



# **CONSOLIDATED FINANCIAL STATEMENTS**

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

February 21, 2007

**Auditors' Report**

**To the Share Owner of  
CU Inc.**

We have audited the consolidated balance sheets of **CU Inc.** as at December 31, 2006 and 2005 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

*PricewaterhouseCoopers LLP*

**Chartered Accountants**

Calgary, Alberta

**CU INC.**  
**CONSOLIDATED STATEMENT OF EARNINGS AND RETAINED EARNINGS**  
*(Millions of Canadian Dollars)*

	Note	Three Months Ended December 31		Year Ended December 31	
		<b>2006</b>	2005	<b>2006</b>	2005
<i>(Unaudited)</i>					
<b>Revenues</b>		<b>\$ 391.7</b>	\$ 382.2	<b>\$1,401.8</b>	\$1,490.0
<b>Costs and expenses</b>					
Natural gas supply		<b>0.7</b>	1.0	<b>2.5</b>	126.4
Purchased power		<b>12.5</b>	12.2	<b>46.1</b>	45.4
Operation and maintenance		<b>98.0</b>	92.1	<b>348.5</b>	333.3
Selling and administrative		<b>60.2</b>	49.8	<b>199.4</b>	189.3
Depreciation and amortization		<b>73.1</b>	65.5	<b>268.0</b>	235.4
Interest	6, 10	<b>41.5</b>	37.8	<b>165.9</b>	150.7
Franchise fees		<b>42.4</b>	49.5	<b>150.4</b>	152.3
		<b>328.4</b>	307.9	<b>1,180.8</b>	1,232.8
<b>Interest and other income</b>	5	<b>63.3</b>	74.3	<b>221.0</b>	257.2
<b>Earnings before income taxes</b>		<b>9.1</b>	4.8	<b>21.9</b>	12.7
<b>Income taxes</b>	6	<b>72.4</b>	79.1	<b>242.9</b>	269.9
		<b>21.1</b>	30.0	<b>81.8</b>	99.8
		<b>51.3</b>	49.1	<b>161.1</b>	170.1
<b>Dividends on equity preferred shares to parent corporation</b>		<b>3.5</b>	3.5	<b>14.0</b>	14.0
<b>Earnings attributable to Class A and Class B shares</b>		<b>47.8</b>	45.6	<b>147.1</b>	156.1
<b>Retained earnings at beginning of period</b>		<b>1,077.6</b>	1,044.2	<b>1,051.4</b>	1,036.3
		<b>1,125.4</b>	1,089.8	<b>1,198.5</b>	1,192.4
Dividends on Class A and Class B shares		<b>40.0</b>	38.4	<b>113.1</b>	141.0
<b>Retained earnings at end of period</b>		<b>\$1,085.4</b>	\$1,051.4	<b>\$1,085.4</b>	\$1,051.4

**CU INC.**  
**CONSOLIDATED BALANCE SHEET**  
*(Millions of Canadian Dollars)*

		December 31	
	Note	2006	2005
<b>ASSETS</b>			
<b>Current assets</b>			
Cash and short term investments		\$ -	\$ 35.3
Accounts receivable		224.4	197.0
Accounts receivable from parent and affiliate corporations		8.5	3.2
Inventories		70.3	65.9
Income taxes recoverable		2.0	-
Regulatory assets	2	13.3	19.1
Prepaid expenses		10.2	7.2
		<b>328.7</b>	<b>327.7</b>
<b>Property, plant and equipment</b>	7	<b>4,106.5</b>	<b>3,878.0</b>
<b>Regulatory assets</b>	2	<b>60.2</b>	<b>49.0</b>
<b>Other assets</b>	8	<b>28.3</b>	<b>38.2</b>
		<b>\$4,523.7</b>	<b>\$4,292.9</b>
<b>LIABILITIES AND SHARE OWNER'S EQUITY</b>			
<b>Current liabilities</b>			
Bank indebtedness	9	\$ 3.3	\$ -
Short term advances from parent and affiliate corporations	9	94.2	0.2
Accounts payable and accrued liabilities		169.7	175.8
Accounts payable to parent and affiliate corporations		28.1	26.4
Income taxes payable		-	12.4
Future income taxes	6	0.7	4.5
Regulatory liabilities	2	0.5	6.4
		<b>296.5</b>	<b>225.7</b>
<b>Future income taxes</b>	6	<b>54.6</b>	<b>64.5</b>
<b>Regulatory liabilities</b>	2	<b>30.1</b>	<b>22.5</b>
<b>Deferred credits</b>	11	<b>125.5</b>	<b>142.2</b>
<b>Long term debt</b>	10	<b>2,267.5</b>	<b>2,122.5</b>
<b>Equity preferred shares to parent corporation</b>	12	<b>256.5</b>	<b>256.5</b>
<b>Class A and Class B share owner's equity</b>			
Class A and Class B shares	13	407.6	407.6
Retained earnings		1,085.4	1,051.4
		<b>1,493.0</b>	<b>1,459.0</b>
		<b>\$4,523.7</b>	<b>\$4,292.9</b>

*[Original signed by K.M. Watson]*

*[Original signed by B.K. French]*

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DIRECTOR

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DIRECTOR

**CU INC.**  
**CONSOLIDATED STATEMENT OF CASH FLOWS**  
*(Millions of Canadian Dollars)*

	Note	Three Months Ended December 31		Year Ended December 31	
		2006	2005	2006	2005
<i>(Unaudited)</i>					
<b>Operating activities</b>					
Earnings attributable to Class A and Class B shares		\$ 47.8	\$ 45.6	\$ 147.1	\$ 156.1
Adjustments for:					
Depreciation and amortization		73.1	65.5	268.0	235.4
Future income taxes		8.7	(3.6)	(0.9)	4.5
Deferred availability incentives		(41.0)	14.5	(20.2)	13.7
Other		5.6	3.4	0.8	8.7
Funds generated by operations		94.2	125.4	394.8	418.4
Changes in non-cash working capital	15	(34.1)	26.3	(61.2)	88.8
<b>Cash flow from operations</b>		<b>60.1</b>	<b>151.7</b>	<b>333.6</b>	<b>507.2</b>
<b>Investing activities</b>					
Purchase of property, plant and equipment		(172.7)	(173.5)	(536.1)	(498.4)
Proceeds on transfer of retail energy supply businesses					
- net of income taxes	3	-	-	-	43.4
Costs on disposal of property, plant and equipment		(4.7)	(4.7)	(12.0)	(6.9)
Contributions by utility customers for extensions					
to plant		20.1	6.7	81.3	44.1
Non-current deferred electricity costs		(8.7)	(5.7)	4.5	(15.7)
Changes in non-cash working capital	15	14.8	23.4	(13.1)	(2.3)
Income tax reassessment	6	-	-	(12.8)	-
Other		(2.8)	(1.4)	(6.9)	(6.5)
		(154.0)	(155.2)	(495.1)	(442.3)
<b>Financing activities</b>					
Issue of long term debt		320.0	185.0	320.0	185.0
Repayment of long term debt		(175.0)	-	(175.0)	(125.0)
Dividends paid to Class A and Class B share owner		(40.0)	(38.4)	(113.1)	(141.0)
Changes in non-cash working capital	15	(0.1)	-	(0.1)	(0.4)
Other		(2.2)	(2.2)	(2.9)	(2.8)
		102.7	144.4	28.9	(84.2)
<b>Cash position <sup>(1)</sup></b>					
Increase (decrease)		8.8	140.9	(132.6)	(19.3)
Beginning of period		(106.3)	(105.8)	35.1	54.4
<b>End of period</b>		<b>\$ (97.5)</b>	<b>\$ 35.1</b>	<b>\$ (97.5)</b>	<b>\$ 35.1</b>

<sup>(1)</sup> Cash position includes cash and short term investments less current bank indebtedness and short term advances from parent and affiliate corporations.

**CU INC.**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**  
**DECEMBER 31, 2006**

*(tabular amounts in millions of Canadian dollars)*

**1. Summary of significant accounting policies**

***Financial Statement Presentation***

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and include the accounts of CU Inc. and its subsidiaries (the “Corporation”). Principal operations are Utilities (ATCO Electric, ATCO Gas, ATCO Pipelines) and Power Generation (Alberta Power (2000)).

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) are collectively referred to in these consolidated financial statements as the “regulated operations”. Accounting for rate regulated operations is described in Note 2.

***Use of Estimates***

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

***Revenue Recognition***

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

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

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

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

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.

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

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.

### ***Natural Gas Supply***

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

### ***Purchased Power***

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

### ***Income Taxes***

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

### ***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 Alberta Energy and Utilities Board (“AEUB”) for debt and equity capital.

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

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

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

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

### ***Deferred Financing Charges***

Issue costs of long term debt are amortized over the life of the debt and issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue. 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 and other generating plants of Alberta Power (2000).

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

### ***Long Term Debt Due Within One Year***

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements of either the Corporation or its parent corporation, Canadian Utilities Limited, 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.

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

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

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

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

### ***Employee Future Benefits***

The Corporation participates, together with Canadian Utilities Limited and its subsidiary corporations, in a group defined benefit pension plan ("the Group Plan"). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Corporation is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid.

The Corporation participates, together with Canadian Utilities Limited and its subsidiary corporations, in other post employment benefit and certain other group defined benefit pension plans. These plans are administered on a combined basis, and the Corporation accrues for its obligations under these plans. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for each plan as a whole; for certain other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of wage and salary increases, age at retirement and expected health care costs. Experience gains and losses and the effect of changes in assumptions in excess of 10% of the accrued benefit obligations, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

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

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

### ***Stock Based Compensation Plans***

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.

## **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.

## 2. Accounting for rate regulated operations (continued)

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

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

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

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

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

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

### *Financial statement effects of rate regulation*

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

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

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.

## 2. Accounting for rate regulated operations (continued)

The regulatory assets and liabilities comprise the following:

	2006	2005
<i>Regulatory assets – current:</i>		
Deferred hearing costs	\$ -	\$ 8.8
Deferred electricity costs	1.7	-
Other regulatory assets	11.6	10.3
	<b>\$13.3</b>	<b>\$19.1</b>
<i>Regulatory assets – non-current:</i>		
Regulatory pension asset (Note 17)	\$17.0	\$14.0
Regulatory other post employment benefits asset (Note 17)	27.6	22.0
Deferred electricity costs	7.1	5.4
Deferred hearing costs	1.4	1.6
Reserves for injuries and damages	2.0	5.4
Other regulatory assets	5.1	0.6
	<b>\$60.2</b>	<b>\$49.0</b>
<i>Regulatory liabilities – current:</i>		
Deferred electricity cost recoveries	\$ -	\$ 4.0
Reserves for injuries and damages	-	0.8
Other regulatory liabilities	0.5	1.6
	<b>\$ 0.5</b>	<b>\$ 6.4</b>
<i>Regulatory liabilities – non-current:</i>		
Deferred royalty credits	\$19.7	\$18.1
Deferred electricity cost recoveries	6.2	-
Deferred hearing costs	0.4	2.6
Reserves for injuries and damages	2.8	0.8
Other regulatory liabilities	1.0	1.0
	<b>\$30.1</b>	<b>\$22.5</b>

### *Employee future benefits*

The Corporation participates, together with its ultimate parent corporation, Canadian Utilities Limited, and affiliated corporations, in a group defined benefit pension plan (“the Group Plan”). The assets of the Group Plan are not segregated for each participating entity and are used to provide pensions to all members of this plan. In this circumstance, the Corporation is required to account for the Group Plan as a defined contribution plan whereby contributions are expensed as paid. The Corporation accrues for its obligations under other post employment benefit and certain other defined pension plans.

Upon the adoption of the current accounting standard in 2000, the Corporation had recorded deferred pension assets of \$23.0 million. The Corporation has been earning an AEUB approved rate of return on these assets through customer rates as the assets form part of the Corporation’s AEUB approved rate base. In the absence of rate regulation, the Corporation would not be able to earn a return on these assets. Consequently, revenues in 2006 would have been \$1.7 million lower (2005 – \$2.1 million lower). On October 11, 2006, the AEUB issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the Corporation to continue to earn an AEUB approved rate of return on the unrecovered portion of these assets over the recovery period. In 2006, the Corporation amortized \$5.1 million (2005 – nil) of the deferred pension asset.

Pursuant to an AEUB decision, the Corporation, as of January 1, 2000, is required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The variances between the amounts accrued and paid are recorded as a regulatory pension asset or liability. At December 31, 2006, the total amount of the regulatory other post employment benefits asset and the regulatory pension asset is \$44.6 million (2005 – \$36.0 million). 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

## **2. Accounting for rate regulated operations (continued)**

plan cost in 2006 would have been \$2.0 million higher (2005 – \$0.7 million higher), and other post employment benefit plan cost in 2006 would have been \$3.5 million higher (2005 – \$3.3 million higher), in the absence of rate regulation.

### ***Deferred electricity costs (recoveries)***

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

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

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

### ***Deferred hearing costs***

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

### ***Reserves for injuries and damages***

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

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

## 2. Accounting for rate regulated operations (continued)

### *Deferred royalty credits*

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

### *Other regulatory assets and liabilities*

Other regulatory assets and liabilities include the following:

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

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

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

## **2. Accounting for rate regulated operations (continued)**

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

### ***Other items affected by rate regulation***

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

The utilities and the generating plants of Alberta Power (2000) follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 6).

## **3. Transfer of retail energy supply businesses**

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

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

### 3. Transfer of retail energy supply businesses (continued)

Although ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if DEML fails to perform. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AEUB to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

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

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

### 4. Regulatory matters

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

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

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

### 5. Interest and other income

	2006	2005
Interest	\$ 4.7	\$ 5.0
Allowance for funds used by regulated operations	9.3	7.0
Gains on dispositions of property, plant and equipment	5.7	1.3
Other income (expense)	2.2	(0.6)
	<b>\$21.9</b>	\$12.7

## 6. Income taxes

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

	2006		2005	
Earnings before income taxes	\$242.9	%	\$269.9	%
Income taxes, at statutory rates	\$ 95.9	39.5	\$109.6	40.6
Federal general tax reduction <sup>(1)</sup>	(12.1)	(5.0)	(12.2)	(4.5)
Manufacturing and processing tax credit	(4.1)	(1.7)	(5.4)	(2.0)
Resource allowance	(0.8)	(0.3)	(2.0)	(0.7)
Crown royalties and other non-deductible Crown payments	0.7	0.3	1.1	0.4
Large Corporations Tax	-	-	4.4	1.6
Change in future income taxes resulting from reduction in tax rates	(4.3)	(1.8)	-	-
Change in method of accounting for future income taxes in certain regulated operations-	(4.0)	(1.7)	-	-
Unrecorded future income taxes relating to regulated operations	2.5	1.0	1.0	0.4
H.R. Milner income tax reassessment	7.4	3.1	-	-
Other	0.6	0.3	3.3	1.2
	<b>81.8</b>	<b>33.7</b>	99.8	37.0
Current income taxes	95.5		95.0	
Future income taxes (recoveries)	\$ (13.7)		\$ 4.8	

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

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

	2006	2005
Property, plant and equipment	\$ 67.3	\$ 84.5
Deferred assets and liabilities	(11.9)	(15.4)
Other	(0.1)	(0.1)
	<b>55.3</b>	69.0
Less: Amounts included in current future income taxes	0.7	4.5
	<b>\$ 54.6</b>	\$ 64.5

Unrecorded future income tax liabilities of the regulated operations amounted to \$141.3 million at December 31, 2006. This balance includes \$14.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

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

Income taxes paid amounted to \$109.9 million (2005 – \$107.9 million).

## 7. Property, plant and equipment

	Composite Depreciation Rates	2006		2005	
		Cost	Accumulated Depreciation	Cost	Accumulated Depreciation
Utilities	3.7%	\$6,480.3	\$2,409.8	\$6,011.8	\$2,239.8
Power Generation	3.1%	1,361.0	697.6	1,329.9	656.3
		<b>\$7,841.3</b>	<b>3,107.4</b>	\$7,341.7	2,896.1
Property, plant and equipment less accumulated depreciation			<b>4,733.9</b>		4,445.6
Unamortized contributions by utility customers for extensions to plant			<b>627.4</b>		567.6
			<b>\$4,106.5</b>		\$3,878.0

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

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of \$109.1 million (2005 – \$91.0 million) and non-depreciable assets of \$33.9 million (2005 – \$32.3 million).

## 8. Other assets

	2006	2005
Accrued pension asset (Note 17)	\$ 0.7	\$ 8.8
Deferred financing charges <sup>(1)</sup>	10.1	9.1
Other <sup>(2)</sup>	17.5	20.3
	<b>\$28.3</b>	\$38.2

<sup>(1)</sup> Amortization of deferred financing charges, which was recorded in interest expense, amounted to \$1.0 million (2005 – \$1.1 million).

<sup>(2)</sup> Amortization of certain other assets, which was recorded in depreciation and amortization, amounted to \$14.7 million (2005 – \$5.7 million).

## 9. Short term advances from parent and affiliate corporations and credit lines

At December 31, 2006, bank indebtedness consists of \$3.3 million (2005 – nil), which represents cheques outstanding in excess of cash in bank.

At December 31, 2006, short term advances from parent corporation consist of promissory notes of \$94.0 million (2005 – nil), at interest rates ranging from 4.33% to 4.35%, maturing in January 2007, and the short term advance from an affiliate corporation consists of a promissory note of \$0.2 million (2005 – \$0.2 million), at an interest rate of 4.23%, repayable on demand.

## 9. Short term advances from parent and affiliate corporations and credit lines (continued)

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

	2006			2005		
	Total	Used	Available	Total	Used	Available
Short term committed	\$300.0	\$14.0	\$286.0	\$300.0	\$ -	\$300.0
Uncommitted	29.1	0.4	28.7	29.1	0.5	28.6
	<b>\$329.1</b>	<b>\$14.4</b>	<b>\$314.7</b>	<b>\$329.1</b>	<b>\$0.5</b>	<b>\$328.6</b>

All of the \$14.4 million used at December 31, 2006 represents outstanding letters of credit.

## 10. Long term debt

	2006	2005
<b>Long term debt</b>		
Debentures – unsecured		
2001 4.84% due November 2006	\$ -	\$ 175.0
2002 4.801% due November 2007	50.0	50.0
2000 6.97% due June 2008	100.0	100.0
1989 Series 10.20% due November 2009	125.0	125.0
1990 Series 11.40% due August 2010	125.0	125.0
2000 7.05% due June 2011	100.0	100.0
2004 5.096% due November 2014	100.0	100.0
2002 6.145% due November 2017	150.0	150.0
2004 5.432% due January 2019	180.0	180.0
1999 6.8% due August 2019	300.0	300.0
1990 Second Series 11.77% due November 2020	100.0	100.0
2006 4.801% due November 2021	160.0	-
1991 Series 9.92% due April 2022	125.0	125.0
1992 Series 9.40% due May 2023	100.0	100.0
2004 5.896% due November 2034	200.0	200.0
2005 5.183% due November 2035	185.0	185.0
2006 5.032% due November 2036	160.0	-
Other long term obligation, at 5.0%, due June 2007, unsecured	4.5	4.5
	<b>2,264.5</b>	<b>2,119.5</b>
<b>Long term debt to parent corporation</b>		
Non-interest bearing promissory note, unsecured	3.0	3.0
	<b>\$2,267.5</b>	<b>\$2,122.5</b>

### Minimum debt repayments

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

2007	2008	2009	2010	2011
\$54.5	\$100.0	\$125.0	\$125.0	\$100.0

The amount due in 2007 is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

## 10. Long term debt (continued)

### *Interest expense*

Interest expense is as follows:

	2006	2005
Long term debt	\$155.7	\$149.1
Notes payable	0.3	-
Bank indebtedness	0.6	0.5
Amortization of deferred financing charges	1.0	1.1
Interest on H.R. Milner income tax reassessment (Note 6)	8.3	-
	<b>\$165.9</b>	<b>\$150.7</b>

Interest paid amounted to \$164.4 million (2005 – \$149.5 million).

### *Fair values*

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

	2006	2005
Long term debt – Fixed rate	\$2,633.1	\$2,546.2
Long term debt to parent corporation – Fixed rate	\$ 3.0	\$ 3.0

## 11. Deferred credits

	2006	2005
Deferred availability incentives	\$ 39.6	\$ 59.7
Asset retirement obligations	39.9	34.2
Accrued other post employment benefits liability (Note 17)	27.9	22.3
Deferred revenues	3.2	6.6
Other	14.9	19.4
	<b>\$125.5</b>	<b>\$142.2</b>

### *Deferred availability incentives*

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

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

## 11. Deferred credits (continued)

### *Asset retirement obligations*

Changes in asset retirement obligations are summarized below:

	2006	2005
Obligations at beginning of year	\$34.2	\$27.4
Obligations incurred	3.7	5.1
Accretion expense	2.0	1.7
Obligations at end of year	\$39.9	\$34.2

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately \$67 million, which will be incurred between 2007 and 2026. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.8%.

## 12. Equity preferred shares to parent corporation

### *Authorized and issued*

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

Issued:

	Stated Value (dollars)	Redemption Dates	2006		2005	
			Shares	Amount	Shares	Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	\$25.00	Open	2,277,675	\$ 56.9	2,277,675	\$ 56.9
5.3% Series R	\$25.00	Open	2,146,730	53.7	2,146,730	53.7
6.6% Series S	\$25.00	Open	635,700	15.9	635,700	15.9
Perpetual Cumulative Second Preferred Shares						
4.35% Series U	\$25.00	December 2, 2011	800,000	20.0	800,000	20.0
5.25% Series V	\$25.00	October 3, 2007	4,400,000	110.0	4,400,000	110.0
				\$256.5		\$256.5

The dividends payable on the Series 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 Canadian Utilities Limited.

### *Fair values*

Fair values for preferred shares determined using quoted market prices for the same or similar issues are \$261.9 million (2005 – \$261.9 million).

### *Redemption privileges*

The preferred shares are redeemable on the dates specified above at the option of the Corporation at the stated value plus accrued and unpaid dividends.

### 13. Class A and Class B shares

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:	124	\$252.7	76	\$154.9	200	\$407.6

### 14. Stock based compensation plans

#### *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 prices 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 the Class I Non-Voting shares, respectively, over the base value of the share appreciation rights exercised.

Share appreciation rights expense amounted to \$0.2 million (2005 – \$0.2 million).

### 15. Changes in non-cash working capital

	2006	2005
<i>Operating activities, changes related to:</i>		
Accounts receivable	\$(27.3)	\$ (7.0)
Accounts receivable from parent and affiliate corporations	(5.3)	9.0
Inventories	3.6	93.3
Regulatory assets	(10.6)	(1.4)
Prepaid expenses	(2.7)	(0.1)
Accounts payable and accrued liabilities	(4.9)	1.1
Accounts payable to parent and affiliate corporations	1.7	3.1
Income taxes	(6.6)	(6.1)
Future income taxes	(3.9)	4.8
Regulatory liabilities	(5.2)	(7.9)
	<b>\$(61.2)</b>	<b>\$ 88.8</b>
<i>Investing activities, changes related to:</i>		
Inventories	\$ (8.1)	\$ (1.5)
Prepaid expenses	(0.3)	-
Accounts payable and accrued liabilities	(1.0)	10.2
Income taxes	(3.7)	(11.0)
	<b>\$(13.1)</b>	<b>\$ (2.3)</b>
<i>Financing activities, changes related to:</i>		
Accounts receivable	\$ (0.1)	\$ (0.4)

## 16. Related party transactions

Entity	Relationship	Transaction	Recorded As	2006	2005
Canadian Utilities Limited	Parent	Sale of electricity and natural gas, lease of land, rent and office services	Revenues	\$ 0.6	\$ 0.5
		Rent and aircraft usage	Selling and administrative	7.7	7.8
		Purchase of equipment and leasehold improvements	Property, plant and equipment	0.9	0.7
ATCO Ltd. and ATCO Investments Ltd.	Affiliates	Corporate signature rights and rent	Selling and administrative	3.6	2.6
ASHCOR Technologies Ltd., ATCO Frontec Corp., ATCO I-Tek Inc., ATCO Midstream Ltd., ATCO Power Ltd., ATCO Utility Services Ltd., and Genics Inc.	Affiliates	Natural gas storage, transportation and other gas services, sale of ash, rent and office services, payroll and accounting services	Revenues	27.5	23.6
		Purchase and storage of natural gas	Natural gas supply	2.5	2.1
		Purchase of natural gas	Operation and maintenance	10.9	12.0
		Purchase of natural gas	Regulatory assets	9.6	-
		Computer operations and systems development, call centre and customer billing services, property management and security services	Operation and maintenance, selling and administrative	73.5	71.0
		North Warning System joint venture earnings	Other income	0.2	0.3
		Purchase of equipment, capitalized costs and capitalized software	Property, plant and equipment	25.9	23.1

The Corporation incurred advertising and promotion expenses from an entity related through common control totaling \$0.3 million (2005 – \$0.3 million).

At December 31, 2006, accounts receivable due from related parties amounted to \$8.5 million (2005 – \$3.2 million) and accounts payable due to related parties amounted to \$28.1 million (2005 – \$26.4 million).

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

## 17. Employee future benefits

The Corporation, together with Canadian Utilities Limited and its subsidiary corporations, 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

## 17. Employee future benefits (continued)

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.

Contributions to the Group Plan, which is accounted for as a defined contribution pension plan, are expensed as paid. Other post employment benefit and certain other group defined benefit pension plans, which the Corporation funds out of general revenues, are administered on a combined basis with Canadian Utilities Limited and its subsidiary corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for each plan as a whole; for certain other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans. 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 regulatory assets.

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

	2006		2005	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Benefit plan cost:</i>				
Total cost	\$ 11.8	\$ 8.1	\$ 5.0	\$ 7.4
Less: Capitalized	1.9	2.7	1.4	2.3
Less: Regulatory deferral <sup>(1)</sup>	2.0	3.5	0.7	3.3
Net cost recognized <sup>(2)</sup>	\$ 7.9	\$ 1.9	\$ 2.9	\$ 1.8
<i>Accrued benefit plan assets and liabilities:</i>				
Accrued asset (liability) at beginning of year	\$ 8.8	\$(22.3)	\$ 9.8	\$(17.1)
Total cost	(11.8)	(8.1)	(5.0)	(7.4)
Benefit payments	3.7	2.5	4.0	2.2
Accrued asset (liability) at end of year (Notes 8, 11)	\$ 0.7	\$(27.9)	\$ 8.8	\$(22.3)
<i>Regulatory benefit plan assets <sup>(1)</sup> (Note 2):</i>				
Regulatory asset at beginning of year	\$ 14.0	\$ 22.0	\$13.0	\$ 16.8
Regulatory cost deferral	2.0	3.5	0.7	3.3
Regulatory cost capitalized	1.0	2.1	0.3	1.9
Regulatory asset at end of year	\$ 17.0	\$ 27.6	\$14.0	\$ 22.0

<sup>(1)</sup> The regulatory deferral of benefit plan cost and the regulatory asset reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

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

In the unaudited three months ended December 31, 2006, net cost of \$5.7 million (2005 – \$0.9 million) was recognized for pension benefit plans and net cost of \$0.2 million (2005 – \$0.3 million) was recognized for other post employment benefit plans.

## 17. Employee future benefits (continued)

### *Weighted average assumptions*

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

(1) The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 8.5% for 2006 grading down over 7 years to 4.5% (2005 – 9.2% for 2005 grading down over 8 years to 4.5%), and, for other medical and dental costs, 4.0% for 2006 and thereafter (2005 – 4.0% for 2005 and thereafter).

### *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.

## 18. Risk management and financial instruments

The Corporation is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. 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.

### *Foreign exchange rate risk*

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. At December 31, 2006, the contracts consist of purchases of \$0.2 million U.S. (2005 – \$0.2 million).

### *Energy commodity price risk*

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

## 18. Risk management and financial instruments (continued)

### *Fair values*

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

	2006			2005		
	Notional Principal	Fair Value (Payable) Receivable	Maturity	Notional Principal	Fair Value (Payable) Receivable	Maturity
Foreign exchange forward contracts	\$0.3	Nil	2007	\$0.3	Nil	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.

## 19. Commitments and contingencies

### *Commitments*

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

	2007	2008	2009	2010	2011	Total of All Subsequent Years
Operating leases <sup>(1)</sup>	\$ 9.4	\$ 8.3	\$ 4.4	\$ 3.9	\$ 2.6	\$ 0.5
Purchase obligations:						
Coal purchase contracts <sup>(2)</sup>	47.7	48.9	50.3	51.8	53.4	355.6
Natural gas purchase contracts	0.5	0.5	0.5	0.5	0.5	2.0
	\$57.6	\$57.7	\$55.2	\$56.2	\$56.5	\$358.1

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

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

### *Contingencies*

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

## 19. Commitments and contingencies (continued)

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.

## 20. Segmented information

### *Description of segments*

The Corporation operates in the following business segments:

The **Utilities** segment 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, and the regulated transmission and distribution of water by CU Water.

The **Power Generation** segment consists of the regulated supply of electricity by Alberta Power (2000).

### *Segmented results – Three months ended December 31*

<b>2006</b> 2005	Utilities	Power Generation	Corporate and Other	Intersegment Eliminations	Consolidated
<i>(Unaudited)</i>					
Revenues – external	<b>\$319.0</b> \$305.0	<b>\$72.7</b> \$77.2	\$ - \$ -	\$ - \$ -	<b>\$391.7</b> \$382.2
Revenues – intersegment <sup>(1)</sup>	<b>0.1</b> 0.2	- -	- -	<b>(0.1)</b> (0.2)	- -
Revenues	<b>\$319.1</b> \$305.2	<b>\$72.7</b> \$77.2	\$ - \$ -	<b>\$(0.1)</b> \$(0.2)	<b>\$391.7</b> \$382.2
Earnings attributable to Class A and Class B shares	<b>\$ 43.1</b> \$ 32.4	<b>\$ 4.7</b> \$13.1	\$ - \$0.1	\$ - \$ -	<b>\$ 47.8</b> \$ 45.6

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

## 20. Segmented information (continued)

### Segmented results – Year ended December 31

2006 2005	Utilities	Power Generation	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	<b>\$1,109.0</b> \$1,194.5	<b>\$292.8</b> \$295.5	\$ - \$ -	\$ - \$ -	<b>\$1,401.8</b> \$1,490.0
Revenues – intersegment <sup>(1)</sup>	<b>0.2</b> 0.3	- -	- -	<b>(0.2)</b> (0.3)	- -
Revenues	<b>1,109.2</b> 1,194.8	<b>292.8</b> 295.5	- -	<b>(0.2)</b> (0.3)	<b>1,401.8</b> 1,490.0
Operating expenses	<b>601.9</b> 716.4	<b>145.2</b> 130.6	- -	<b>(0.2)</b> (0.3)	<b>746.9</b> 846.7
Depreciation and amortization	<b>220.0</b> 189.1	<b>48.0</b> 46.3	- -	- -	<b>268.0</b> 235.4
Interest expense	<b>132.3</b> 124.7	<b>33.6</b> 26.3	<b>155.6</b> 149.1	<b>(155.6)</b> (149.4)	<b>165.9</b> 150.7
Interest and other income	<b>(20.3)</b> (11.8)	<b>(1.5)</b> (0.9)	<b>(155.7)</b> (149.4)	<b>155.6</b> 149.4	<b>(21.9)</b> (12.7)
Earnings before income taxes	<b>175.3</b> 176.4	<b>67.5</b> 93.2	<b>0.1</b> 0.3	- -	<b>242.9</b> 269.9
Income taxes	<b>44.9</b> 60.1	<b>36.9</b> 39.6	- 0.1	- -	<b>81.8</b> 99.8
	<b>130.4</b> 116.3	<b>30.6</b> 53.6	<b>0.1</b> 0.2	- -	<b>161.1</b> 170.1
Dividends on equity preferred shares to parent corporation	<b>10.4</b> 10.4	<b>3.6</b> 3.6	- -	- -	<b>14.0</b> 14.0
Earnings attributable to Class A and Class B shares	<b>\$ 120.0</b> \$ 105.9	<b>\$ 27.0</b> \$ 50.0	<b>\$ 0.1</b> \$ 0.2	<b>\$ -</b> \$ -	<b>\$ 147.1</b> \$ 156.1
Total assets	<b>\$3,778.6</b> \$3,524.9	<b>\$744.9</b> \$771.3	<b>\$ 0.2</b> \$ 4.8	<b>\$ -</b> \$ (8.1)	<b>\$4,523.7</b> \$4,292.9
Purchase of property, plant and equipment	<b>\$ 505.0</b> \$ 471.9	<b>\$ 31.1</b> \$ 26.5	<b>\$ -</b> \$ -	<b>\$ -</b> \$ -	<b>\$ 536.1</b> \$ 498.4

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