher cash balances.

Interest and other income for the year ended December 31, 2005, increased by $5.8 million to $36.6 million, primarily due to:

- interest income on higher cash balances; and
- the recovery of ATCO Electric's carrying costs and interest associated with the AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in deferred income taxes (refer to Regulatory Matters – ATCO Electric section).

Income taxes for the three months ended December 31, 2005, increased by $15.2 million to $58.0 million, primarily due to:

- favorable tax adjustment in 2004 for ATCO Gas resulting from a change in income tax methodology as directed by the AEUB in its decision respecting ATCO Gas' 2003/2004 General Rate Application.

Income taxes for the year ended December 31, 2005, **including** the $8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses in May 2004, increased by $17.6 million to $175.6 million.

Income taxes for the year ended December 31, 2005, **excluding** the $8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses, increased by $25.8 million to $175.6 million, primarily due to:

- higher earnings; and
- favorable tax adjustment in 2004 for ATCO Gas resulting from a change in income tax methodology as directed by the AEUB in its decision respecting ATCO Gas' 2003/2004 General Rate Application.

Segmented Information

Segmented revenues for the three months and the year ended December 31, 2005, were as follows:

($ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2005	2004	**2005**	2004
	(unaudited)			
Utilities (1)	**305.5**	297.9	**1,195.9**	1,789.8
Power Generation	**208.2**	183.9	**761.7**	653.2
Global Enterprises (2)	**202.7**	188.2	**688.0**	920.1
Corporate and Other	**3.2**	3.9	**12.4**	11.6
Intersegment eliminations	**(39.3)**	(36.9)	**(142.2)**	(363.3)
Total	**680.3**	637.0	**2,515.8**	3,011.4

Notes:

(1) Prior to the Transfer of the Retail Energy Supply Businesses on May 4, 2004, the cost of natural gas and electricity purchased for ATCO Gas' and ATCO Electric's customers was included in revenues. As ATCO Gas and ATCO Electric no longer purchase natural gas and electricity for their customers, revenues since May 4, 2004, have decreased accordingly.

(2) Subsequent to the Transfer of the Retail Energy Supply Businesses on May 4, 2004, ATCO Midstream purchased lower volumes of natural gas for ATCO Gas.

Segmented earnings attributable to Class A and Class B shares for the three months and the year ended December 31, 2005, were as follows:

($ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2005	2004	**2005**	2004
	(unaudited)			
Utilities (1)	**32.5**	38.5	**106.0**	168.7
Power Generation	**36.1**	24.1	**103.0**	80.0
Global Enterprises	**28.2**	30.8	**81.0**	72.1
Corporate and Other	**(7.5)**	(3.6)	**(23.5)**	(14.8)
Intersegment eliminations	**(0.2)**	0.5	**(0.9)**	3.0
Total	**89.1**	90.3	**265.6**	309.0

Note:

(1) The December 31, 2004, earnings include $55.1 million (earnings per share of $0.44) and (diluted earnings per share of $0.43) resulting from the Transfer of the Retail Energy Supply Businesses.

Utilities

Revenues from the Utilities Business Group for the three months ended December 31, 2005, increased by $7.6 million to $305.5 million, primarily due to:

- 2004 impact of 2004 General Rate Application adjustments for ATCO Gas related to the refund of deferred income taxes;
- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities; and
- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section).

This increase was partially offset by:

- reduced recoveries of natural gas costs and lower storage revenues as ATCO Gas is no longer storing or selling natural gas from its Carbon natural gas storage facility. ATCO Gas has leased the entire storage capacity of the facility to ATCO Midstream for the period April 1, 2005 to March 31, 2006.

Temperatures in ATCO Gas for the three months ended December 31, 2005, were 14.1% warmer than normal, compared to 9.8% warmer than normal for the corresponding period in 2004.

Revenues from the Utilities Business Group for the year ended December 31, 2005, decreased by $593.9 million to $1,195.9 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses in May 2004;
- reduced recoveries of natural gas costs and lower storage revenues as ATCO Gas is no longer storing or selling natural gas from its Carbon natural gas storage facility. ATCO Gas has leased the entire storage capacity of the facility to ATCO Midstream for the period April 1, 2005 to March 31, 2006; and
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue).

This decrease was partially offset by:

- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities;
- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section);
- 2004 impact of 2004 General Rate Application adjustments for ATCO Gas related to the refund of deferred income taxes; and
- higher transmission charges recovered from customers in ATCO Gas.

Temperatures in ATCO Gas in 2005 were 7.8% warmer than normal, compared to 3.0% warmer than normal in 2004.

Earnings for the three months ended December 31, 2005, decreased by $6.0 million to $32.5 million, primarily due to:

- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section); and
- warmer temperatures in ATCO Gas.

Earnings for the year ended December 31, 2005, were $106.0 million. Earnings for 2004 were $113.6 million, **excluding** the $55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses in May 2004. Earnings for the year ended December 31, 2004, **including** the impact of the Transfer of the Retail Energy Supply Businesses, were $168.7 million.

Earnings for the year ended December 31, 2005, **excluding** the impact of the Transfer of the Retail Energy Supply Businesses, decreased by $7.6 million, primarily due to:

- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section); and
- warmer temperatures in ATCO Gas.

This decrease was partially offset by:

- impact of the AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in deferred income taxes recorded in ATCO Electric (refer to Regulatory Matters – ATCO Electric section).

Operating expenses for the year ended December 31, 2005, decreased by $611.7 million to $716.9 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses in May 2004.

The decrease was partially offset by:

- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities.

Power Generation

Revenues from the Power Generation Business Group for the three months ended December 31, 2005, increased by $24.3 million to $208.2 million, primarily due to:

- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices;
- higher revenues at ATCO Power's Osborne generating plant due to a planned maintenance outage in the fourth quarter of 2004; and
- improved merchant performance in ATCO Power's U.K. operations.

This increase was partially offset by:

- lower availability in ATCO Power's Barking generating plant due to a planned maintenance outage in September through November 2005; and
- lower natural gas fuel purchases recovered on a "no margin" basis at ATCO Power's Barking generating plant.

Revenues from the Power Generation Business Group for the year ended December 31, 2005, increased by $108.5 million to $761.7 million, primarily due to:

- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices;
- improved merchant performance in ATCO Power's U.K. operations; and
- a full year of operations at ATCO Power's 580 megawatt Brighton Beach generating plant commissioned in July 2004.

This increase was partially offset by:

- lower availability in ATCO Power's Barking generating plant due to a planned maintenance outage in September through November 2005.

Earnings for the three months ended December 31, 2005, increased by $12.0 million to $36.1 million, primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales in the Alberta market;
- a settlement with a supplier for damages due to equipment defects in ATCO Power's U.K. operations; and
- improved merchant performance in ATCO Power's U.K. operations.

This increase was partially offset by:

- lower availability in ATCO Power's Barking generating plant due to a planned maintenance outage in September through November 2005.

Alberta Power Pool electricity prices for the three months ended December 31, 2005, averaged $117.07 per megawatt hour, compared to average prices of $55.07 per megawatt hour for the corresponding period in 2004. Natural gas prices for the three months ended December 31, 2005, averaged $10.77 per gigajoule, compared to average prices of $6.16 per gigajoule for the corresponding period in 2004. The consequence of these changes in electricity and natural gas prices was an average spark spread of $36.31 per megawatt hour for the three months ended December 31, 2005, compared to $8.87 per megawatt hour for the corresponding period in 2004.

Spark spread is related to the difference between Alberta Power Pool electricity prices and the marginal cost of producing electricity from natural gas. These spark spreads are based on an approximate industry heat rate of 7.5 gigajoules per megawatt hour.

Changes in spark spread affect the results of approximately 300 megawatts of plant capacity owned in Alberta by ATCO Power out of a total world wide owned capacity of approximately 1,318 megawatts.

Earnings for the year ended December 31, 2005, increased by $23.0 million to $103.0 million, primarily due to:

- the TXU Europe Settlement (refer to TXU Europe Settlement section);
- improved merchant performance in ATCO Power's U.K. operations;
- a full year of operations at ATCO Power's 580 megawatt Brighton Beach generating plant commissioned in July 2004; and

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales in the Alberta market.

This increase was partially offset by:

- lower availability in ATCO Power's Barking generating plant due to a planned maintenance outage in September through November 2005.

Alberta Power Pool electricity prices in 2005, averaged $70.36 per megawatt hour, compared to average prices of $54.59 per megawatt hour in 2004. Natural gas prices in 2005, averaged $8.27 per gigajoule, compared to average prices of $6.19 per gigajoule in 2004. The consequence of these changes in electricity and natural gas prices was an average spark spread of $8.32 per megawatt hour in 2005, compared to $8.16 per megawatt hour in 2004.

Operating expenses for the year ended December 31, 2005, increased by $68.0 million to $414.7 million, primarily due to:

- higher fuel costs at ATCO Power's Barking generating plant due to natural gas fuel purchases recovered on a "no margin" basis; and
- higher fuel costs at ATCO Power's Alberta gas fired plants due to higher natural gas prices.

At December 31, 2005, all of ATCO Power's non-regulated independent generating plants were in service.

During the three months ended December 31, 2005, Alberta Power (2000)'s **deferred availability incentive** account increased by $14.4 million to $59.7 million. The increase was due to additional availability incentives received for improved plant availability. During the three months ended December 31, 2005, the amortization of deferred availability incentives, recorded in revenues, increased by $0.7 million to $2.7 million as compared to the same period in 2004.

During the year ended December 31, 2005, Alberta Power (2000)'s **deferred availability incentive** account increased by $13.6 million to $59.7 million. The increase was due to additional availability incentives received for plant availability in excess of planned outages and amortization. During the year ended December 31, 2005, the amortization of deferred availability incentives, recorded in revenues, increased by $1.3 million to $8.9 million as compared to 2004.

Global Enterprises

Revenues from the Global Enterprises Business Group for the three months ended December 31, 2005, increased by $14.5 million to $202.7 million, primarily due to:

- higher storage revenues due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream.

This increase was partially offset by:

- lower activity in ATCO Frontec projects; and
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream.

Revenues from the Global Enterprises Business Group for the year ended December 31, 2005, decreased by $232.1 million to $688.0 million, primarily due to:

- lower volumes of natural gas purchased in ATCO Midstream for ATCO Gas as a result of the Transfer of the Retail Energy Supply Businesses; and
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher prices for natural gas liquids in ATCO Midstream;
- higher storage revenues due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream; and
- increased business activity, including work for new customers, in ATCO I-Tek.

Earnings for the three months ended December 31, 2005, decreased by $2.6 million to $28.2 million, primarily due to:

- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher storage earnings due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream.

Earnings for the year ended December 31, 2005, increased by $8.9 million to $81.0 million, primarily due to:

- higher storage earnings due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream; and
- increased business activity, including work for new customers, in ATCO I-Tek.

This increase was partially offset by:

- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream.

Operating expenses for the year ended December 31, 2005, decreased by $250.3 million to $538.8 million, primarily due to:

- lower volumes of natural gas purchased in ATCO Midstream for ATCO Gas as a result of the Transfer of the Retail Energy Supply Businesses; and
- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream.

Corporate and Other

Earnings for the three months ended December 31, 2005 decreased by $3.9 million to $(7.5) million, primarily due to:

- increased administrative costs; and
- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting Share prices since September 30, 2005.

Earnings for the year ended December 31, 2005 decreased by $8.7 million to $(23.5) million, primarily due to:

- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting Share prices since December 31, 2004; and
- increased administrative costs.

REGULATORY MATTERS

Regulated operations are conducted by 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 the Corporation's wholly owned subsidiary, CU Inc.

In July 2004, the AEUB issued its generic cost of capital decision. The decision established a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity based upon a return of 9.60% on common equity. This rate of return is 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. This adjustment mechanism is the same as the National Energy Board uses in determining its formula based rate of return. The AEUB will undertake a review of this mechanism for the year 2009 or if the rate of return resulting from the formula is less than 7.6% or greater than 11.6%. The AEUB also noted that any party, at any time, could petition for a review of the adjustment formula if that party can demonstrate a material change in facts or circumstances.

The decision also established the appropriate capital structure for each utility regulated by the AEUB. The AEUB 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.

In November 2004, the AEUB announced a generic return on common equity of 9.50% for 2005 and in November 2005 announced a generic return on common equity of 8.93% for 2006. 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 companies' 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.

In July 2004, ATCO Gas and ATCO Electric filed applications with the AEUB addressing the impact on the 2003 and 2004 revenue requirements of the Transfer of the Retail Energy Supply Businesses to DEML and the customer care volume forecast for services provided by ATCO I-Tek Business Services for 2003 and 2004. In April and May 2005, the AEUB issued decisions which resulted in an increase to revenues and earnings of $2.4 million and $1.6 million, respectively.

In June 2005, as part of their rate applications, ATCO Electric and ATCO Gas submitted a filing to the AEUB that addressed certain common matters. ATCO Pipelines is also a party to this filing as the concerns are common to all three utilities. This filing included evidence regarding the appropriate ratemaking approach in the determination of utility revenue requirements as well as treatment of pension costs, executive compensation, head office rent expense and the continued use of preferred shares as a form of financing for the three utilities. The AEUB is expected to hear this filing in May 2006 and a decision is expected in the fourth quarter of 2006.

ATCO Electric

In May 2005, ATCO Electric filed a general tariff application with the AEUB for the 2005 and 2006 test years requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. A decision from the AEUB on the general tariff application is not expected until March 2006. In May and June 2005, ATCO Electric filed applications requesting interim refundable rates for distribution and transmission operations, pending the AEUB's decision on the general tariff application. On July 14, 2005, ATCO Electric received a decision from the AEUB approving its requested interim refundable rates for distribution operations. On September 7, 2005, ATCO Electric received a decision from the AEUB approving an interim refundable rate increase of $5.0 million for transmission operations. Revenues associated with these interim refundable rates were recorded in 2005.

In August 2002, the AEUB issued a decision in which it denied ATCO Electric's application to adjust its 2001 and 2002 transmission and distribution revenue requirements by $4.6 million for changes in the amounts of deferred income taxes recorded. In November 2002, ATCO Electric filed a review and variance application of the August 2002 decision with the AEUB. In May 2005, the AEUB changed its August 2002 decision and allowed ATCO Electric to increase its revenues and earnings by $4.6 million.

ATCO Gas

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. In May 2005, ATCO Gas submitted a general rate application with the AEUB for the 2005, 2006 and 2007 test years. In August 2005, the AEUB approved interim refundable rates which recognized only 28% of the increased operating costs and rate base additions requested in the original application. On January 27, 2006, ATCO Gas received an AEUB decision which did not materially change the earnings based on the 2005 interim rates. The final impact of the decision will not be known until two subsequent regulatory processes are finalized. There will be no immediate impact on the ATCO Gas distribution rates as interim rates will continue until final rates are decided by the AEUB in late 2006 or early 2007. The general rate application decision approved a return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity is 9.5% in 2005, 8.93% in 2006, and is yet to be determined for 2007.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties in the City of Calgary, known as the Calgary Stores Block, for $6.6 million (excluding costs of disposition) and allocated $4.1 million of the proceeds to customers and $1.8 million to ATCO Gas. In January 2004, the Alberta Court of Appeal overturned this decision and directed the AEUB to allocate $5.4 million of the proceeds to ATCO Gas. The City of Calgary has appealed this decision to the Supreme Court of Canada, which has also granted ATCO Gas leave to cross-appeal the decision. The Supreme Court of Canada heard the appeal on May 11, 2005 and on February 9, 2006 rendered its decision. The Supreme Court dismissed the City of Calgary's appeal and allowed ATCO Gas' cross-appeal. The decision will not impact the 2005 earnings of ATCO Gas, as the Supreme Court has directed the AEUB to issue a new decision in accordance with the Supreme Court's ruling. Net proceeds totaling $4.1 million from the sale are being held pending AEUB approval. It is anticipated that the AEUB will issue a new decision before the end of the first quarter of 2006.

In March 2004, the AEUB directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon natural gas storage facility for the 2004/2005 storage year, which ended on March 31, 2005, and allowed ATCO Midstream to continue to utilize the remaining uncontracted capacity at a rate of $0.45 per gigajoule, up from $0.41 per gigajoule. ATCO Gas was granted leave to appeal this AEUB decision to the Alberta Court of Appeal. On June 17, 2005 the appeal was dismissed. On September 16, 2005, ATCO Gas filed for leave to appeal the Alberta Court of Appeal's decision to the Supreme Court of Canada. The leave to appeal was denied on January 19, 2006.

In July 2004, the AEUB initiated a written process to consider its role in regulating the operations of the Carbon natural gas storage facility. On June 15, 2005, the AEUB issued a decision with respect to this process. In addition to addressing other matters, the decision found that the AEUB has the authority, when necessary in the public interest, to direct a utility to utilize a particular asset in a specific manner, even over the objection of the utility. ATCO Gas has filed for leave to appeal the decision with the Alberta Court of Appeal. On October 3, 2005, the AEUB established processes to review the use of the Carbon natural gas storage facility for utility purposes.

ATCO Gas' position is that the Carbon natural gas storage facility is no longer required for utility service. Accordingly, in March 2005, ATCO Gas filed a letter with the AEUB in which it withdrew all evidence previously filed by it with respect to the 2005/2006 Carbon Storage Plan, thus providing notice that none of the related costs and revenues will form part of regulated operations on or after April 1, 2005. On March 23, 2005, the AEUB issued an interim order directing ATCO Gas to maintain the Carbon natural gas storage facility in rate base and confirming a lease of the entire storage capacity to ATCO Midstream at a placeholder rate of $0.45 per gigajoule until otherwise determined by the AEUB. ATCO Gas filed for leave to appeal the interim order on April 15, 2005.

ATCO Gas has filed an application with the AEUB to address, among other things, corrections required to historical transportation imbalances that have impacted ATCO Gas' deferred gas account. In April 2005, the AEUB issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in a decrease to revenues and earnings of $1.8 million and $1.2 million, respectively. The City of Calgary has filed for leave to appeal the AEUB's decision. ATCO Gas has filed a cross appeal of the AEUB's decision. The cross appeal is contingent upon the granting of the City of Calgary's leave to appeal which is scheduled to be heard in February 2006.

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 renders a judgment in the appeal regarding the Calgary Stores Block disposition and allocation of proceeds discussed above. The Supreme Court of Canada rendered its decision on the Calgary Stores Block matter on February 9, 2006. ATCO Gas is now required to submit a filing to the AEUB to approve the allocation of the net proceeds. The net proceeds of the sale remain in trust pending AEUB approval.

ATCO Pipelines

The AEUB has announced that it will hold a hearing to address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. This hearing is expected to take place in 2006.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term and non-recourse debt and preferred shares. Commercial paper borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

Cash flow from operations for the three months ended December 31, 2005, increased by $23.4 million to $187.8 million, primarily due to:

- increased cash flow after removal of non-cash adjustments.

Cash flow from operations for the year ended December 31, 2005, increased by $121.0 million to $659.3 million, primarily due to:

- the TXU Europe Settlement (refer to TXU Europe Settlement section);
- higher earnings; and
- increased deferred availability incentives in Alberta Power (2000), primarily due to availability incentive payments received for improved plant availability.

Investing for the three months ended December 31, 2005, increased by $35.1 million to $160.3 million, primarily due to:

- increased capital expenditures; and
- changes in non-current deferred electricity costs.

This increase was partially offset by:

- changes in non-cash working capital in respect of investing activities.

Capital expenditures for the three months ended December 31, 2005, increased by $32.1 million to $181.2 million, primarily due to:

- increased investment in regulated natural gas transportation and distribution projects.

This increase was partially offset by:

- lower investment in non-regulated power generation projects

Investing for the year ended December 31, 2005, increased by $1.1 million to $470.4 million, primarily due to:

- changes in non-current deferred electricity costs;
- changes in non-cash working capital in respect of investing activities; and
- lower contributions by utility customers for extensions to plant.

This increase was partially offset by:

- proceeds from the Transfer of the Retail Energy Supply Businesses; and
- lower capital expenditures.

Capital expenditures for the year ended December 31, 2005, decreased by $8.8 million to $526.7 million, primarily due to:

- lower investment in power generation and regulated electric projects.

This decrease was partially offset by:

- increased investment in regulated natural gas transportation and distribution projects.

During the three months ended December 31, 2005, the Corporation **issued**:

- $185.0 million of 5.183% Debentures due November 21, 2035.

During the three months ended December 31, 2005, the Corporation **redeemed**:

- $35.4 million of long term debt; and
- $9.1 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $140.5 million.

During the year ended December 31, 2005, the Corporation **issued**:

- $185.0 million of 5.183% Debentures due November 21, 2035; and
- $37.0 million of other long term debt.

During the year ended December 31, 2005, the Corporation **redeemed**:

- $125.0 million of 8.43% Debentures 1995 Series;
- $42.1 million of other long term debt; and
- $54.3 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of $0.6 million.

Foreign currency translation for the three months ended December 31, 2005, increased the Corporation's cash position by $0.3 million to $0.2 million.

Foreign currency translation for the year ended December 31, 2005, decreased the Corporation's cash position by $10.7 million to ($11.2) million, primarily as a result of:

- strengthening of the Canadian dollar which resulted in a reduction in the value of cash balances denominated in U.K. pounds when translated into Canadian dollars.

Capital expenditures to maintain capacity, meet planned growth and fund future development activities are expected to be approximately $575 million in 2006. These expenditures are uncommitted and relate primarily to utility operations.

Contractual obligations for the next five years and thereafter are as follows:

	Payments Due by Period				
Contractual Obligations	**Total**	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**After 5 Years**
($ Millions)					
Long term debt	2,231.0	175.0	166.0	250.0	1,640.0
Non-recourse long term debt	730.8	57.0	127.9	147.2	398.7
Operating leases	63.2	15.9	27.6	12.7	7.0
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1)	9.0	1.1	2.2	2.2	3.5
Alberta Power (2000) coal purchase contracts (2)	656.8	47.3	98.9	105.0	405.6
Alberta Power (2000) capital expenditures (3)	8.8	8.8	-	-	-
ATCO Power natural gas fuel supply contracts (4)	289.2	46.3	101.8	100.0	41.1
ATCO Power operating and maintenance agreements (5)	166.6	14.8	35.0	33.5	83.3
ATCO Power capital expenditures (6)	1.8	1.8	-	-	-
ATCO Electric capital expenditures (7)	19.6	19.1	0.5	-	-
Other	13.7	13.7	-	-	-
Total	4,190.5	400.8	559.9	650.6	2,579.2

Notes:

(1) *ATCO Gas has ongoing obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. These obligations relate primarily to operational contracts pertaining to the Carbon natural gas storage facility, which was not included in the Transfer of the Retail Energy Supply Businesses to DEML and continues to be subject to AEUB regulation. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on December 31, 2005, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. DEML has agreed to purchase the natural gas purchased under these contracts at the prices paid by ATCO Gas.*

(2) Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the power purchase arrangements.
(3) Alberta Power (2000) has entered into contracts with suppliers to improve operating efficiency at certain of its generating plants.
(4) ATCO Power has various contracts to purchase natural gas for its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 78% of these costs. The balance of 22%, related to ATCO Power's Barking generating plant, is currently being recovered through merchant sales in the U.K. electricity market.
(5) ATCO Power has various contracts with suppliers to provide operating and maintenance services at certain of its generating plants.
(6) ATCO Power has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.
(7) ATCO Electric has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.

At December 31, 2005, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

($ Millions)	**Total**	**Used**	**Available**
Long term committed	326.0	11.9	314.1
Short term committed	600.0	-	600.0
Uncommitted	69.1	8.3	60.8
Total	995.1	20.2	974.9

The amount and timing of future financings will depend on market conditions and the specific needs of the Corporation.

Current and long term future income tax liabilities of $204.4 million at December 31, 2005, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

On May 20, 2004, the Corporation commenced a **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A shares. The bid expired on May 19, 2005. Over the life of the bid, 289,800 shares were purchased, of which 256,800 were purchased in 2004 and 33,000 were purchased in 2005. On May 20, 2005, the Corporation commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The bid will expire on May 19, 2006. From May 20, 2005, to February 22, 2006, 195,600 shares have been purchased, all of which were purchased in 2005.

It is the policy of the Corporation to **pay dividends** quarterly on its Class A and Class B shares. In 2005, the Corporation increased the dividends on Class A and Class B shares by $0.04 per share, the same increase as in 2004. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. For the first quarter of 2006, the **quarterly dividend** payment has been increased by $0.01 to $0.285 per share. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

On January 16, 2004, CU Inc. filed a base shelf prospectus which permits CU Inc. to issue up to an aggregate of $750.0 million of debentures over the twenty-five month life of the prospectus.

- On January 23, 2004, CU Inc. issued $180.0 million of 5.432% Debentures due January 23, 2019, at a price of 100 to yield 5.432%. The proceeds of the issue were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

- On November 18, 2004, CU Inc. issued $100.0 million of 5.096% Debentures due November 18, 2014, at a price of 100 to yield 5.096% and $200.0 million of 5.896% Debentures due November 20, 2034, at a price of 100 to yield 5.896%. The proceeds of the issues were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.
- On November 21, 2005, CU Inc. issued $185.0 million of 5.183% Debentures due November 21, 2035, at a price of 100 to yield 5.183%. The proceeds of the issue were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

OUTSTANDING SHARE DATA

At February 21, 2006, the Corporation had outstanding 82,939,286 Class A shares and 44,016,284 Class B shares.

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

If a take-over bid is made for the Class B shares which would result in the offeror owning more than 50% of the outstanding Class B shares and which would constitute a change in control of the Corporation, owners of Class A shares are entitled, for the duration of the bid, to exchange their Class A shares for Class B shares and to tender such Class B 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 shares are entitled to exchange their shares for Class B shares of the Corporation if ATCO Ltd., the present controlling share owner of the Corporation, ceases to own or control, directly or indirectly, more than 20,000,000 of the issued and outstanding Class B shares of the Corporation. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 6,400,000 Class A shares reserved for issuance in respect of options under the Corporation's stock option plan, 2,747,200 Class A shares are available for issuance at December 31, 2005. Options may be granted to directors, officers and key employees of the Corporation 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. As of February 21, 2006, options to purchase 1,471,400 Class A shares were outstanding.

TRANSACTIONS WITH RELATED PARTIES

The Corporation's transactions with related parties are in the normal course of business and under normal commercial terms. For a description of these transactions, refer to Note 18 to the consolidated financial statements.

BUSINESS RISKS

On February 16, 2005, the Kyoto Protocol came into effect. The Corporation is unable to determine what impact the protocol may have on its operations as the Government of Canada has not yet provided industry specific details for its 2005 Climate Change Plan. It is anticipated that the Corporation's power purchase arrangements ("PPA's") relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the protocol.

Regulated Operations

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AEUB, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates, subject to final determination. These subsidiaries are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AEUB of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. The Corporation's ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process.

Weather

Weather fluctuations have a significant impact on throughput in ATCO Gas. Since approximately 50% of ATCO Gas' delivery charge is recovered based on throughput, ATCO Gas' revenues and earnings are sensitive to weather. Weather that is 10% warmer or colder than normal temperatures impacts annual earnings by approximately $11.4 million.

Transfer of the Retail Energy Supply Businesses

Although ATCO Gas and ATCO Electric have 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 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.

The Corporation has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations in respect of the ongoing relationships to DEML contemplated under the transaction agreements.

As a result of the agreements with DEML, ATCO Gas and ATCO Electric are no longer involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to own the assets and provide the transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and a fair return.

Late Payment Penalties on Utility Bills

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.

Alberta Power (2000)

Included in regulated operations are the generating plants of Alberta Power (2000), which 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 expiry of the PPA's. 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.

Substantially all the electricity generated by Alberta Power (2000) is sold pursuant to PPA's. Under the PPA's, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPA's were based.

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.

At December 31, 2005, the Corporation had recorded $59.7 million of deferred availability incentives.

Fuel costs in Alberta Power (2000) are mostly for coal supply. To protect against volatility in coal prices, Alberta Power (2000) owns or has sufficient coal supplies under long term contracts for the anticipated lives of its Battle River and Sheerness coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

As a result of unprecedented drought conditions, the water levels in the cooling pond used by the Battle River generating plant in its production of electricity had fallen to all-time lows in early 2003 and in 2004 and the Corporation was forced to curtail production of electricity. Water levels in the cooling pond have returned to normal for this time of year and there has been no curtailment of production in 2005 or to date in 2006.

Alberta Environment plans to implement mercury emission standards for coal-fired generating plants through a new provincial regulation that is expected to be in place by March 2006. Owners of coal-fired generating plants are required to submit proposals on capturing at least 70% of the mercury in the coal burned in their plants by March 2007. The proposals for mercury emission reduction must be implemented by 2010. It is anticipated that the Corporation's PPA's relating to its coal-fired generating plants will allow the Corporation to recover most of the costs associated with complying with the new regulation.

Measurement Inaccuracies in Metering Facilities

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

Non-Regulated Operations

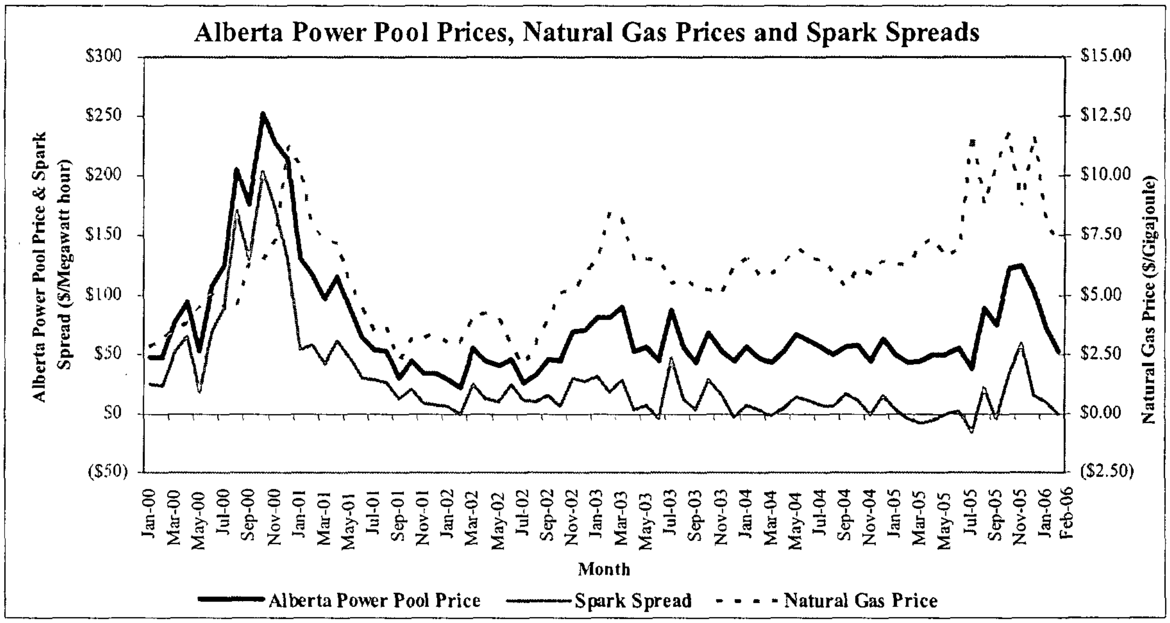
The Corporation's non-regulated operations are complementary to its traditional regulated businesses and are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its regulated operations. The Corporation's non-regulated operations are subject to the risks faced by any commercial enterprise in those industries and in those countries in which they operate.

ATCO Power

The Corporation's portfolio of non-regulated electric generating plants is made up of gas-fired cogeneration, gas-fired combined cycle, gas-fired simple cycle, and small hydro plants. The majority of operating income from power generation operations is derived through long term power, steam and transmission support agreements. Where long term agreements are in place, the purchaser assumes the fuel supply and price risks and the Corporation, under these agreements, assumes the operating risks.

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2005, sales from approximately 71% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 29% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. In 2006, these percentages are expected to be approximately the same. These sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a strong correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation. The correlation is expected to increase in the future as customer load grows and older plants are decommissioned.

Alberta Power Pool electricity prices, natural gas prices and related spark spreads can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period January 2000 to February 2006.



Changes in Alberta Power Pool electricity prices, natural gas prices and related spark spreads may have a significant impact on the Corporation's earnings and cash flow from operations in the future. It is the Corporation's policy to continually monitor the status of its non-regulated electrical generating capacity that is not subject to long term commitments.

Since October 2004, the output from ATCO Power's Barking generating plant previously sold to TXU Europe (refer to TXU Europe Settlement section) has been sold into the U.K. power exchange market. In the U.K., electricity generators, on average, sell over 90% of their output to electricity suppliers in bilateral contracts; use power exchanges for approximately 7% of their output, and sell the remaining 2-3% via the Balancing Mechanism. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants, and the market has experienced an increase in electricity prices due to the increased world prices for natural gas. The Barking generating plant has a long term, fixed price gas purchase agreement and, as a result, has been able to experience increased margins due to rising market prices for electricity. Changes in the U.K. market electricity prices may have an impact on the Corporation's earnings and cash flow from operations in the future.

ATCO Power has financed its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. 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. The guarantees outstanding at December 31, 2005, are described in Note 11 to the consolidated financial statements. To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

ATCO Midstream

Timing, capacity and demand of ATCO Midstream's storage business as well as changes in market conditions may impact the Corporation's earnings and cash flow from storage operations.

ATCO Midstream extracts ethane and other natural gas liquids from natural gas streams at its extraction plants. These products are sold under either long term cost of service arrangements or market based arrangements. Changes in market conditions may impact the Corporation's earnings and cash flow from natural gas liquids extraction operations.

ATCO Frontec

ATCO Frontec's operations include providing support to military agencies in foreign locations which may be subject to political risk.

CONTINGENCIES

The Government of Canada has 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 without merit 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.

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. For details on the financial instruments in place at December 31, 2005, refer to Note 20 to the consolidated financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

Unrecorded future income tax liabilities of the regulated operations amounted to $171.3 million at December 31, 2005. This balance includes $28.2 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. The remainder, amounting to $143.1 million, is expected to be recovered from utility customers through inclusion in future rates. There are tax loss carryforwards of $0.7 million for which no tax benefit has been recorded. These losses begin to expire in 2010. For additional information on the Corporation's unrecorded future income tax liabilities, refer to Note 7 to the consolidated financial statements.

Other than the financial instruments discussed under "Hedging", the Corporation does not have any off-balance sheet arrangements that have, or are likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Corporation's consolidated financial statements in accordance with generally accepted accounting principles 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. The Corporation's critical accounting estimates are discussed below.

Deferred Availability Incentives

As noted in the Business Risks section, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. As at December 31, 2005, the Corporation had recorded $59.7 million of deferred availability incentives. The amortization of deferred availability incentives, which was recorded in revenues, amounted to $8.9 million in 2005.

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 high case, low case and most likely scenarios for 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.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately $4.3 million, whereas the low case scenario would have resulted in lower revenues of approximately $2.2 million.

Employee Future Benefits

The expected long term rate of return on pension 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. Actual balanced fund performance over a longer period suggests that this premium is about 1%, which, when added to the long bond yield rate of 5.9% at the beginning of 2005, resulted in an expected long term rate of return of 6.9% for 2005. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, and asset diversification effect on portfolio returns.

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. The expected long term rate of return has declined over the past four years, from 8.1% in 2001 to 6.9% in the year ended December 31, 2005. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the same period has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

The liability discount rate that is used to calculate the cost of benefit obligations reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate has also declined over the same four year period, from 6.9% at the end of 2001 to 5.1% at the end of 2005. The result has been an increase in benefit obligations (i.e., an experience loss), which is contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10 percent of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation began amortizing a portion of the net cumulative experience losses on plan assets and accrued benefit obligations in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization during the three months and the year ended December 31, 2005.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the three months and the year ended December 31, 2005, are as follows: for drug costs, 9.3% starting in 2005 grading down over 8 years to 4.5%, and for other medical and dental costs, 4.0% for 2005 and thereafter. Combined with higher claims experience, the effect of these changes has been to increase the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AEUB decision to record the costs of employee future benefits when paid rather than accrued. Therefore, a significant portion of the benefit plans expense or income is unrecognized by the regulated operations, excluding Alberta Power (2000).

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2005 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.

	2005 Pension Benefit Plans		**2005 Other Post Employment Benefit Plans**	
	Accrued Benefit Obligation	**Benefit Plan Cost (Income)**	**Accrued Benefit Obligation**	**Benefit Plan Cost (Income)**
	($ Millions)			
Expected long term rate of return on plan assets				
1% increase (1)	-	(3.2)	-	-
1% decrease (1)	-	3.2	-	-
Liability discount rate				
1% increase (1)	(57.7)	(4.9)	(3.3)	(0.3)
1% decrease (1)	74.0	6.3	4.1	0.4
Future compensation rate				
1% increase (1)	18.1	2.5	-	-
1% decrease (1)	(15.6)	(2.1)	-	-
Long term inflation rate				
1% increase (1)(2)(3)	25.0	3.2	3.7	0.6
1% decrease (1) (3)	(42.7)	(5.2)	(3.0)	(0.5)

Notes:

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost (income), 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.

CHANGES IN ACCOUNTING POLICIES

During 2005, the Corporation adopted the recommendations of the Canadian Institute of Chartered Accountants ("CICA") pertaining to the consolidation of variable interest entities and lease arrangements. None of these policies had any material effect on the Corporation's financial statements. These changes in accounting policy are discussed in Note 1 to the consolidated financial statements.

Effective December 31, 2005, the Corporation retroactively adopted the CICA guideline pertaining to the disclosure and presentation of information by entities subject to rate regulation. This guideline no longer permits the netting of accrued and regulatory pension and other post employment benefits assets and liabilities, with the result that the Corporation's total assets and liabilities reported in 2004 increased by $154.4 million. This change in presentation had no effect on the Corporation's earnings and earnings per share or cash flows. Accounting for rate regulated operations is described in Note 2 to the consolidated financial statements.

February 22, 2006