An ATCO Company

CU INC.

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2008

PRICEWATERHOUSECOOPERS

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Auditors' Report

To the Share Owner of
CU Inc.

We have audited the consolidated balance sheets of CU Inc. as at December 31, 2008 and 2007 and the consolidated statements of earnings and retained earnings, cash flows and comprehensive income for each of the years in the two year period ended December 31, 2008. These consolidated financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2008 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 17, 2009

CU Inc.
Consolidated Statement of Earnings and Retained Earnings
(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 2008	2007	Year Ended December 31 2008	2007
		(Unaudited)			
Revenues	3	**$ 413.5**	$ 394.2	**$1,573.4**	$1,414.2
Costs and expenses					
Natural gas supply		**0.5**	0.4	**2.6**	2.1
Purchased power		**14.9**	13.6	**54.1**	49.9
Operation and maintenance		**110.2**	106.6	**409.2**	383.6
Selling and administrative		**68.4**	61.7	**233.9**	208.0
Depreciation and amortization		**76.2**	73.9	**299.1**	271.2
Interest	5, 9	**47.4**	42.6	**181.5**	165.8
Franchise fees		**42.5**	37.4	**175.2**	151.2
		360.1	336.2	**1,355.6**	1,231.8
		53.4	58.0	**217.8**	182.4
Interest and other income	4	**8.1**	6.6	**26.5**	18.0
Earnings before income taxes		**61.5**	64.6	**244.3**	200.4
Income taxes	3, 5	**0.5**	8.2	**32.7**	9.9
		61.0	56.4	**211.6**	190.5
Dividends on equity preferred shares		**1.3**	1.3	**5.3**	3.7
Dividends on equity preferred shares to parent corporation		**1.5**	1.7	**6.0**	9.5
Earnings attributable to Class A and Class B shares		**58.2**	53.4	**200.3**	177.3
Retained earnings at beginning of period		**1,389.8**	1,209.3	**1,262.7**	1,085.4
		1,448.0	1,262.7	**1,463.0**	1,262.7
Dividends on Class A and Class B shares		**44.8**	-	**59.8**	-
Retained earnings at end of period		**$1,403.2**	$1,262.7	**$1,403.2**	$1,262.7

CU Inc.
Consolidated Balance Sheet
(Millions of Canadian Dollars)

	Note	December 31 **2008**	2007
ASSETS			
Current assets			
Short term advance to parent corporation		**$ 6.0**	$ 8.0
Accounts receivable		**247.5**	241.3
Accounts receivable from parent and affiliate corporations		**10.2**	2.9
Inventories	6	**77.0**	73.0
Income taxes recoverable	3, 5	**6.0**	9.8
Future income taxes	5	**5.6**	-
Regulatory assets	2	**55.8**	30.0
Prepaid expenses		**7.7**	11.3
		415.8	376.3
Property, plant and equipment	7	**4,882.7**	4,388.0
Regulatory assets	2	**87.6**	95.6
Other assets		**20.0**	20.0
		$5,406.1	$4,879.9
LIABILITIES AND SHARE OWNER'S EQUITY			
Current liabilities			
Bank indebtedness	8	**$ 15.0**	$ 6.9
Short term advances from parent and affiliate corporations	8	**-**	0.8
Accounts payable and accrued liabilities		**321.7**	219.0
Accounts payable to parent and affiliate corporations		**34.5**	35.6
Future income taxes	5	**-**	2.1
Regulatory liabilities	2	**29.3**	5.9
Derivative liabilities	18	**-**	0.1
		400.5	270.4
Future income taxes	3, 5	**24.6**	26.2
Regulatory liabilities	2	**37.1**	36.7
Deferred credits	10	**199.6**	166.7
Long term debt	9	**2,683.2**	2,459.4
Equity preferred shares	11	**115.0**	115.0
Equity preferred shares to parent corporation	11	**130.0**	130.0
Class A and Class B share owner's equity			
Class A and Class B shares	12	**412.9**	412.9
Retained earnings		**1,403.2**	1,262.7
Accumulated other comprehensive income	19	**-**	(0.1)
Retained earnings and accumulated other comprehensive income		**1,403.2**	1,262.6
		1,816.1	1,675.5
		$5,406.1	$4,879.9

[Original signed by K.M. Watson]
DIRECTOR

[Original signed by R.J. Urwin]
DIRECTOR

CU Inc.
Consolidated Statement of Cash Flows
(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 2008	Three Months Ended December 31 2007	Year Ended December 31 2008	Year Ended December 31 2007
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 58.2**	$ 53.4	**$ 200.3**	$ 177.3
Adjustments for:					
Depreciation and amortization		**76.2**	73.9	**299.1**	271.2
Future income taxes	3	**(10.0)**	(4.6)	**(14.1)**	(3.4)
Deferred availability incentives		**16.1**	4.5	**19.5**	2.2
Other post employment benefit adjustment	17	**(2.1)**	-	**(2.1)**	-
Other		**2.7**	1.6	**2.5**	5.5
Funds generated by operations		**141.1**	128.8	**505.2**	452.8
Changes in non-cash working capital	15	**(53.0)**	(14.1)	**1.5**	14.3
Cash flow from operations		**88.1**	114.7	**506.7**	467.1
Investing activities					
Purchase of property, plant and equipment		**(315.3)**	(188.6)	**(878.4)**	(615.4)
Costs on disposal of property, plant and equipment		**(11.0)**	(8.9)	**(20.0)**	(17.1)
Contributions by utility customers for extensions to plant		**38.4**	25.8	**176.3**	91.2
Non-current deferred electricity costs		**17.6**	(4.5)	**10.5**	(9.6)
Deferred natural gas transmission costs		**-**	(0.6)	**(11.9)**	(3.1)
Changes in non-cash working capital	15	**31.2**	(0.9)	**38.9**	3.4
Other		**13.2**	(0.6)	**7.6**	(12.0)
		(225.9)	(178.3)	**(677.0)**	(562.6)
Financing activities					
Issue of long term debt		**-**	255.0	**325.0**	255.0
Repayment of long term debt		**-**	(50.0)	**(100.0)**	(50.0)
Issue of equity preferred shares		**-**	-	**-**	115.0
Redemption of equity preferred shares to parent corporation		**-**	-	**-**	(126.5)
Issue of Class A and Class B shares		**-**	5.3	**-**	5.3
Dividends paid to Class A and Class B share owner		**(44.8)**	-	**(59.8)**	-
Changes in non-cash working capital	15	**(0.2)**	-	**(0.1)**	-
Other		**(3.3)**	(3.7)	**(4.1)**	(5.5)
		(48.3)	206.6	**161.0**	193.3
Cash position [1]					
Increase (decrease)		**(186.1)**	143.0	**(9.3)**	97.8
Beginning of period		**177.1**	(142.7)	**0.3**	(97.5)
End of period		**$ (9.0)**	$ 0.3	**$ (9.0)**	$ 0.3

[1] Cash position includes short term advance to parent corporation less current bank indebtedness and short term advances from parent and affiliate corporations.

CU Inc.
Consolidated Statement of Comprehensive Income
(Millions of Canadian Dollars)

	Note	Three Months Ended December 31 **2008**	2007	Year Ended December 31 **2008**	2007
		(Unaudited)			
Earnings attributable to Class A and Class B shares		**$58.2**	$53.4	**$200.3**	$177.3
Other comprehensive income, net of income taxes	19	**-**	(0.2)	**0.1**	(0.2)
Comprehensive income		**$58.2**	$53.2	**$200.4**	$177.1

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)).

Effective January 1, 2008, the Corporation adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations for capital disclosures which require disclosure of qualitative and quantitative information regarding the Corporation's objectives, policies and processes for managing capital (see Note 13).

Effective January 1, 2008, the Corporation adopted the CICA recommendations pertaining to disclosure and presentation of financial instruments which require disclosure of the classification of the Corporation's financial instruments (as described in the Financial Instruments section below) and additional qualitative and quantitative information regarding the nature and extent of risks arising from financial instruments to which the Corporation is exposed (see Note 18).

Effective January 1, 2008, the Corporation adopted the CICA recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value, and on the cost formulas that are used to assign costs to inventories. The recommendations also clarified that major spare parts are to be included in property, plant and equipment. As a result of adopting these recommendations, the Corporation reclassified $1.8 million of inventories to property, plant, and equipment related to major spare parts on January 1, 2008.

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 Battle River and Sheerness 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, asset retirement

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

obligations, employee future benefits and the fair value of financial instruments 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 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 transmission of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

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

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. Incentives and penalties associated with Alberta Power (2000)'s 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, is based on actual costs incurred.

Purchased Power

Purchased power expense for 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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.

Cash and Short Term Investments

Short term investments consist of bankers' acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short term investments with maturities generally of 90 days or less at purchase.

Inventories

Inventories are valued at the lower of cost or net realizable value. The cost of inventories is assigned using the weighted average cost method. Net realizable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

The cost of inventories is comprised of all costs of purchase, costs of conversion and other costs to bring the inventories to their present condition and location. The costs of purchase comprise the purchase price, import duties and non-recoverable taxes, and transport, handling and other costs directly attributable to the acquisition of finished goods, materials or services. The costs of conversion include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

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 Utilities Commission ("AUC") 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 AUC 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 discounted future cash flows.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt using the effective interest method. 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. The Corporation's long term debt is reduced by the respective financing charges.

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 discounted future cash flows.

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).

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Financial Instruments

The Corporation establishes the classification of financial instruments at their initial recognition. Financial assets are classified as held for trading, available for sale, held to maturity or loans and receivables. Financial liabilities are classified as held for trading or other liabilities.

Financial instruments classified as held for trading, other than derivative instruments that are effective hedging instruments, are measured at fair value with changes in fair value recognized in earnings. Derivatives that are designated as, and continue to be, effective cash flow hedging instruments have gains and losses in fair values recognized through other comprehensive income. Derivatives that are designated as fair value hedging instruments have gains and losses recognized in earnings.

Financial instruments classified as available for sale are measured at fair value using quoted prices in an active market. Changes in fair value are recognized in other comprehensive income until the item is derecognized or determined to be impaired, at which time the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. When actively quoted prices are not available, fair value is determined using other valuation techniques. If fair value cannot be reliably estimated, the item is carried at cost.

Financial instruments classified as held to maturity, loans and receivables or other liabilities are measured at fair value upon initial recognition but are subsequently measured at their amortized cost using the effective interest method.

Derivative Financial Instruments

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.

CICA recommendations require the recognition and measurement of derivative instruments embedded in host contracts that were issued, acquired or substantively modified on or after January 1, 2003. Derivative instruments embedded in host contracts that were issued, acquired or substantively modified prior to January 1, 2003 have not been identified and recognized in the consolidated financial statements as permitted by the recommendations.

The Corporation designates each derivative instrument as either a hedging instrument or a non-hedge derivative:

(a) A hedging instrument is designated as either:
   (i) a fair value hedge of a recognized asset or liability or,
   (ii) a cash flow hedge of either:
      - a specific firm commitment or anticipated transaction or,
      - the variable future cash flows arising from a recognized asset or liability.

   At inception of a hedge, the Corporation documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Corporation assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and measures the amount of any hedge ineffectiveness. The Corporation also assesses whether the hedging instrument is expected to be highly effective in the future.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

A hedging instrument is recorded on the consolidated balance sheet at fair value. Payments or receipts on a hedging instrument that is determined to be highly effective as a hedge are recognized concurrently with, and in the same financial category as, the hedged item. Subsequent changes in the fair value of a fair value hedge are recognized in earnings concurrently with the hedged item. For a cash flow hedge, the effective portion of changes in fair value is recognized in other comprehensive income and is subsequently transferred to earnings concurrently with the hedged item, whereas the portion of the changes in fair value that is not effective at offsetting the hedged exposure is recognized in earnings.

If a hedging instrument ceases to be highly effective as a hedge, is de-designated as a hedging instrument or is settled prior to maturity, then the Corporation ceases hedge accounting prospectively for that instrument; for a cash flow hedge, the gain or loss deferred to that date remains in accumulated other comprehensive income and is transferred to earnings concurrently with the hedged item. Subsequent changes in the fair value of that derivative instrument are recognized in earnings.

If the hedged item is sold, extinguished or matures prior to the termination of the related hedging instrument, or if it is probable that an anticipated transaction will not occur in the originally specified time frame, then the gain or loss deferred to that date for the related hedging instrument is immediately transferred from accumulated other comprehensive income to earnings.

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:
(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,
(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

The Corporation applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting implies the recognition of an asset on the day it is received by the Corporation and the recognition of the disposal of an asset on the day that it is delivered by the Corporation. Any gain or loss on disposal is also recognized on that day.

Transaction costs that are directly attributable to the acquisition or issue of financial assets or financial liabilities that are not held for trading are added to the fair value of such assets or liabilities at time of initial recognition.

Employee Future Benefits

The Corporation participates, together with Canadian Utilities Limited and its subsidiary corporations, in a registered 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 (“OPEB”) and non-registered group defined benefit pension plans. These plans are administered on a combined basis, and the Corporation accrues for its obligations under these 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.

In June 2008, the Corporation prospectively changed the method of apportioning the costs of OPEB plans to individual subsidiaries. Formerly, each subsidiary was apportioned a percentage of its payroll costs at a rate calculated for the plan as a whole. The revised method determines the accrued OPEB liabilities and costs on a company-by-company basis. Under the new method of allocation, the OPEB liability and non-current regulatory assets of the regulated operations, excluding Alberta Power (2000), increased by $10.4 million. Pursuant to an AUC 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. Consequently, there was no change to their earnings for the unaudited three months and year ended December 31, 2008. The difference between the amounts accrued and paid is deferred in non-current regulatory assets. The OPEB liability for Alberta Power (2000) decreased which resulted in an increase to earnings of $1.5 million, which was recorded in the fourth quarter of 2008.

For non-registered defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans.

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.

Future Accounting Changes

Effective for the Corporation beginning January 1, 2009, the CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. As permitted by Canadian GAAP, the Corporation will use standards issued by the Financial Accounting Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of Canadian GAAP. The adoption of these standards is not expected to have a material impact on the earnings of the Corporation. However, it is anticipated that the reserves for future removal and site restoration costs, which are currently netted against property, plant and equipment, will be reclassified to non-current liabilities, resulting in an increase to the Corporation's total assets and liabilities. The amount of such future removal and site restoration costs at December 31, 2008 was $461.2 million. The CICA has also issued new recommendations that will require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. The amount of unrecorded future income tax liabilities of the regulated operations at December 31, 2008 was $192.2 million. Upon adoption of the new standard, the Corporation expects to record an increase in future income tax liabilities and non-current regulatory assets of approximately $255 million. The additional amount reflects the future income tax effects of the settlement mechanism of the regulatory assets through customer rates that would occur in the future periods. These recommendations will be applied prospectively.

The CICA has issued new accounting recommendations for goodwill and intangible assets which establish standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets). These recommendations are effective for the Corporation beginning January 1, 2009. Goodwill and intangible assets that are not assets as defined by GAAP will be derecognized and charged to the equity of the Corporation at that date. The adoption of these recommendations is not expected to have a material impact on the earnings or assets of the Corporation.

The Canadian Accounting Standards Board confirmed in 2008 that the use of International Financial Reporting Standards ("IFRS") by publicly accountable enterprises will be required in 2011. The Corporation will need to begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to Canadian GAAP, but there could be significant differences in recognition, measurement and disclosures that will need to be addressed.

The Corporation has established a Steering Committee, a project team, and working groups to review the adoption of IFRS. The project team and working groups provide position papers and regular updates to management, the Steering Committee and the Audit Committee. Education sessions have been, and will continue to be, provided for employees, senior management and the Audit Committee to increase knowledge and awareness of IFRS and its impacts. An external expert advisor has been engaged. The Corporation is participating in various industry groups, including the Canadian Energy Pipeline Association, the Canadian Gas Association and the Canadian Electric Association.

The Corporation's IFRS Conversion Project consists of three phases: Assessment and Diagnostic; Design and Planning; and Implementation and Review. Position papers are being prepared on issue-specific accounting differences between Canadian GAAP and IFRS and the impact on financial reporting computer systems. These position papers are being reviewed with the Corporation's auditors. As a number of the IFRS standards are changing, the position papers will be updated to reflect any changes resulting from the final standards. The Corporation is also evaluating the potential impact of IFRS on financial covenants, business contracts and internal controls over financial reporting.

The Corporation reviews discussion papers, exposure drafts and standards released by the International Accounting Standards Board and the International Financial Reporting Interpretations Committee. The Corporation will continue to assess the impact of the proposed standards on its financial statements and disclosure as additional information becomes available. Financial impacts cannot be reasonably determined at this time.

Based on initial assessments the Corporation has identified that the following areas have the greatest potential impact to the Corporation's accounting: property, plant and equipment, joint arrangements, leases, rate regulated operations, deferred availability incentives and employee benefits. There will also be a significant amount of effort to comply with the IFRS' requirements for initial adoption of IFRS.

A more detailed analysis and evaluation of the financial impact of the issues identified in the assessment and diagnostic phases and the impact on and implementation of financial reporting computer systems will be completed in 2009.

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 AUC, which, effective January 1, 2008, succeeded the Alberta Energy and Utilities Board as regulator for the utilities industry. The AUC administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area.

The Battle River and Sheerness generating plants of Alberta Power (2000) were regulated by the AUC until December 31, 2000 but are now governed by legislatively mandated PPA's that were approved by the AUC. 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. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPA's expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant and be responsible for the decommissioning costs. For PPA's expiring after 2018, decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

The utilities are subject to a cost of service regulatory mechanism under which the AUC 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 AUC approved investment in property, plant and equipment, less accumulated depreciation, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. 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 AUC 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 and establishes the capital structure for each utility. On July 2, 2004, the AUC established a standardized approach for determining the rate of return on common equity for each utility regulated by the AUC. 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. The generic return on equity determined on an annual basis in accordance with the generic cost of capital decision applies 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 rate of return was 8.75% for 2008 (2007 – 8.51%) and has been set at a placeholder rate of 8.75% for 2009.

Under the cost of service methodology, the utilities seek approval for their revenue requirement either through submission of general rate applications to the AUC or a negotiated settlement process with interested parties. In the latter case, the AUC monitors the negotiated settlement process and any agreement that is reached is subject to AUC approval. The AUC 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 AUC renders a decision concerning these adjustments.

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

The regulatory assets and liabilities comprise the following:

	2008	2007
Regulatory assets – current:		
Deferred electricity costs	**$26.1**	$ 1.5
Current income tax savings associated with future income tax refund to customers	**1.9**	2.0
Deferred load balancing transactions	**2.9**	10.1
Deferral of unused vacation costs	**14.7**	13.9
Other regulatory assets [(1)]	**10.2**	2.5
	$55.8	$30.0
Regulatory assets – non-current:		
Regulatory pension asset (Note 17)	**$22.3**	$20.0
Regulatory other post employment benefits asset (Note 17)	**46.9**	32.3
Deferred electricity costs	**-**	17.4
Current income tax savings associated with future income tax refund to customers	**5.2**	7.0
Deferred hearing costs [(1)]	**8.4**	4.0
Reserves for injuries and damages	**-**	1.5
Other regulatory assets [(1)]	**4.8**	13.4
	$87.6	$95.6

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

	2008	2007
Regulatory liabilities – current:		
Deferred electricity cost recoveries	**$ 5.6**	$ -
Deferred load balancing transactions	**20.9**	5.9
Other regulatory liabilities [(1)]	**2.8**	-
	$29.3	$ 5.9
Regulatory liabilities – non-current:		
Deferred royalty credits	**$23.3**	$23.1
Deferred electricity cost recoveries	**-**	7.0
Reserves for injuries and damages	**3.3**	2.1
Other regulatory liabilities [(1)]	**10.5**	4.5
	$37.1	$36.7

[(1)] *Amortization of certain regulatory assets and liabilities, which are recorded in depreciation and amortization, amounted to $17.7 million (2007 – $7.7 million).*

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 utilities had recorded deferred pension assets of $23.0 million. The utilities have been earning an AUC approved rate of return on these assets through customer rates as the assets form part of the utilities' AUC approved rate base. In the absence of rate regulation, the utilities would not be able to earn a return on these assets. Consequently, revenues in 2008 would have been $1.2 million lower (2007 – $1.6 million lower). On October 11, 2006, the AUC issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the utilities to continue to earn an AUC approved rate of return on the unrecovered portion of these assets over the recovery period. In 2008, the utilities amortized $3.4 million (2007 – $2.6 million) of the deferred pension asset.

Pursuant to an AUC 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 asset. At December 31, 2008, the total amount of the regulatory other post employment benefits asset and the regulatory pension asset is $69.2 million (2007 – $52.3 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 plan cost in 2008 would have been $1.5 million higher (2007 – $2.0 million higher), and other post employment benefit plan cost in 2008 would have been $2.4 million higher (2007 – $2.9 million higher), in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

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 AUC 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 AUC 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 AUC 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 AUC and not adjusted for variances between the returns on forecast and actual rate base.

Variances between ATCO Electric's actual and forecast income tax provision may arise due to changes in enacted and substantively enacted tax rates. The amount included in customer rates is based on forecast tax rates. Revenues are adjusted for changes in enacted and substantively enacted tax rates, and the variances are deferred until approval from the AUC 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 customer rates approved by the AUC and not adjusted for variances between forecast and actual tax rates.

Consequently, revenues in 2008 would have been $8.6 million lower (2007 – $9.4 million lower) in the absence of rate regulation.

Current income tax savings associated with future income tax refund to customers

The AUC directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and to refund to customers the future income taxes of $34.4 million collected under the previously allowed tax methodology (see Note 3). This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in 2007, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $48.6 million , offset by a regulatory asset of $14.2 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities increased by $34.4 million as a result of this decision.

In December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers reducing the liability to customers to $32.5 million. In addition, the $16.1 million refund resulted in current income tax savings of $5.2 million, reducing the regulatory asset to $9.0 million. The total reduction in revenues and income taxes in 2007 was $39.6 million. ATCO Electric began refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008. ATCO Electric will realize the regulatory asset of $9.0 million over the same 5 year period with no effect on earnings as current income tax savings will be offset by this reduction in revenues.

Consequently, revenues for 2008 would have been $2.0 million higher (2007 – $9.0 million lower) in the absence of rate regulation. Assets of $1.9 million (2007 – $2.0 million) are included in current regulatory assets and $5.2 million (2007 – $7.0 million) are included in non-current regulatory assets in the balance sheet.

Deferred load balancing transactions

ATCO Pipelines has received AUC 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 AUC requesting recovery from or refund to customers of that particular deferral amount. On January 29, 2009, a decision was received that increases these amounts to $7.5 million for the North and $5.0 million for the South. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2008 would have been $22.2 million higher (2007 – $4.7 million higher) in the absence of rate regulation. Assets of $2.9 million (2007 - $10.1 million) are included in current regulatory assets, and liabilities of $20.9 million (2007 - $5.9 million) are included in current regulatory liabilities in the balance sheet.

Deferral of unused vacation costs

Revenue requirement includes a recovery from customers for vacation entitlement taken by employees during the year. A portion of the vacation entitlement is earned by employees and accrued as a liability in the prior year. GAAP requires that the vacation pay liability be expensed in the year accrued and not adjusted for amounts that will be recovered from customers. Consequently, expenses for 2008 would have been $0.8 million higher in the absence of rate regulation.

Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AUC 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 AUC. Hearing costs are deferred to the balance sheet and are amortized using AUC 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 AUC 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 2008 would have been $4.4 million higher (2007 – $3.0 million higher) in the absence of rate regulation.

Reserves for injuries and damages

The AUC 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 AUC to be amortized 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 AUC requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2008 would have been $1.6 million lower (2007 – $1.2 million higher) in the absence of rate regulation.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

For Alberta Power (2000), reserves for injuries and damages are recoverable under the terms of the PPA's on a straight line basis through 2008. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2008 would have been $1.0 million lower (2007 – $1.0 million lower) in the absence of rate regulation.

Deferred royalty credits

Under the terms of PPA's, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply are averaged over the term of each PPA. As such, royalty costs incurred are deferred and expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2008 would have been $0.2 million lower (2007 - $3.4 million lower) in the absence of rate regulation.

Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

a) ATCO Pipelines has received AUC approval to defer the variances between actual and AUC 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 has applied for approval to recover these deferral account balances in its general rate application which was filed with the AUC on October 1, 2007. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred.

   Consequently, revenues in 2008 would have been $0.6 million higher (2007 – $0.1 million higher) and expenses would have been $0.4 million lower (2007 – $0.2 million lower) in the absence of rate regulation. Assets of $0.3 million and $1.9 million (2007 – $2.5 million and $0.2 million) are included in current regulatory assets and non-current regulatory assets, respectively, and liabilities of $1.4 million and $0.1 million are included in current and non- current regulatory liabilities respectively (2007 – $0.9 million in non-current regulatory liabilities).

   ATCO Pipelines has received AUC 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 AUC, 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. ATCO Pipelines has applied for approval to recover this deferral account balance in its general rate application which was filed with the AUC on October 1, 2007. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2008 would have been $1.9 million lower (2007 – $2.2 million lower) in the absence of rate regulation. Assets of $7.8 million are included in current regulatory assets (2007 – $5.9 million included in non-current regulatory assets) in the balance sheet.

2. ACCOUNTING FOR RATE REGULATED OPERATIONS (continued)

c) ATCO Electric, ATCO Gas and ATCO Pipelines have provided interest free market differential loans to employees when relocating; however, ATCO Electric's revenue requirement includes a recovery from customers for imputed interest on these loans. The CICA recommendations regarding the measurement of financial assets require that these loans be measured at fair value, resulting in a reduction in their carrying amount. ATCO Electric defers the variances between the fair value and face value of the loans as a regulatory asset. GAAP requires that the variances be recorded as compensation expense upon issue of the loans, with subsequent accretion according to the effective interest method over their respective terms. Consequently, revenues for 2008 would have been \$0.1 million lower (2007 - \$1.1 million lower) in the absence of rate regulation. Assets of \$2.6 million (2007 - \$2.5 million) are included in non-current regulatory assets.

d) ATCO Gas, pursuant to an AUC decision, has received 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 Gas' North and South distribution pipeline systems. Should the deferral account for either the North or South exceed \$2.0 million over three successive months, ATCO Gas may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2008 would have been \$4.4 million higher (2007 - nil) in the absence of rate regulation. Liabilities of \$4.4 million are included in non-current regulatory liabilities in the balance sheet (2007 – nil).

e) ATCO Gas has received AUC approval to establish deferral accounts to mitigate the impact of temperature fluctuations on its revenues. Should the deferral account for either the North or the South exceed \$7.0 million at April 30th of any year, ATCO Gas may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral account. GAAP requires that the temperature impacted revenues be recognized in the period in which they are realized. Consequently, revenues in 2008 would have been \$2.7 million higher (2007 – nil) in the absence of rate regulation. Liabilities of \$2.7 million (2007 – nil) are included in non-current regulatory liabilities in the balance sheet.

Other items affected by rate regulation

The AUC 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 5).

3. REGULATORY MATTERS

In September 2007, ATCO Electric received a decision on its General Tariff Application for 2007 and 2008 which approved a return on common equity of 8.75% for 2008 and 8.51% for 2007. The effect of the decision on the earnings of ATCO Electric was not material.

The decision also directed ATCO Electric to change its income tax methodology for federal purposes. This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in 2007, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $48.6 million, offset by a regulatory asset of $14.2 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities increased by $34.4 million as a result of this decision.

In December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers reducing the liability to customers to $32.5 million. In addition, the $16.1 million refund resulted in current income tax savings of $5.2 million, reducing the regulatory asset to $9.0 million. The total reduction in revenues and income taxes in 2007 was $39.6 million. ATCO Electric began refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008. ATCO Electric will realize the regulatory asset of $9.0 million over the same 5 year period with no effect on earnings as current income tax savings will be offset by this reduction in revenues.

In July 2008, ATCO Electric filed a general tariff application with the AUC for 2009 and 2010 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Electric filed an application requesting interim refundable rates pending the AUC's decision on the application. In December 2008, ATCO Electric received a decision from the AUC approving interim refundable rate increases amounting to 50% of the requested increase for transmission operations and 25% of the requested increase for distribution operations. A hearing is scheduled for February 2009, with a decision expected by the third quarter in 2009.

In November 2007, ATCO Gas filed a general rate application with the AUC for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Gas also filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Gas received a decision from the AUC approving interim adjustable rate increases amounting to 50% of ATCO Gas' requested revenue increase.

In November 2008, ATCO Gas received a decision on its general rate application for 2008 and 2009 which was filed in November 2007. The decision established the amount of revenue requirement ATCO Gas can recover through distribution rates for natural gas distribution service to its customers for 2008 and 2009.

The effect of the decision on ATCO Gas' 2008 earnings was not materially different than the impact of the interim rates approved in December 2007. Other items of note stemming from the decision included: (i) the AUC direction to use the existing 38% common equity as a placeholder in its 2008 and 2009 revenue requirements until such time as the AUC issued further direction; (ii) the AUC direction to use the forecast 2008 and 2009 information and technology and customer care and billing costs submitted in the general rate application as placeholders pending the completion of the benchmarking process; (iii) to use the forecast 2008 and 2009 income tax amounts submitted in the general rate application until a further proceeding, currently scheduled to occur in the first quarter of 2009, is held to determine the proper regulatory treatment that can be accorded to the cost increases/reductions occasioned by income tax reassessments, deferral accounts for income tax purposes, and ATCO Gas' treatment of capital outlays as current expenditures for income tax purposes; and (iv) the AUC approval to establish deferral accounts deferring the impact of temperature fluctuations on ATCO Gas' revenues commencing January 1, 2008.

In May 2008, the Alberta Court of Appeal issued a decision in which it held that the AUC had erred in law or jurisdiction when it included ATCO Gas' Carbon storage facility in rate base for the purpose of generating revenues to offset customer rates. As a result of the Alberta Court of Appeal's decision, ATCO Gas requested and received approval from the AUC effective July 1, 2008 to suspend rate riders to customer rates on an interim basis. The suspension of the rate riders increased earnings for the unaudited three months and year ended December 31, 2008 by $1.0 million and $4.4 million, respectively. Additionally, ATCO Gas, on July 11, 2008, filed a compliance application with the AUC requesting removal of the Carbon facility from the utility rate base and revenue requirement effective April 1, 2005, consistent with the Alberta Court of Appeal decision.

In October 2007, ATCO Pipelines filed a general rate application for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with an increased rate base in Alberta. In November 2007, ATCO Pipelines filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Pipelines received a decision from the AUC approving interim adjustable rate increases amounting to 40% of ATCO Pipelines' requested revenue increase.

In November 2008, ATCO Pipelines filed an application requesting the AUC to approve a negotiated settlement with its customers of ATCO Pipelines' 2008 and 2009 revenue requirements in accordance with its general rate application. A decision on the application is expected in the first quarter of 2009. Also, in November 2008, the AUC approved ATCO Pipelines application for revised interim rates effective December 1, 2008 to collect 60% of its requested revenue increase.

In January 2009, ATCO Pipelines filed an application requesting AUC approval to commence negotiations with its customers to settle ATCO Pipelines' revenue requirements for each of the years 2010, 2011, and 2012.

In February 2008, the AUC initiated a generic proceeding to determine whether the standardized rate return methodology and the utility capital structures should be reviewed. A regulatory process has been established by the AUC with a hearing currently scheduled for May 19, 2009, to review the generic return on equity formula as well as to review the capital structure for each of the Alberta utilities. The AUC also indicated that any changes which result from this proceeding would be applied beginning in 2009. As ATCO Gas filed a general rate application for 2008 and 2009, a separate module within the generic proceeding will address 2008 cost of capital issues relating to the capital structure for ATCO Gas, as inclusion of these issues was removed from its 2008/2009 general rate application. The changes for 2008 and 2009 will not apply to ATCO Pipelines if its negotiated settlement for 2008 and 2009 revenue requirements is approved by the AUC.

A process continues with respect to the pricing of services provided by ATCO I-Tek to the utilities. A benchmarking report was received in January 2008 and filed with the AUC in February 2008, along with an application to adjust placeholders. In April 2008, an agreement with the customer group concerning the adjustment to placeholders was submitted to the AUC for approval. Should this agreement be approved by the AUC, it is not expected to have a material impact on consolidated earnings. The AUC has established a further process with a hearing scheduled for the second quarter of 2009 to review the issues related to the application and subsequent agreement with the customer group.

3. REGULATORY MATTERS (continued)

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

4. INTEREST AND OTHER INCOME

	2008	2007
Interest	**$ 9.0**	$ 6.6
Allowance for funds used by regulated operations	**17.9**	9.7
Gains (losses) on dispositions of property, plant and equipment	**(0.4)**	0.7
Other	**-**	1.0
	$26.5	$18.0

5. INCOME TAXES

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

	2008		2007	
Earnings before income taxes	**$244.3**	**%**	$200.4	%
Income taxes, at statutory rates	**$ 72.1**	**29.5**	$ 64.3	32.1
Part VI.1 tax (benefit)	**0.5**	**0.2**	(5.5)	(2.7)
Change in method of accounting for future income taxes in certain regulated operations	**-**	**-**	(34.4)	(17.2)
Unrecorded future income taxes relating to regulated operations	**(27.2)**	**(11.1)**	(4.9)	(2.5)
Change in future income taxes resulting from reduction in tax rates	**-**	**-**	0.9	0.4
Future income taxes recorded at less than current statutory rates	**0.3**	**0.1**	(1.0)	(0.5)
Tax reassessments	**(9.0)**	**(3.7)**	(8.8)	(4.4)
Other	**(4.0)**	**(1.6)**	(0.7)	(0.3)
	32.7	**13.4**	9.9	4.9
Current income taxes	**42.1**		36.8	
Future income tax recoveries	**$ (9.4)**		$ (26.9)	

5. INCOME TAXES (continued)

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

	2008	2007
Property, plant and equipment	**$ 43.8**	$ 38.7
Deferred assets and liabilities	**(24.8)**	(10.8)
Other	**-**	0.4
	19.0	28.3
Less: Amounts included in current future income taxes	**(5.6)**	2.1
	$ 24.6	$ 26.2

At December 31, 2008, unrecorded future income tax liabilities of the regulated operations amounted to $192.2 million. The liabilities include $1.6 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 2008, the Corporation received a favorable tax decision from the Canada Revenue Agency ("CRA") with respect to ATCO Electric and ATCO Pipelines to treat certain previously reported capital outlays as current expenditures for tax purposes. As a result, the Corporation recognized a reduction in current income tax expense and an increase in interest income in respect of prior taxation years which resulted in an increase in earnings of $3.3 million.

In addition, the Corporation recognized a reduction in income tax expense of $2.6 million as a result of a favorable Tax Court of Canada decision to treat previously reported capital outlays incurred with respect to certain transformer costs as current expenditures for tax purposes. This amount was included in a regulatory deferral account to be refunded to customers and, therefore, did not impact 2008 earnings.

On May 22, 2008, the Federal Court of Appeal issued a decision overturning previous CRA reassessments pertaining to the computation of resource allowances and corresponding capital cost allowances for mining assets related to the Corporation's coal-fired power generation business. On July 8, 2008, the CRA advised that it would not seek leave to appeal to the Supreme Court of Canada in respect of this matter. This appeal and subsequent court decision applies to the 1997 to 1998 taxation years and allows ATCO Electric and Alberta Power (2000), as successor to ATCO Electric in the coal-fired generating plants, to claim additional resource allowance and capital cost allowance. This reduced current income tax expense and decreased interest expense which resulted in an increase to earnings of $3.0 million.

In 2007, the federal government announced an amendment to tax legislation pertaining to Part VI.1 tax (the tax payable on preferred share dividends paid by corporations). Prior to this change, corporations that had Part VI.1 tax payable were entitled to an income tax deduction equal to 9/4ths of the Part VI.1 tax payable. Effective January 1, 2003, this deduction was increased to three times the amount of the Part VI.1 tax payable. The CRA has been assessing corporate tax returns based on this proposed change being in effect since January 1, 2003, resulting in a reduction of taxes paid to the Canadian government. In the second quarter of 2007, the Corporation recorded a one-time reduction to current income tax expense which resulted in increased earnings of $5.5 million relating to years prior to 2007. Funds generated by operations increased by $5.5 million, offset by a similar reduction in changes in non-cash working capital, leaving the Corporation's cash position unchanged.

5. INCOME TAXES (continued)

In the fourth quarter of 2007, ATCO Gas successfully appealed previous CRA reassessments which resulted in an $8.8 million decrease in income taxes and an increase in interest income, net of income taxes, of $0.7 million for an overall increase to earnings of $9.5 million. These ATCO Gas CRA reassessments applied to the 1999 to 2006 taxation years and allowed ATCO Gas to treat previously reported capital outlays as current expenditures for income tax purposes.

Income taxes paid amounted to $36.8 million (2007 – $45.1 million).

6. INVENTORIES

	2008	2007
Natural gas in storage	**$22.5**	$20.9
Raw materials and consumables	**54.5**	52.1
	$77.0	$73.0

For the unaudited three months ended December 31, 2008, the amount of inventories recognized as an expense was $19.0 million (2007 – $19.3 million). For the year ended December 31, 2008, the amount of inventories recognized as an expense was $72.1 million (2007 – $74.4 million). There have been no write-downs to net realizable value and there have been no reversals of previous write-downs to net realizable value.

No inventories are pledged as security for liabilities.

7. PROPERTY, PLANT AND EQUIPMENT

	2008			2007	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	3.6%	**$7,822.7**	**$2,765.3**	$7,026.1	$2,588.1
Power Generation	3.4%	**1,413.3**	**789.2**	1,387.5	741.8
		$9,236.0	**3,554.5**	$8,413.6	3,329.9
Property, plant and equipment less accumulated depreciation			**5,681.5**		5,083.7
Unamortized contributions by utility customers for extensions to plant			**798.8**		695.7
			$4,882.7		$4,388.0

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $461.2 million (2007 – $417.0 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $384.9 million (2007 – $110.2 million) and non-depreciable assets of $29.5 million (2007 – $34.5 million).

8. BANK INDEBTEDNESS, SHORT TERM ADVANCES FROM PARENT AND AFFILIATE CORPORATIONS AND LINES OF CREDIT

At December 31, 2008, bank indebtedness consists of \$15.0 million (2007 – \$6.9 million), which represents cheques outstanding in excess of cash in bank.

At December 31, 2008, there was no short term advance from an affiliate corporation (2007 – \$0.8 million consisting of a promissory note).

At December 31, 2008, the Corporation has the following lines of credit that enable it to obtain financing for general business purposes:

	2008			2007		
	Total	**Used**	**Available**	Total	Used	Available
Short term committed	**\$300.0**	**\$54.0**	**\$246.0**	\$300.0	\$10.0	\$290.0
Uncommitted	**29.1**	**1.0**	**28.1**	29.1	0.5	28.6
	\$329.1	**\$55.0**	**\$274.1**	\$329.1	\$10.5	\$318.6

All of the \$55.0 million used at December 31, 2008 represents outstanding letters of credit.

9. LONG TERM DEBT

	Effective Interest Rate	**2008**	2007
Long term debt			
Debentures – unsecured			
2000 6.97% due June 2008	7.062%	**\$ -**	\$ 100.0
1989 Series 10.20% due November 2009	10.331%	**125.0**	125.0
1990 Series 11.40% due August 2010	11.537%	**125.0**	125.0
2000 7.05% due June 2011	7.130%	**100.0**	100.0
2007 4.883% due November 2012	4.990%	**35.0**	35.0
2004 5.096% due November 2014	5.162%	**100.0**	100.0
2002 6.145% due November 2017	6.217%	**150.0**	150.0
2004 5.432% due January 2019	5.492%	**180.0**	180.0
1999 6.8% due August 2019	6.861%	**300.0**	300.0
1990 Second Series 11.77% due November 2020	11.903%	**100.0**	100.0
2006 4.801% due November 2021	4.854%	**160.0**	160.0
1991 Series 9.92% due April 2022	10.063%	**125.0**	125.0
1992 Series 9.40% due May 2023	9.511%	**100.0**	100.0
2008 5.563% due May 2028	5.614%	**125.0**	-
2004 5.896% due November 2034	5.939%	**200.0**	200.0
2005 5.183% due November 2035	5.226%	**185.0**	185.0
2006 5.032% due November 2036	5.072%	**160.0**	160.0
2007 5.556% due October 2037	5.598%	**220.0**	220.0
2008 5.580% due May 2038	5.622%	**200.0**	-

9. LONG TERM DEBT (continued)

	Effective Interest Rate	**2008**	2007
***Long term debt** (continued)*			
Other long term obligation, due June 2010, unsecured	4.750%	**4.5**	4.5
Less: Deferred financing charges		**(14.3)**	(13.1)
		2,680.2	2,456.4
Long term debt to parent corporation			
Non-interest bearing promissory note, unsecured		**3.0**	3.0
		$2,683.2	$2,459.4

Contractual maturities of debt

The undiscounted contractual maturities of long term debt and non-recourse long term debt are as follows:

	Principal	Interest
2009	$ 125.0	$ 181.5
2010	129.5	168.7
2011	100.0	150.8
2012	35.0	147.2
2013	-	145.5
2014 and thereafter	2,305.0	1,819.0
	$2,694.5	$2,612.7

The amount due in 2009 is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest expense is as follows:

	2008	2007
Long term debt	**$178.4**	$164.3
Bank indebtedness	**1.9**	0.4
Amortization of deferred financing charges	**1.2**	1.1
	$181.5	$165.8

Interest paid amounted to $178.7 million (2007 – $162.3 million).

10. DEFERRED CREDITS

	2008	2007
Deferred availability incentives	**$ 61.3**	$ 41.8
Accrued other post employment benefits liability (Note 17)	**47.2**	32.6
Asset retirement obligations	**44.4**	42.1
Liability to customers for refund of future income taxes (Note 3)	**19.2**	25.8
Accrued pension liability (Note 17)	**10.6**	5.0
Other	**16.9**	19.4
	$199.6	$166.7

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $12.6 million (2007 – $11.8 million).

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

Asset retirement obligations

Changes in asset retirement obligations are summarized below:

	2008	2007
Obligations at beginning of year	**$42.1**	$39.9
Accretion expense	**2.3**	2.2
Obligations at end of year	**$44.4**	$42.1

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 2009 and 2026. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.8%.

11. EQUITY PREFERRED SHARES AND EQUITY PREFERRED SHARES TO PARENT CORPORATION

Equity preferred shares

Authorized and issued

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

Issued:

	Stated Value	Redemption Dates	**2008** Shares	**2008** Amount	2007 Shares	2007 Amount
	(dollars)					
Cumulative Redeemable Preferred Shares						
4.60% Series 1	$25.00	See below	**4,600,000**	**$115.0**	4,600,000	$115.0

On April 18, 2007, CU Inc. issued $115.0 million Cumulative Redeemable Preferred Shares Series 1 at a price of $25.00 per share for cash. The dividend rate has been fixed at 4.60%. The net proceeds of the issue were used in part to redeem the $91.8 million of outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S of ATCO Electric and ATCO Gas and Pipelines on May 18, 2007. In addition, on May 18, 2007, Alberta Power (2000) redeemed the $34.7 million of outstanding Series Q, R and S Preferred Shares. All of the Series Q, R and S Preferred Shares were held by Canadian Utilities Limited, CU Inc.'s parent corporation.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $67.2 million (2007 – $94.7 million).

Redemption privileges

The Series 1 preferred shares are redeemable at the option of the Corporation commencing on June 1, 2012, at the stated value plus a 4% premium per share for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding twelve month period until June 1, 2016.

Equity preferred shares to parent corporation

Authorized and issued

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

Issued:

	Stated Value	Redemption Dates	**2008** Shares	**2008** Amount	2007 Shares	2007 Amount
	(dollars)					
Perpetual Cumulative Second Preferred Shares						
4.35% Series U	$25.00	December 2, 2011	**800,000**	**$ 20.0**	800,000	$ 20.0
4.70% Series V	$25.00	October 3, 2012	**4,400,000**	**110.0**	4,400,000	110.0
				$130.0		$130.0

11. EQUITY PREFERRED SHARES AND EQUITY PREFERRED SHARES TO PARENT CORPORATION (continued)

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.

On October 3, 2007, the dividend rate on the Series V preferred shares was reset from 5.25% to 4.70%.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $122.4 million (2007 – $127.8 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.

12. 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:	**3,286,124**	**$256.0**	**2,014,076**	**$156.9**	**5,300,200**	**$412.9**

13. CAPITAL DISCLOSURES

The Corporation's objectives when managing capital are:

1. to safeguard the ability to continue as a going concern, so that it can continue to provide returns to its share owner and benefits for other stakeholders;
2. to maintain an appropriate credit rating in order to provide efficient and cost effective access to funds required for operations and growth; and
3. to remain within the capital structure approved by the AUC.

The Corporation includes share owner's equity, equity preferred shares, equity preferred shares to parent corporation, and long term debt in its determination of capitalization. In managing its capital, the Corporation considers the impact of the AUC's decisions with respect to the Corporation's subsidiaries as well as changes in economic conditions and risks impacting the core assets and operations. In maintaining or adjusting its capital structure, the Corporation may adjust the amount of dividends paid to the share owner, issue or purchase Class A and Class B shares and issue or redeem preferred shares and long term debt.

13. CAPITAL DISCLOSURES (continued)

The Corporation's utility operations are regulated primarily by the AUC, which, through the generic cost of capital decision issued in 2004, established the capital structure for each utility. The utility operations are, therefore, capitalized consistent with the generic cost of capital decision. The capitalization involves the use of long term debt and preferred share financings; the AUC approved the continued use of the latter in a decision issued in 2006.

While the Corporation's utility operations are capitalized consistent with the AUC decisions, the Corporation itself is not restricted in its capital structure. However, management chooses to maintain the capital structure of the Corporation according to the structure approved by the AUC for its utility operations.

Decisions on the level and type of financing are based on assessments by management in line with the Corporation's objectives. In determining the type of financing to be undertaken by a given operation, the Corporation has a goal of managing the financial risk to the Corporation as a whole.

Capital is monitored through an equity capitalization measure which is calculated as total equity divided by total capitalization. Total equity is comprised of Class A and Class B shares, retained earnings, accumulated other comprehensive income, equity preferred shares and equity preferred shares to parent corporation. Total capitalization is comprised of long term debt and total equity. The Corporation's strategy, which is unchanged from 2007, is to maintain the equity capitalization allowed by the regulator. The Corporation looks to maintain an equity capitalization in the range of 40% to 50%.

Other measures that are taken into consideration are interest coverage and interest and preferred dividend coverage. Interest coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by total interest expense. Interest and preferred dividend coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by interest expense and dividends on equity preferred shares (grossed up to pre-tax equivalents). The Corporation looks to maintain interest coverage of at least 1.8 and interest and preferred dividend coverage of at least 1.5; these objectives are unchanged from 2007.

Equity capitalization, interest coverage and interest and preferred dividend coverage do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

The Corporation's key measures of capital structure are as follows:

	2008	2007
Class A and Class B shares	**$ 412.9**	$ 412.9
Retained earnings	**1,403.2**	1,262.7
Accumulated other comprehensive income	**-**	(0.1)
Equity preferred shares	**115.0**	115.0
Equity preferred shares to parent corporation	**130.0**	130.0
Total equity	**2,061.1**	1,920.5
Long term debt	**2,683.2**	2,459.4
Total capitalization	**$4,744.3**	$4,379.9
Equity capitalization	**43%**	44%

13. CAPITAL DISCLOSURES (continued)

The equity capitalization is consistent with the Corporation's objectives. Total equity increased primarily due to higher earnings of the Corporation reflected in increased retained earnings. Total debt increased primarily due to financings for utility capital expenditures.

	2008	2007
Interest coverage [(1)]	**2.3**	2.2
Interest and preferred dividend coverage [(1)]	**2.1**	2.0

(1) The coverage ratios for 2007 were negatively impacted by the AUC decision that directed ATCO Electric to refund future income taxes to customers. The total reduction in revenues and income taxes recorded in 2007 was $39.6 million. If the reduction in revenues had not occurred, interest coverage would have been 2.4 and interest and preferred dividend coverage would have been 2.2.

For the year ended December 31, 2008, the Corporation was in compliance with externally imposed requirements on its capital (including debt covenants). The Corporation has a number of regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received, the outcome of which could affect the capital structure of the Corporation.

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 income amounted to $0.5 million (2007 – $0.1 million expense).

15. CHANGES IN NON-CASH WORKING CAPITAL

	2008	2007
Operating activities, changes related to:		
Accounts receivable	**$ (6.0)**	$(16.9)
Accounts receivable from parent and affiliate corporations	**(7.4)**	5.6
Inventories	**(3.9)**	0.2
Regulatory assets	**(12.4)**	(14.7)
Prepaid expenses	**2.0**	-
Accounts payable and accrued liabilities	**16.5**	35.0
Accounts payable to parent and affiliate corporations	**(1.1)**	7.5
Income taxes payable	**1.9**	(7.9)
Regulatory liabilities	**11.9**	5.5
	$ 1.5	$ 14.3
Investing activities, changes related to:		
Inventories	**$ (1.7)**	$ (2.9)
Prepaid expenses	**1.6**	(1.1)
Accounts payable and accrued liabilities	**39.0**	7.4
	$ 38.9	$ 3.4
Financing activities, changes related to:		
Accounts receivable	**$ (0.1)**	$ -

16. RELATED PARTY TRANSACTIONS

Entity	Relationship	Transaction	Recorded As	2008	2007
Canadian Utilities Limited	Parent	Sale of electricity and natural gas, lease of land, rent and office services	Revenues	**$ 0.4**	$ 0.7
		Rent and aircraft usage	Selling and administrative	**7.9**	7.5
		Purchase of equipment and leasehold improvements	Property, plant and equipment	**1.9**	1.5
ATCO Ltd. and ATCO Investments Ltd.	Affiliates	Corporate signature rights and rent	Selling and administrative	**3.3**	**3.3**
ASHCOR Technologies Ltd., ATCO Frontec Corp., ATCO I-Tek Inc. , ATCO Midstream Ltd., ATCO Power Ltd., and ATCO Energy Solutions Ltd.	Affiliates	Natural gas storage, transportation and other gas services, sale of ash, rent and office services, payroll and accounting services	Revenues	**29.0**	**28.5**
		Purchase and storage of natural gas	Natural gas supply	**4.1**	**2.9**
		Purchase of natural gas	Operation and maintenance	**10.2**	**8.5**
		Purchase of natural gas	Regulatory assets	**(19.2)**	**(3.8)**
		Computer operations and systems development, call centre and customer billing services, property management and security services	Operation and maintenance, selling and administrative	**80.5**	**79.0**
		North Warning System joint venture earnings	Other income	**0.3**	**0.2**
		Purchase of equipment, capitalized costs and capitalized software	Property, plant and equipment	**41.2**	**31.8**

The Corporation incurred advertising and promotion expenses from an entity related through common control totaling $0.3 million (2007 – $0.3 million).

At December 31, 2008, accounts receivable due from related parties amounted to $10.2 million (2007 – $2.9 million) and accounts payable due to related parties amounted to $34.5 million (2007 – $35.6 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 registered defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases. The Corporation, together with Canadian Utilities Limited and its subsidiary corporations, also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

Contributions to the Group Plan, which is accounted for as a defined contribution pension plan, are expensed as paid. Other post employment benefit and non-registered 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 non-registered defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans. Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and non-registered defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred in regulatory assets.

In June 2008, the Corporation prospectively changed the method of apportioning the costs of OPEB plans to individual subsidiaries. Formerly, each subsidiary was apportioned a percentage of its payroll costs at a rate calculated for the plan as a whole. The revised method determines the accrued OPEB liabilities and costs on a company-by-company basis. Under the new method of allocation, the OPEB liability and non-current regulatory assets of the regulated operations, excluding Alberta Power (2000), increased by $10.4 million. Pursuant to an AUC 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. Consequently, there was no change to their earnings for the unaudited three months and year ended December 31, 2008. The difference between the amounts accrued and paid is deferred in non-current regulatory assets. The OPEB liability for Alberta Power (2000) decreased which resulted in an increase to earnings of $1.5 million, which was recorded in the fourth quarter of 2008.

17. EMPLOYEE FUTURE BENEFITS (continued)

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

	2008		2007	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost:				
Total cost	**$ 10.3**	**$ 4.2**	$ 10.0	$ 7.0
Less: Capitalized	**2.0**	**2.5**	2.1	2.5
Less: Regulatory deferral [(1)]	**1.5**	**2.4**	2.0	2.9
Net cost (income) recognized [(2)]	**$ 6.8**	**$ (0.7)**	$ 5.9	$ 1.6
Accrued benefit plan assets and liabilities:				
Accrued asset (liability) at beginning of year	**$ (5.0)**	**$(32.6)**	$ 0.7	$(27.9)
Adjustment to beginning liability	**-**	**(10.4)**	-	-
Total cost	**(10.3)**	**(4.2)**	(10.0)	(7.0)
Benefit payments	**4.7**	**-**	4.3	2.3
Accrued liability at end of year (Note 10)	**$(10.6)**	**$(47.2)**	$ (5.0)	$(32.6)
Regulatory benefit plan assets [(1)] (Note 2):				
Regulatory asset at beginning of year	**$ 20.0**	**$ 32.3**	$ 17.0	$ 27.6
Adjustment to beginning liability	**-**	**10.4**	-	-
Regulatory cost deferral	**1.5**	**2.4**	2.0	2.9
Regulatory cost capitalized	**0.8**	**1.8**	1.0	1.8
Regulatory asset at end of year	**$ 22.3**	**$ 46.9**	$ 20.0	$ 32.3

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

(2) *Net cost recognized for pension benefit plans in 2008 includes the amortization of $3.4 million (2007 – $2.6 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 AUC approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).*

In the unaudited three months ended December 31, 2008, net cost of $2.3 million (2007 – $1.2 million) was recognized for pension benefit plans and net income of $1.0 million (2007 – net cost of $0.2 million) was recognized for other post employment benefit plans.

17. EMPLOYEE FUTURE BENEFITS (continued)

Weighted average assumptions

	2008		2007	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost:				
Liability discount rate for the year	**5.5%**	**5.5%**	5.1%	5.1%
Average compensation increase for the year	**(1)**	**-**	(1)	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**7.0%**	**7.0%**	5.5%	5.5%
Long term inflation rate	**2.5%**	**(2)**	2.5%	(2)

(1) *The assumed average compensation increases are 4.0% for 5 years (2008-2012) and 3.5% thereafter.*

(2) *The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 7.2% for 2008 grading down over 5 years to 4.5% (2007 – 7.8% for 2007 grading down over 6 years to 4.5%), and, for other medical and dental costs, 4.0% for 2008 and thereafter (2007 – 4.0% for 2007 and thereafter).*

Funding

Employees are required to contribute a percentage of their salary to the registered 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, 2006, the Corporation is continuing a contribution holiday that began on April 1, 1996 for all but one of the registered pension plans; commencing in 2007, the Corporation is required to make annual contributions of approximately $0.7 million to cover the unfunded liability of that plan. The next actuarial valuation for funding purposes is required as of December 31, 2009. The Government of Alberta has issued a white paper which, if it becomes law, would require an actuarial valuation to be filed as at December 31, 2008 for those plans that wish to continue their contribution holidays in 2009. Depending on the outcome of the full actuarial valuation, current service contributions may be required to resume in 2009.

18. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Corporation's Board of Directors ("Board") is responsible for understanding the principal risks of the business in which the Corporation is engaged, achieving a proper balance between risks incurred and the potential return to the share owner, and confirming that there are systems in place that effectively monitor and manage those risks with a view to the long-term viability of the Corporation. The Board has established a Risk Review Committee, which reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Corporation's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

18. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

The Corporation is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. In conducting its business, the Corporation may use 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 currency exchange rate risk

Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency. The Corporation has no outstanding foreign currency forward contracts at December 31, 2008 (2007 – purchases of £0.7 million to fix the exchange rate on certain service contracts denominated in U.K. pounds sterling).

Credit risk

For cash and short term investments, short term advances to parent corporation and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Cash and short term investments credit risk is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short term instruments.

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.

The maximum exposure to credit risk is the carrying value of loans and receivables on the balance sheet. The Corporation does not have a concentration of credit risk with any counterparties. Substantially all of the loans and receivables arise from the Corporation's operations in Alberta.

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.

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. At December 31, 2008, the provision for impairment of credit losses was $0.3 million; this provision is unchanged from December 31, 2007.

At December 31, 2008, the aging analysis of trade receivables that are past due but not impaired is as follows:

	2008
30 to 90 days	**$2.0**
Greater than 90 days	**1.0**
	$3.0

No other impairments have been identified within accounts receivable.

18. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities. Funds generated by operations provide a substantial portion of the Corporation's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used under available credit lines to provide flexibility in the timing and amounts of long term financing. The Corporation has a policy not to invest any of its cash balances in asset backed securities; consequently, the recent turmoil in the asset-backed commercial paper market has had no impact on the Corporation.

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

	2009	2010	2011	2012	2013	2014 and thereafter
Accounts payable and accrued liabilities	$321.7	$ -	$ -	$ -	$ -	$ -
Operating leases [1]	10.9	10.4	8.9	5.9	5.6	26.9
Purchase obligations:						
Coal purchase contracts [2]	50.2	51.2	52.8	89.1	54.9	308.7
Natural gas purchase contracts	0.4	0.4	0.4	0.4	0.4	-
Operating and maintenance agreements [3]	3.3	1.8	1.8	-	-	-
Capital expenditures [4]	110.7	-	-	-	-	-
Other	0.3	0.2	0.2	0.1	-	-
	$497.5	$64.0	$64.1	$95.5	$60.9	$335.6

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

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

(3) Alberta Power (2000) has long term service agreements with suppliers to provide operating and maintenance services at certain of their generating plants.

(4) Various contracts to purchase goods and services with respect to capital expenditures.

Fair value of non-derivative financial instruments

The carrying values and fair values of the Corporation's non-derivative financial instruments are as follows:

	2008		2007	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Financial Assets				
Loans and Receivables:				
Short term advance to parent corporation [1]	**$ 6.0**	**$ 6.0**	$ 8.0	$ 8.0
Accounts receivable [1]	**247.5**	**247.5**	241.3	241.3
Accounts receivable from parent and affiliate corporations [1]	**10.2**	**10.2**	2.9	2.9
Financial Liabilities				
Held For Trading:				
Bank indebtedness [1]	**15.0**	**15.0**	6.9	6.9
Other Liabilities:				
Short term advances from parent and affiliate corporations [2]	**-**	**-**	0.8	0.8
Accounts payable and accrued liabilities [2]	**321.7**	**321.7**	219.0	219.0
Accounts payable to parent and affiliate corporations [2]	**34.5**	**34.5**	35.6	35.6
Liability to customers for refund of future income taxes (Note 10) [3]	**19.2**	**19.2**	25.8	25.8
Long term debt [3]	**2,680.2**	**2,690.3**	2,456.4	2,754.6
Long term debt to parent corporation [4]	**3.0**	**3.0**	3.0	3.0

(1) *Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments and negligible credit losses.*

(2) *Recorded at cost. Fair value approximates the carrying amounts due to the short term nature of the financial instruments.*

(3) *Recorded at amortized cost. Fair values are determined using quoted market prices for the same or similar issues. 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.*

(4) *Recorded at carrying amount. The long term debt to parent corporation is repayable on demand; therefore, the fair value is equal to carrying amount.*

18. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS (continued)

Fair value of derivative financial instruments

The fair values of the Corporation's derivative financial instruments are as follows:

	2008			2007		
	Notional Principal[(1)]	**Fair Value Receivable (Payable)[(2)]**	**Maturity**	Notional Principal[(1)]	Fair Value Receivable (Payable)[(2)]	Maturity
Held For Trading:						
Foreign currency forward contracts	**Nil**	**Nil**	**N/A**	$1.4	(0.1)	2008

(1) *The notional principal is not recorded in the consolidated financial statements as it does not represent amounts that are exchanged by the counterparties.*

(2) *Fair values for the foreign currency forward contracts have been estimated using period-end market rates. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.*

19. OTHER COMPREHENSIVE INCOME

Other comprehensive income ("OCI") of the Corporation is comprised of two components: the unrealized gains and losses on effective cash flow hedging instruments and the unrealized gains and losses on financial assets that are available for sale.

Changes in the components of accumulated OCI are summarized below:

	2008	2007
Accumulated OCI at beginning of period:		
Cash flow hedge losses [(1)]	**$(0.1)**	$ -
Adjustment to accumulated OCI at beginning of period due to change in method of accounting for:		
Financial assets available for sale [(1)]	-	0.1
OCI for the period:		
Changes in fair values of cash flow hedges [(1)]	-	(0.1)
Transfer of gain on financial assets available for sale to earnings [(1)]	-	(0.1)
Transfers of cash flow hedge losses to earnings [(1)]	**0.1**	-
	0.1	(0.2)
Accumulated OCI at end of period:		
Cash flow hedge losses [(1)]	-	$(0.1)

(1) *Net of income taxes of nil.*

20. CONTINGENCIES

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 AUC.

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

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

In 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. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

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 AUC 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 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's payment and indemnity obligations to DEML contemplated under the transaction agreements.

21. 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 transmission and distribution of water by CU Water, the regulated transmission of natural gas by ATCO Pipelines, and the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical.

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

Segmented results – Three months ended December 31

2008 2007	Utilities	Power Generation	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)					
Revenues – external	**\$330.3** \$312.4	**\$83.2** \$81.8	**\$ -** \$ -	**\$ -** \$ -	**\$413.5** \$394.2
Revenues – intersegment [1]	**0.1** 0.1	**-** -	**-** -	**(0.1)** (0.1)	**-** -
Revenues	**\$330.4** \$312.5	**\$83.2** \$81.8	\$ **-** \$ -	**\$(0.1)** \$(0.1)	**\$413.5** \$394.2
Earnings attributable to Class A and Class B shares	**\$ 45.3** \$ 47.3	**\$12.7** \$ 6.0	**\$ 0.2** \$ 0.1	**\$ -** \$ -	**\$ 58.2** \$ 53.4

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

21. SEGMENTED INFORMATION (continued)

Segmented results – Year ended December 31

2008 2007	Utilities	Power Generation	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,260.8** $1,114.4	**$312.6** $299.8	**$ -** $ -	**$ -** $ -	**$1,573.4** $1,414.2
Revenues – intersegment [(1)]	**0.1** 0.2	**-** -	**-** -	**(0.1)** (0.2)	**-** -
Revenues	**1,260.9** 1,114.6	**312.6** 299.8	**-** -	**(0.1)** (0.2)	**1,573.4** 1,414.2
Operating expenses	**718.7** 641.1	**156.4** 153.8	**-** -	**(0.1)** (0.1)	**875.0** 794.8
Depreciation and amortization	**248.3** 223.6	**50.8** 47.6	**-** -	**-** -	**299.1** 271.2
Interest expense	**157.5** 140.3	**24.2** 25.3	**181.7** 165.0	**(181.9)** (164.8)	**181.5** 165.8
Interest and other income	**(25.5)** (16.7)	**(0.8)** (0.9)	**(182.1)** (165.1)	**181.9** 164.7	**(26.5)** (18.0)
Earnings before income taxes	**161.9** 126.3	**82.0** 74.0	**0.4** 0.1	**-** -	**244.3** 200.4
Income taxes	**3.4** (22.6)	**29.2** 32.5	**0.1** -	**-** -	**32.7** 9.9
	158.5 148.9	**52.8** 41.5	**0.3** 0.1	**-** -	**211.6** 190.5
Dividends on equity preferred shares	**5.3** 3.7	**-** -	**-** -	**-** -	**5.3** 3.7
Dividends on equity preferred shares to parent corporation	**4.6** 7.0	**1.4** 2.5	**-** -	**-** -	**6.0** 9.5
Earnings attributable to Class A and Class B shares	**$ 148.6** $ 138.2	**$ 51.4** $ 39.0	**$ 0.3** $ 0.1	**$ -** $ -	**$ 200.3** $ 177.3
Total assets	**$4,696.3** $4,146.7	**$709.7** $733.1	**$ 0.1** $ 0.1	**$ -** **$** -	**$5,406.1** $4,879.9
Purchase of property, plant and equipment	**$ 852.6** $ 588.8	**$ 25.8** $ 26.6	**$ -** $ -	**$ -** $ -	**$ 878.4** $ 615.4

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