



CONSOLIDATED FINANCIAL STATEMENTS

**FOR THE NINE MONTHS ENDED
SEPTEMBER 30, 2004**

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

	Note	Three Months Ended September 30		Nine Months Ended September 30	
		2004	2003	2004	2003
			(Restated, Notes 1, 5)		(Restated, Notes 1, 5)
			<i>(Unaudited)</i>		<i>(Unaudited)</i>
Revenues		\$ 266.3	\$ 430.2	\$1,707.0	\$2,118.1
Costs and expenses					
Natural gas supply	2	(4.6)	113.1	703.0	1,021.2
Purchased power		8.8	45.3	80.4	163.0
Operation and maintenance		77.6	73.7	227.8	225.2
Selling and administrative		43.9	51.7	145.5	147.2
Depreciation and amortization		48.2	47.0	158.9	150.6
Interest		34.9	36.1	107.8	108.1
Franchise fees		18.9	15.6	95.9	92.1
		227.7	382.5	1,519.3	1,907.4
Gain on transfer of retail energy supply businesses	3	38.6	47.7	187.7	210.7
Interest and other income		1.8	1.5	5.0	4.1
Earnings before income taxes		40.4	49.2	256.0	214.8
Income taxes		12.9	20.5	77.4	83.9
		27.5	28.7	178.6	130.9
Dividends on equity preferred shares to parent corporation		3.5	3.5	10.5	10.5
Earnings attributable to Class A and Class B shares	3	24.0	25.2	168.1	120.4
Retained earnings at beginning of period as restated	4	1,106.2	986.4	1,003.4	925.2
		1,130.2	1,011.6	1,171.5	1,045.6
Dividends on Class A and Class B shares		59.5	15.1	100.8	49.1
Retained earnings at end of period		\$1,070.7	\$ 996.5	\$1,070.7	\$ 996.5

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

	September 30		December 31
	2004	2003	2003
		(Restated, Notes 1, 5)	(Restated, Notes 1, 5)
	<i>(Unaudited)</i>		<i>(Audited)</i>
ASSETS			
Current assets			
Cash and short term investments	\$ 22.2	\$ 3.5	\$ 42.8
Accounts receivable	204.6	242.0	429.3
Accounts receivable from parent and affiliate corporations	8.9	10.0	4.0
Inventories	149.5	151.4	155.9
Income taxes recoverable	-	5.0	21.4
Deferred natural gas costs	-	-	27.2
Deferred electricity costs	-	2.9	-
Prepaid expenses	16.4	19.5	13.0
	401.6	434.3	693.6
Property, plant and equipment	3,572.5	3,369.3	3,438.5
Other assets	57.4	71.2	73.3
	\$4,031.5	\$3,874.8	\$4,205.4
LIABILITIES AND SHARE OWNER'S EQUITY			
Current liabilities			
Short term advances from parent and affiliate corporations	\$ 62.3	\$ 97.9	\$ 285.0
Accounts payable and accrued liabilities	136.2	157.8	284.1
Accounts payable to parent and affiliate corporations	16.7	59.8	80.7
Income taxes payable	9.9	-	-
Future income taxes	12.8	3.4	11.5
Deferred natural gas cost recoveries	0.2	1.2	-
Deferred electricity cost recoveries	25.2	-	1.0
Notes payable	96.0	42.0	-
	359.3	362.1	662.3
Future income taxes	66.7	76.0	80.0
Deferred credits	108.2	93.6	113.1
Long term debt	1,762.5	1,682.5	1,682.5
Equity preferred shares to parent corporation	256.5	256.5	256.5
Class A and Class B share owner's equity			
Class A and Class B shares	407.6	407.6	407.6
Retained earnings	1,070.7	996.5	1,003.4
	1,478.3	1,404.1	1,411.0
	\$4,031.5	\$3,874.8	\$4,205.4

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

	Note	Three Months Ended September 30		Nine Months Ended September 30	
		2004	2003	2004	2003
		(Restated, Notes 1, 5) <i>(Unaudited)</i>		(Restated, Notes 1, 5) <i>(Unaudited)</i>	
Operating activities					
Earnings attributable to Class A and Class B shares		\$ 24.0	\$ 25.2	\$ 168.1	\$ 120.4
Adjustments for:					
Depreciation and amortization		48.2	47.0	158.9	150.6
Future income taxes		(1.2)	0.9	0.1	1.1
Gain on transfer of retail energy supply businesses					
- net of income taxes	3	-	-	(55.1)	-
Deferred availability incentives		15.8	(2.8)	(5.3)	(0.2)
Other		0.7	1.0	4.0	3.9
Cash flow from operations		87.5	71.3	270.7	275.8
Changes in non-cash working capital		(54.0)	42.4	134.8	14.0
		33.5	113.7	405.5	289.8
Investing activities					
Purchase of property, plant and equipment		(110.3)	(105.1)	(322.2)	(242.5)
Proceeds on transfer of retail energy supply businesses					
- net of income taxes	3	-	-	22.5	-
Proceeds (costs) on disposal of property, plant and equipment		(3.5)	(0.8)	(3.6)	5.4
Contributions by utility customers for extensions to plant		11.2	9.9	40.6	32.5
Non-current deferred electricity costs		2.0	3.9	(9.9)	8.8
Changes in non-cash working capital		(8.6)	1.7	(3.0)	(36.3)
Other		0.6	(2.2)	(2.1)	(2.9)
		(108.6)	(92.6)	(277.7)	(235.0)
Financing activities					
Change in notes payable		96.0	42.0	96.0	42.0
Deferred electricity cost obligation		-	(15.9)	-	(51.0)
Issue of long term debt		-	-	180.0	-
Repayment of long term debt		-	(60.0)	(100.0)	(60.0)
Repayment of long term debt to parent corporation		-	(1.0)	-	(1.0)
Dividends paid to Class A and Class B share owner		(59.5)	(15.1)	(100.8)	(49.1)
Changes in non-cash working capital		-	-	-	1.0
Other		0.1	(0.1)	(0.9)	(0.2)
		36.6	(50.1)	74.3	(118.3)
Cash position ⁽¹⁾					
Increase (decrease)		(38.5)	(29.0)	202.1	(63.5)
Beginning of period		(1.6)	(65.4)	(242.2)	(30.9)
End of period		\$ (40.1)	\$ (94.4)	\$ (40.1)	\$ (94.4)

⁽¹⁾ Cash position includes cash and short term investments less short term advances from parent and affiliate corporations.

CU INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
SEPTEMBER 30, 2004
(Unaudited, Tabular Amounts in Millions of Canadian Dollars)

1. Financial statement presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and should be read in conjunction with the Corporation’s December 31, 2003 consolidated financial statements and related notes. These interim financial statements have been prepared using the same accounting policies as used in the financial statements for the year ended December 31, 2003, except as described below.

Effective January 1, 2004, the Corporation retroactively adopted the Canadian Institute of Chartered Accountants (“CICA”) recommendations on accounting for asset retirement obligations as described in Note 5. The prior year’s financial statements have been restated for the change in the method of accounting for asset retirement obligations.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses to be 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. This change in accounting had no effect on earnings for the three and nine months ended September 30, 2004.

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations that define the primary sources of GAAP. While the recommendations encourage the application of the primary sources of GAAP to all operations, the recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP. The Corporation has chosen to retain its existing accounting policies for its regulated operations, which are permitted by GAAP, as described in Note 2.

Due to the seasonal nature of the Corporation’s operations and the timing of rate decisions, the consolidated statements of earnings and retained earnings for the three and nine months ended September 30, 2004 and September 30, 2003 are not necessarily indicative of operations on an annual basis.

Certain 2003 figures have been reclassified to conform to the current presentation.

2. 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., CU Water and the generating plants of Alberta Power (2000) are collectively referred to in these consolidated financial statements as the “regulated operations”.

The generating plants of Alberta Power (2000) were regulated by the Alberta Energy and Utilities Board (“AEUB”) until December 31, 2000 but are now governed by legislatively mandated Power Purchase Arrangements (“PPA”) 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.

2. Regulation (continued)

Differences between the Corporation's accounting policies for its regulated operations and the primary sources of GAAP occur when the AEUB renders its decisions on the Corporation's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Corporation has achieved proper matching of revenues and expenses. Where regulatory practice dictates, the Corporation defers certain costs or revenues as assets or liabilities in the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any differences between the amounts deferred and amounts approved by the AEUB for collection or refund in future customer rates are recognized in earnings in the period that the AEUB renders a decision. The Corporation anticipates that there would be no material differences between the amounts approved by the AEUB for collection or refund and the amounts included in assets or liabilities on the balance sheet.

The significant accounting policies that differ from those required by the primary sources of GAAP are described as follows:

- a) *Depreciation* – Depreciation rates for regulated assets are approved by the AEUB or, in the case of Alberta Power (2000)'s generating plants, are determined by the PPA's.
- b) *Future removal and site restoration costs* – Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, include a provision for future removal costs and site restoration costs. 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.
- c) *Allowance for funds used during construction* – Certain 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.
- d) *Employee future benefits* – Costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), are recognized in earnings when paid rather than accrued. The differences between the amounts accrued and paid are deferred.

Significant accounting policies that are consistent with those required by the primary sources of GAAP for items that are subject to regulatory approval include:

- a) *Purchased power* – Purchased power expense for the regulated operations 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.
- b) *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.
- c) Certain costs as required or permitted by the AEUB are deferred for recovery through future rates.

Significant accounting policies that pertained to the retail energy supply businesses that were transferred as of May 4, 2004 (see Note 3) and were consistent with those required by the primary sources of GAAP for items that were subject to regulatory approval included:

- a) *Natural gas supply* – Natural gas supply expense (income) 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 AEUB was obtained for refund to or collection from customers and revenues and natural gas supply expense (income) was adjusted accordingly.

2. Regulation (continued)

Natural gas supply expense (income) for the three and nine months ended September 30, 2004 reflects the final adjustment to natural gas supply pursuant to the transfer of ATCO Gas' natural gas purchase contracts that was completed by September 30, 2004 (see Note 3).

- b) *Purchased power* – 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.

3. Transfer of retail energy supply businesses

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. Proceeds of the transfer were \$90 million, of which \$45 million was paid at closing, with the remainder to be paid 12 months following closing. 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. This transfer increased earnings for the nine months ended September 30, 2004 by \$55.1 million. The Corporation's revenues and natural gas supply and purchased power costs after May 4, 2004 will be reduced accordingly. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEMML pending the transfer of the relevant ATCO Gas natural gas purchase contracts to DEMML. This transfer of contracts was completed by September 30, 2004. There will be no 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 have transferred to DEMML 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, DEMML commenced supplying natural gas and electricity at regulated rates to residential, farm and small business customers in the ATCO Gas and ATCO Electric service areas and billing customers for their natural gas and electricity service.

If DEMML 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 DEMML is able to perform such functions. In certain events (including where DEMML 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 purchase price to DEMML by ATCO Gas and/or ATCO Electric. In certain circumstances, if DEMML is restrained or prohibited from carrying out the transferred functions, all functions will revert to ATCO Gas and ATCO Electric and a portion of the purchase price will be refunded to DEMML, depending upon the timing of any such reversion.

Centrica plc, DEMML's parent, has provided a \$300 million guarantee supported by a \$235 million letter of credit in respect of DEMML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services Ltd., an affiliate corporation, 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 DEMML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the purchase price to DEMML 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.

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.

3. Transfer of retail energy supply businesses (continued)

In December 2003, the AEUB issued a decision approving the transfer of the retail operations of ATCO Gas and ATCO Electric to DEML. The City of Calgary filed for leave to appeal the AEUB decision, including the allocation of proceeds to ATCO Gas and ATCO Electric. On June 30, 2004, the Alberta Court of Appeal dismissed the City of Calgary's application for leave to appeal.

4. Retained earnings at beginning of period as restated

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	2004	2003
Retained earnings at beginning of period as previously reported	\$1,106.2	\$990.1	\$1,007.1	\$929.3
Adjustment to retained earnings for prior years' effect of change in method of accounting for asset retirement obligations (after income taxes)	-	(3.7)	(3.7)	(4.1)
Retained earnings at beginning of period as restated	\$1,106.2	\$986.4	\$1,003.4	\$925.2

5. Asset retirement obligations

The CICA recommendations on accounting for asset retirement obligations require the Corporation to identify 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, 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. Prior to January 1, 2004, site restoration and removal costs that are now accounted for as asset retirement obligations were accrued over the estimated remaining useful lives of the assets.

Asset retirement obligations for regulated natural gas and electric transmission and distribution assets were 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).

The effect of adopting these recommendations is presented as increases (decreases) below:

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	2004	2003
<i>Statement of earnings</i>				
Depreciation and amortization	\$(0.2)	\$(0.4)	\$(0.8)	\$(1.5)
Accretion expense, included in depreciation and amortization	0.3	0.4	1.1	1.1
Earnings attributable to Class A and Class B shares	\$(0.1)	\$ -	\$(0.3)	\$ 0.4
				January 1 2003
<i>Balance sheet</i>				
Retirement assets and site restoration and removal costs, included in property, plant and equipment				\$20.4
Asset retirement obligations, included in deferred credits				24.5
Retained earnings at beginning of period				(4.1)

5. Asset retirement obligations (continued)

Changes in asset retirement obligations are summarized below:

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	2004	2003
Obligations at beginning of period	\$26.7	\$25.2	\$25.9	\$24.5
Accretion expense	0.3	0.4	1.1	1.1
Obligations at end of period	\$27.0	\$25.6	\$27.0	\$25.6

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately \$63 million, which will be incurred between 2005 and 2026. A weighted average discount rate of 5.9% was used to calculate the fair value of the asset retirement obligations.

6. Employee future benefits

In the three months ended September 30, 2004, net expense of \$0.6 million (2003 – \$0.8 million) was recognized for pension benefit plans and net expense of \$0.4 million (2003 – \$0.4 million) was recognized for other post employment benefit plans.

In the nine months ended September 30, 2004, net expense of \$1.6 million (2003 – \$1.8 million) was recognized for pension benefit plans and net expense of \$1.3 million (2003 – \$1.2 million) was recognized for other post employment benefit plans.

7. Segmented information

The Corporation operates in the following business segments:

Utilities (ATCO Gas, ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, ATCO Pipelines, CU Water). This segment was formerly known as Natural Gas and Electric; its composition has remained unchanged.

Power Generation (Alberta Power (2000)).

Segmented results – Three months ended September 30

2004 2003	Utilities	Power Generation	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	\$193.7 \$349.3	\$72.6 \$80.9	\$ - \$ -	\$ - \$ -	\$266.3 \$430.2
Revenues – intersegment	- 1.9	- -	- -	- (1.9)	- -
Revenues	\$193.7 \$351.2	\$72.6 \$80.9	\$ - \$ -	\$ - \$(1.9)	\$266.3 \$430.2
Earnings attributable to Class A and Class B shares	\$ 10.1 \$ 11.8	\$13.5 \$13.4	\$0.4 \$ -	\$ - \$ -	\$ 24.0 \$ 25.2

7. Segmented information (continued)

Segmented results – Nine months ended September 30

2004 2003	Utilities	Power Generation	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	\$1,488.8 \$1,881.0	\$218.2 \$237.1	\$ - \$ -	\$ - \$ -	\$1,707.0 \$2,118.1
Revenues – intersegment	2.3 4.8	- -	- -	(2.3) (4.8)	- -
Revenues	\$1,491.1 \$1,885.8	\$218.2 \$237.1	\$ - \$ -	\$(2.3) \$(4.8)	\$1,707.0 \$2,118.1
Earnings attributable to Class A and Class B shares	\$ 130.0 \$ 79.6	\$ 37.1 \$ 40.8	\$ 1.0 \$ -	\$ - \$ -	\$ 168.1 \$ 120.4
Total assets	\$3,256.0 \$3,084.8	\$774.5 \$790.3	\$1.2 \$0.4	\$(0.2) \$(0.7)	\$4,031.5 \$3,874.8

8. Regulatory matters

For 2002, ATCO Electric's rate of return on common equity was 10.5% and the common equity ratio was 37% for transmission operations and 43% for distribution 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 is allowed to earn a return on by \$83.0 million for 2003. ATCO Electric, as directed by the AEUB, refiled the 2003 and 2004 revenue requirements, incorporating the findings in the decision. In a decision dated February 17, 2004, the AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years, accepting the refiling with no material changes. Certain matters relating to transactions with affiliates will be addressed in separate proceedings. In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, a return on common equity of 9.60% for 2004 and a common equity ratio of 33% for ATCO Electric's transmission operations and 37% for its distribution operations beginning in 2004. These increases in the common equity ratios increased the common equity that ATCO Electric is allowed to earn a return on by \$22.3 million for 2004. In summary, the negative impacts of the 2003/2004 general tariff decision and the generic cost of capital decision reduced the common equity that ATCO Electric is allowed to earn a return on by \$60.7 million over the two years, 2003 and 2004.

In December 2002, the AEUB issued a decision approving rates for ATCO Gas on an interim basis effective January 1, 2003. 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. ATCO Gas, as directed by the AEUB, refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. In a decision dated June 15, 2004, the AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years, accepting the refiling with no material changes. Certain matters relating to transactions with affiliates will be addressed in separate proceedings. In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Gas' common equity ratio of 38% beginning in 2005. As ATCO Gas' return on common equity for 2004 was already established, the standardized approach approved by the AEUB for determining the return on common equity (as described below) will be applied beginning in 2005.

8. Regulatory matters (continued)

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. ATCO Pipelines, as directed by the AEUB, refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. In a decision dated March 9, 2004, the AEUB approved interim rates to be effective from March 1, 2004 to October 31, 2004. In a decision dated April 30, 2004, the AEUB accepted the refiling of the revenue requirements for the 2003 and 2004 test years with no material changes. In a decision dated July 13, 2004, the AEUB awarded additional revenue with respect to the revenue forecasts of certain industrial customers. Certain matters relating to transactions with affiliates will be addressed in separate proceedings. In a decision dated July 2, 2004, the AEUB issued its generic cost of capital decision which approved, among other things, ATCO Pipelines' return on common equity of 9.60% for 2004 and a common equity ratio of 43% beginning in 2004.

The generic cost of capital 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 Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year 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.

9. Contingency

As a result of recent 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.