



CONSOLIDATED FINANCIAL STATEMENTS

**FOR THE YEAR ENDED
DECEMBER 31, 2004**

February 11, 2005

Auditors' Report

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

We have audited the consolidated balance sheets of **CU Inc.** as at December 31, 2004 and 2003 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

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

| | Note | Three Months Ended December 31 | | Year Ended December 31 | |
|---|------|-----------------------------------|----------------------------|---------------------------|----------------------------|
| | | 2004 | 2003 | 2004 | 2003 |
| | | | (Restated, Notes 1, 11) | | (Restated, Notes 1, 11) |
| | | <i>(Unaudited)</i> | | | |
| Revenues | 3 | \$ 371.7 | \$ 728.1 | \$2,078.7 | \$2,846.2 |
| Costs and expenses | | | | | |
| Natural gas supply | 3 | 23.1 | 340.6 | 726.1 | 1,361.8 |
| Purchased power | 3 | 15.4 | 46.8 | 95.8 | 209.8 |
| Operation and maintenance | | 78.0 | 80.9 | 305.8 | 306.1 |
| Selling and administrative | | 44.7 | 61.7 | 190.2 | 208.9 |
| Depreciation and amortization | | 63.5 | 56.5 | 222.4 | 207.1 |
| Interest | 10 | 37.1 | 35.7 | 144.9 | 143.8 |
| Franchise fees | | 37.5 | 30.5 | 133.4 | 122.6 |
| | | 299.3 | 652.7 | 1,818.6 | 2,560.1 |
| | | 72.4 | 75.4 | 260.1 | 286.1 |
| Gain on transfer of retail energy supply businesses | 3 | - | - | 63.3 | - |
| Interest and other income | 4 | 4.4 | 5.9 | 9.4 | 10.0 |
| Earnings before income taxes | | 76.8 | 81.3 | 332.8 | 296.1 |
| Income taxes | 5 | 19.8 | 23.4 | 97.2 | 107.3 |
| | | 57.0 | 57.9 | 235.6 | 188.8 |
| Dividends on equity preferred shares to parent corporation | | 3.5 | 3.5 | 14.0 | 14.0 |
| Earnings attributable to Class A and Class B shares | 3 | 53.5 | 54.4 | 221.6 | 174.8 |
| Retained earnings at beginning of period as restated | 6 | 1,070.7 | 996.5 | 1,003.4 | 925.2 |
| | | 1,124.2 | 1,050.9 | 1,225.0 | 1,100.0 |
| Dividends on Class A and Class B shares | | 87.9 | 47.5 | 188.7 | 96.6 |
| Retained earnings at end of period | | \$1,036.3 | \$1,003.4 | \$1,036.3 | \$1,003.4 |

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

| | | December 31 | |
|--|------|------------------|----------------------------|
| | Note | 2004 | 2003 |
| | | | (Restated, Notes 1, 11) |
| ASSETS | | | |
| Current assets | | | |
| Cash and short term investments | | \$ 64.0 | \$ 42.8 |
| Accounts receivable | | 230.3 | 429.3 |
| Accounts receivable from parent and affiliate corporations | | 12.2 | 4.0 |
| Inventories | | 157.7 | 155.9 |
| Income taxes recoverable | | - | 21.4 |
| Future income taxes | 5 | 0.3 | - |
| Deferred natural gas costs | | - | 27.2 |
| Prepaid expenses | | 12.9 | 13.0 |
| | | 477.4 | 693.6 |
| Property, plant and equipment | 7 | 3,644.6 | 3,438.5 |
| Other assets | 8 | 63.0 | 73.3 |
| | | \$4,185.0 | \$4,205.4 |
| LIABILITIES AND SHARE OWNER'S EQUITY | | | |
| Current liabilities | | | |
| Short term advances from parent and affiliate corporations | 9 | \$ 9.6 | \$ 285.0 |
| Accounts payable and accrued liabilities | | 164.4 | 284.1 |
| Accounts payable to parent and affiliate corporations | | 23.3 | 80.7 |
| Income taxes payable | | 24.6 | - |
| Future income taxes | 5 | - | 11.5 |
| Deferred natural gas cost recoveries | | 0.9 | - |
| Deferred electricity cost recoveries | | 11.7 | 1.0 |
| | | 234.5 | 662.3 |
| Future income taxes | 5 | 64.8 | 80.0 |
| Deferred credits | 11 | 122.8 | 113.1 |
| Long term debt | 10 | 2,062.5 | 1,682.5 |
| Equity preferred shares to parent corporation | 12 | 256.5 | 256.5 |
| Class A and Class B share owner's equity | | | |
| Class A and Class B shares | 13 | 407.6 | 407.6 |
| Retained earnings | | 1,036.3 | 1,003.4 |
| | | 1,443.9 | 1,411.0 |
| | | \$4,185.0 | \$4,205.4 |



K.M. WATSON
DIRECTOR



B.K. FRENCH
DIRECTOR

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

| | Note | Three Months Ended December 31 | | Year Ended December 31 | |
|---|------|-----------------------------------|----------------------------|---------------------------|----------------------------|
| | | 2004 | 2003 | 2004 | 2003 |
| | | | (Restated, Notes 1, 11) | | (Restated, Notes 1, 11) |
| | | | <i>(Unaudited)</i> | | |
| Operating activities | | | | | |
| Earnings attributable to Class A and Class B shares | | \$ 53.5 | \$ 54.4 | \$ 221.6 | \$ 174.8 |
| Adjustments for: | | | | | |
| Depreciation and amortization | | 63.5 | 56.5 | 222.4 | 207.1 |
| Future income taxes | | (14.7) | 2.3 | (14.6) | 3.4 |
| Gain on transfer of retail energy supply businesses | | | | | |
| - net of income taxes | 3 | - | - | (55.1) | - |
| Deferred availability incentives | | 8.1 | (1.5) | 2.8 | (1.7) |
| Other | | 1.5 | 1.0 | 5.5 | 4.9 |
| Cash flow from operations | | 111.9 | 112.7 | 382.6 | 388.5 |
| Changes in non-cash working capital | 15 | (14.9) | (75.5) | 119.9 | (61.5) |
| | | 97.0 | 37.2 | 502.5 | 327.0 |
| Investing activities | | | | | |
| Purchase of property, plant and equipment | | (136.1) | (140.8) | (458.3) | (383.3) |
| Proceeds on transfer of retail energy supply businesses | | | | | |
| - net of income taxes | 3 | - | - | 22.5 | - |
| Proceeds (costs) on disposal of property, plant and equipment | | (1.4) | 6.4 | (5.0) | 11.8 |
| Contributions by utility customers for extensions to plant | | 10.3 | 13.2 | 50.9 | 45.7 |
| Non-current deferred electricity costs | | 4.0 | 10.3 | (5.9) | 19.1 |
| Changes in non-cash working capital | 15 | 12.1 | 9.9 | 9.1 | (26.4) |
| Other | | (1.1) | 5.4 | (3.2) | 2.5 |
| | | (112.2) | (95.6) | (389.9) | (330.6) |
| Financing activities | | | | | |
| Change in notes payable | | (96.0) | (42.0) | - | - |
| Deferred electricity cost obligation | | - | - | - | (51.0) |
| Issue of long term debt | | 300.0 | - | 480.0 | - |
| Repayment of long term debt | | - | - | (100.0) | (60.0) |
| Repayment of long term debt to parent corporation | | - | - | - | (1.0) |
| Dividends paid to Class A and Class B share owner | | (87.9) | (47.5) | (188.7) | (96.6) |
| Changes in non-cash working capital | 15 | - | - | - | 1.0 |
| Other | | (6.4) | 0.1 | (7.3) | (0.1) |
| | | 109.7 | (89.4) | 184.0 | (207.7) |
| Cash position ⁽¹⁾ | | | | | |
| Increase (decrease) | | 94.5 | (147.8) | 296.6 | (211.3) |
| Beginning of period | | (40.1) | (94.4) | (242.2) | (30.9) |
| End of period | | \$ 54.4 | \$(242.2) | \$ 54.4 | \$(242.2) |

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

CU INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2004

(tabular amounts in millions of Canadian dollars)

1. Summary of significant accounting policies

Financial Statement Presentation

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

Effective January 1, 2004, the Corporation prospectively adopted the Canadian Institute of Chartered Accountants (“CICA”) recommendations that define the primary sources of GAAP. Adoption of these recommendations had no effect on earnings for the three months and year ended December 31, 2004.

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

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the generating plants of Alberta Power (2000) are collectively referred to in these consolidated financial statements as the “regulated operations”.

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the Alberta Energy and Utilities Board (“AEUB”), which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AEUB may approve interim rates, subject to final determination.

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

On May 4, 2004, ATCO Gas and ATCO Electric closed the transfer of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (see Note 3). The Corporation’s revenues and natural gas supply and purchased power costs after May 4, 2004 will be reduced accordingly for 2004 and thereafter. ATCO Pipelines, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical did not participate in this transfer and continue to purchase natural gas and electricity for sale to customers. In addition, the AEUB issued a decision that directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon storage facility for the 2004/2005 storage year, which ends on March 31, 2005. Accordingly, ATCO Gas has entered into certain energy contracts for the forward purchase and sale of natural gas for storage purposes (see Note 18).

Accounting for regulated operations is described in Note 2.

1. Summary of significant accounting policies (continued)

Use of Estimates

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

Revenue Recognition

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

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

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

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

Revenues from ATCO Pipelines' regulated transportation of natural gas are recognized on the basis of contractual arrangements.

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. PPA incentives and penalties are recognized as described under the accounting policy for deferred availability incentives.

Natural Gas Supply

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

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

1. Summary of significant accounting policies (continued)

Purchased Power

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

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

Income Taxes

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

Inventories

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

Property, Plant and Equipment

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

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

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

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

Effective January 1, 2004, the Corporation prospectively adopted the CICA recommendations on accounting for asset impairment. These recommendations require an impairment of property, plant and equipment, intangible assets with finite lives, deferred operating costs and long term prepaid expenses to be recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques. This change in accounting had no effect on earnings for the three months and year ended December 31, 2004.

1. Summary of significant accounting policies (continued)

Deferred Financing Charges

Issue costs of long term debt are amortized over the weighted average life of the debt and issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption.

Deferred Availability Incentives

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

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

Asset Retirement Obligations

Effective January 1, 2004, the Corporation retroactively adopted the CICA recommendations on accounting for asset retirement obligations as described in Note 11. The CICA recommendations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques. The prior year's financial statements have been restated for the change in the method of accounting for asset retirement obligations.

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. Prior to January 1, 2004, site restoration and removal costs that are now accounted for as asset retirement obligations were accrued over the estimated remaining useful lives of the assets.

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

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)

Hedging

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

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

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

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

Employee Future Benefits

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

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

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

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

Stock Based Compensation Plans

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

2. Accounting for regulated operations

While CICA recommendations encourage the application of the primary sources of GAAP to all operations, the recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

Where regulatory decisions dictate, the Corporation defers certain costs or revenues as assets or liabilities in the balance sheet and records them as expenses or revenues in the earnings statement as it collects or refunds amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the regulator renders a subsequent decision. The Corporation anticipates that there would be no material differences between the amounts approved by the regulator for collection or refund and the amounts included in assets or liabilities on the balance sheet.

The Corporation has chosen to retain the following existing accounting policies, as permitted by CICA recommendations that define the primary sources of GAAP, pertaining to regulatory decisions that give rise to deferred assets or liabilities:

- a) *Purchased power* – Purchased power expense for the regulated operations in the Yukon Territory and the Northwest Territories is based on the actual cost of electricity purchased. The amount included in customer rates in the Yukon Territory is based on actual costs and in the Northwest Territories is based on forecast cost. Revenues are adjusted for variances from forecast cost, and the variances are deferred until such time as approval from the regulator is obtained for refund to or collection from customers.
- b) *Future removal and site restoration costs* – Depreciation rates for regulated assets, excluding Alberta Power (2000)'s generating plants, include a provision for future removal costs and site restoration costs (see Note 1 regarding the accounting policy for asset retirement obligations). On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.
- c) *Employee future benefits* – Costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), are recognized in earnings when paid rather than accrued. The differences between the amounts accrued on an actuarial basis and paid are deferred in other assets.
- d) Certain costs as required or permitted by the AEUB are deferred for recovery through future rates.

Similar accounting policies that pertained to the retail energy supply businesses that were transferred as of May 4, 2004 (see Note 3) included:

- a) *Natural gas supply* – Natural gas supply expense was based on the forecast cost of natural gas included in customer rates. Variances from forecast costs were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers and revenues and natural gas supply expense was adjusted accordingly.
- b) *Purchased power* – Purchased power expense in ATCO Electric was based on the actual cost of electricity purchased, whereas the amount included in customer rates was based on forecast cost. Revenues were adjusted for variances from forecast cost, and the variances were deferred until such time as approval from the AEUB was obtained for refund to or collection from customers.

3. Transfer of retail energy supply businesses

On May 4, 2004, ATCO Gas and ATCO Electric closed the transfer of their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. Proceeds of the transfer were \$90 million, of which \$45 million was paid at closing, with the remainder to be paid 12 months following closing. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the transfer of the retail energy supply businesses, resulted in a gain of \$63.3 million before income taxes of \$8.2 million. This transfer increased 2004 earnings by \$55.1 million.

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

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

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

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AEUB to do so), the agreements will terminate and the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

Centrica plc, DEML's parent, has provided a \$300 million guarantee supported by a \$235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek Business Services, an affiliate corporation, in respect of the ongoing relationships contemplated under the transaction agreements. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below \$200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and ATCO Electric.

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

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

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

4. Interest and other income

| | 2004 | 2003 |
|--|--------------|--------|
| Interest | \$2.9 | \$ 5.8 |
| Allowance for funds used by regulated operations | 6.2 | 4.4 |
| Other income (expense) | 0.3 | (0.2) |
| | \$9.4 | \$10.0 |

5. Income taxes

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

| | 2004 | | 2003 | |
|--|------------------|--------------|---------|-------|
| Earnings before income taxes | \$332.8 | % | \$296.1 | % |
| Income taxes, at statutory rates | \$136.0 | 40.9 | \$123.5 | 41.7 |
| Federal general tax reduction ⁽¹⁾ | (14.3) | (4.3) | (8.3) | (2.8) |
| Manufacturing and processing tax credit | (6.1) | (1.8) | (7.1) | (2.4) |
| Resource allowance | (2.2) | (0.7) | (2.4) | (0.8) |
| Crown royalties and other non-deductible Crown payments | 0.7 | 0.2 | 1.1 | 0.4 |
| Large Corporations Tax | 4.4 | 1.3 | 5.6 | 1.9 |
| Unrecorded future income taxes relating to regulated operations | 4.4 | 1.3 | 6.9 | 2.3 |
| Natural gas and other property disposals | - | - | (0.6) | (0.2) |
| Transfer of retail energy supply businesses | (12.1) | (3.6) | - | - |
| Change in method of accounting for future income taxes in certain regulated operations | (15.8) | (4.8) | (6.8) | (2.3) |
| Other | 2.2 | 0.7 | (4.6) | (1.6) |
| | 97.2 | 29.2 | 107.3 | 36.2 |
| Current income taxes | 124.5 | | 107.1 | |
| Future income taxes (recoveries) | \$ (27.3) | | \$ 0.2 | |

⁽¹⁾ The federal general tax reduction of 7% (2003 — 5%) is applicable to earnings that have not otherwise benefited from the manufacturing and processing tax credit and/or the resource allowance. An additional federal tax reduction of 2% (2003 — 1%) is applicable to earnings that have benefited from the resource allowance.

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

| | 2004 | 2003 |
|---|----------------|--------|
| Property, plant and equipment | \$ 78.1 | \$78.9 |
| Deferred assets and liabilities | (13.8) | 13.1 |
| Other | 0.2 | (0.5) |
| | 64.5 | 91.5 |
| Less: Amounts included in current future income taxes | (0.3) | 11.5 |
| | \$ 64.8 | \$80.0 |

Unrecorded future income tax liabilities of the regulated operations amounted to \$165.3 million at December 31, 2004. This balance includes \$38.8 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

There are tax loss carryforwards of \$0.9 million (2003 — \$0.2 million) for which no tax benefit has been recorded. These losses will expire in 2011.

Income taxes paid amounted to \$78.6 million (2003 — \$110.5 million).

6. Retained earnings at beginning of period as restated

| | Three Months Ended December 31 | | Year Ended December 31 | |
|--|-----------------------------------|-----------|---------------------------|---------|
| | 2004 | 2003 | 2004 | 2003 |
| Retained earnings at beginning of period as previously reported | \$1,070.7 | \$1,000.2 | \$1,007.1 | \$929.3 |
| Adjustment to retained earnings for prior years' effect of change in method of accounting for asset retirement obligations | - | (3.7) | (3.7) | (4.1) |
| Retained earnings at beginning of period as restated | \$1,070.7 | \$ 996.5 | \$1,003.4 | \$925.2 |

7. Property, plant and equipment

| | 2004 | | | 2003 | |
|--|------------------------------------|-----------|-----------------------------|-----------|-----------------------------|
| | Composite Depreciation Rates | Cost | Accumulated Depreciation | Cost | Accumulated Depreciation |
| Utilities | 3.6% | \$5,584.0 | \$2,081.4 | \$5,182.8 | \$1,926.8 |
| Power Generation | 3.3% | 1,298.9 | 613.3 | 1,267.0 | 572.3 |
| | | \$6,882.9 | 2,694.7 | \$6,449.8 | 2,499.1 |
| Property, plant and equipment less accumulated depreciation | | | 4,188.2 | | 3,950.7 |
| Unamortized contributions by utility customers for extensions to plant | | | 543.6 | | 512.2 |
| | | | \$3,644.6 | | \$3,438.5 |

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of \$297.9 million (2003 — \$285.7 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of \$75.6 million (2003 — \$75.6 million) and non-depreciable assets of \$30.1 million (2003 — \$28.9 million).

8. Other assets

| | 2004 | 2003 |
|---|--------|--------|
| Net accrued pension asset (Note 17) | \$23.0 | \$22.9 |
| Costs deferred for recovery through future regulated rates ⁽¹⁾ | 25.0 | 25.7 |
| Deferred costs related to the transfer of retail energy supply businesses | - | 10.8 |
| Deferred financing charges ⁽²⁾ | 9.0 | 7.3 |
| Other ⁽¹⁾ | 6.0 | 6.6 |
| | \$63.0 | \$73.3 |

⁽¹⁾ Amortization of certain other assets, which was recorded in depreciation and amortization, amounted to \$12.0 million in 2004 (2003 — \$5.0 million).

⁽²⁾ Amortization of deferred financing charges, which was recorded in interest expense, amounted to \$1.0 million in 2004 (2003 — \$1.1 million).

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

At December 31, 2004, the short term advances from parent and affiliate corporations consist of promissory notes of \$9.6 million (2003 — \$285.0 million), at interest rates from 2.49% to 2.53%, of which \$7.6 million matures on January 17, 2005 and \$2.0 million is repayable on demand.

At December 31, 2004, the Corporation has the following credit lines that enable it to obtain financing for general business purposes:

| | 2004 | | | 2003 | | |
|----------------------|----------------|---------------|----------------|----------------|---------------|----------------|
| | Total | Used | Available | Total | Used | Available |
| Short term committed | \$300.0 | \$17.0 | \$283.0 | \$300.0 | \$36.0 | \$264.0 |
| Uncommitted | 29.1 | 0.2 | 28.9 | 114.1 | 0.1 | 114.0 |
| | \$329.1 | \$17.2 | \$311.9 | \$414.1 | \$36.1 | \$378.0 |

All of the \$17.2 million used at December 31, 2004 represents outstanding letters of credit.

10. Long term debt

| | 2004 | 2003 |
|--|------------------|------------------|
| <i>Long term debt</i> | | |
| Debentures – unsecured | | |
| 1994 Series 8.73% due June 2004 | \$ - | \$ 100.0 |
| 1995 Series 8.43% due June 2005 | 125.0 | 125.0 |
| 2001 4.84% due November 2006 | 175.0 | 175.0 |
| 2002 4.801% due November 2007 | 50.0 | 50.0 |
| 2000 6.97% due June 2008 | 100.0 | 100.0 |
| 1989 Series 10.20% due November 2009 | 125.0 | 125.0 |
| 1990 Series 11.40% due August 2010 | 125.0 | 125.0 |
| 2000 7.05% due June 2011 | 100.0 | 100.0 |
| 2004 5.096% due November 2014 | 100.0 | - |
| 2002 6.145% due November 2017 | 150.0 | 150.0 |
| 2004 5.432% due January 2019 | 180.0 | - |
| 1999 Series 6.8% due August 2019 | 300.0 | 300.0 |
| 1990 Second Series 11.77% due November 2020 | 100.0 | 100.0 |
| 1991 Series 9.92% due April 2022 | 125.0 | 125.0 |
| 1992 Series 9.40% due May 2023 | 100.0 | 100.0 |
| 2004 5.896% due November 2034 | 200.0 | - |
| Other long term obligation, at 4.25%, due June 2006, unsecured | 4.5 | 4.5 |
| | 2,059.5 | 1,679.5 |
| <i>Long term debt to parent corporation</i> | | |
| Non-interest bearing promissory note, unsecured | 3.0 | 3.0 |
| | \$2,062.5 | \$1,682.5 |

Minimum debt repayments

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

| 2005 | 2006 | 2007 | 2008 | 2009 |
|---------|---------|--------|---------|---------|
| \$125.0 | \$179.5 | \$50.0 | \$100.0 | \$125.0 |

The amount due in 2005 is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

10. Long term debt (continued)

Interest expense

Interest on debt is as follows:

| | 2004 | 2003 |
|--------------------------------------|----------------|----------------|
| Long term debt | \$142.3 | \$140.1 |
| Long term debt to parent corporation | - | 0.1 |
| Notes payable | 0.7 | 0.6 |
| Current bank indebtedness | 0.9 | 1.9 |
| Amortization of financing charges | 1.0 | 1.1 |
| | \$144.9 | \$143.8 |

Interest paid amounted to \$138.0 million (2003 — \$143.8 million).

Fair values

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

| | 2004 | 2003 |
|---|-----------|-----------|
| Long term debt – Fixed rate | \$2,426.8 | \$1,990.8 |
| Long term debt to parent corporation – Fixed rate | \$ 3.0 | \$ 3.0 |

11. Deferred credits

| | 2004 | 2003 |
|--------------------------------------|----------------|----------------|
| Deferred availability incentives | \$ 46.1 | \$ 43.3 |
| Asset retirement obligations | 27.4 | 25.9 |
| Deferred electricity cost recoveries | 10.3 | 16.2 |
| Deferred royalty credits | 14.1 | 10.3 |
| Deferred revenues | 6.8 | 3.1 |
| Other | 18.1 | 14.3 |
| | \$122.8 | \$113.1 |

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to \$7.6 million in 2004 (2003 – \$7.5 million).

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

11. Deferred credits (continued)

Asset retirement obligations

The CICA recommendations on accounting for asset retirement obligations require the Corporation to identify legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques.

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

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

| | Three Months Ended December 31 | | Year Ended December 31 | |
|---|-----------------------------------|---------|---------------------------|-------------------|
| | 2004 | 2003 | 2004 | 2003 |
| | <i>(Unaudited)</i> | | | |
| <i>Statement of earnings</i> | | | | |
| Depreciation and amortization | \$(0.2) | \$(0.3) | \$(1.0) | \$(1.8) |
| Accretion expense, included in depreciation and amortization | 0.4 | 0.3 | 1.5 | 1.4 |
| Earnings attributable to Class A and Class B shares | \$(0.2) | \$ - | \$(0.5) | \$ 0.4 |
| | | | | January 1 2003 |
| <i>Balance sheet</i> | | | | |
| Retirement assets and site restoration and removal costs, included in property, plant and equipment | | | | \$20.4 |
| Asset retirement obligations, included in deferred credits | | | | 24.5 |
| Retained earnings at beginning of period | | | | (4.1) |

Changes in asset retirement obligations are summarized below:

| | Three Months Ended December 31 | | Year Ended December 31 | |
|------------------------------------|-----------------------------------|--------|---------------------------|--------|
| | 2004 | 2003 | 2004 | 2003 |
| | <i>(Unaudited)</i> | | | |
| Obligations at beginning of period | \$27.0 | \$25.6 | \$25.9 | \$24.5 |
| Accretion expense | 0.4 | 0.3 | 1.5 | 1.4 |
| Obligations at end of period | \$27.4 | \$25.9 | \$27.4 | \$25.9 |

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

12. Equity preferred shares to parent corporation

Authorized and issued

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

Issued:

| | Stated Value (dollars) | Redemption Dates | 2004 | | 2003 | |
|---|------------------------------|---------------------|------------------|----------------|-----------|----------------|
| | | | Shares | Amount | Shares | Amount |
| Cumulative Redeemable Second Preferred Shares | | | | | | |
| 5.9% Series Q | \$25.00 | Open | 2,277,675 | \$ 56.9 | 2,277,675 | \$ 56.9 |
| 5.3% Series R | \$25.00 | Open | 2,146,730 | 53.7 | 2,146,730 | 53.7 |
| 6.6% Series S | \$25.00 | Open | 635,700 | 15.9 | 635,700 | 15.9 |
| Perpetual Cumulative Second Preferred Shares | | | | | | |
| 5.05% Series U | \$25.00 | December 2, 2006 | 800,000 | 20.0 | 800,000 | 20.0 |
| 5.25% Series V | \$25.00 | October 3, 2007 | 4,400,000 | 110.0 | 4,400,000 | 110.0 |
| | | | | \$256.5 | | \$256.5 |

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

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are \$262.5 million (2003 — \$263.8 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.

13. Class A and Class B shares

| | Class A Non-Voting | | Class B Common | | Total | |
|----------------------------|--------------------|----------------|----------------|----------------|------------|----------------|
| | Shares | Amount | Shares | Amount | Shares | Amount |
| Authorized: | Unlimited | | Unlimited | | | |
| Issued and outstanding: | 134 | \$252.7 | 76 | \$154.9 | 210 | \$407.6 |

14. Stock based compensation plans

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading prices of the Class A non-voting shares and the Class I Non-Voting shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and the Class I Non-Voting shares, respectively, over the base value of the share appreciation rights exercised. Share appreciation rights expense amounted to nil (2003 — nil).

15. Changes in non-cash working capital

| | 2004 | 2003 |
|--|-----------------|-----------------|
| <i>Operating activities, changes related to:</i> | | |
| Accounts receivable | \$ 242.5 | \$(84.1) |
| Accounts receivable from parent and affiliate corporations | (8.2) | 2.2 |
| Inventories | (1.6) | (53.4) |
| Deferred natural gas costs | 28.1 | 4.0 |
| Deferred electricity costs | 10.7 | 21.7 |
| Prepaid expenses | 0.2 | (0.2) |
| Accounts payable and accrued liabilities | (120.4) | 22.4 |
| Accounts payable to parent and affiliate corporations | (57.4) | 36.3 |
| Income taxes | 35.0 | (5.1) |
| Future income taxes | (9.0) | (5.3) |
| | \$ 119.9 | \$(61.5) |
| <i>Investing activities, changes related to:</i> | | |
| Inventories | \$ (0.2) | \$ 0.5 |
| Prepaid expenses | (0.1) | 0.3 |
| Accounts payable and accrued liabilities | 1.2 | (27.2) |
| Income taxes | 11.0 | - |
| Future income taxes | (2.8) | - |
| | \$ 9.1 | \$(26.4) |
| <i>Financing activities, changes related to:</i> | | |
| Accounts receivable | \$ - | \$ 0.8 |
| Accounts receivable from parent and affiliate corporations | - | 0.2 |
| | \$ - | \$ 1.0 |

16. Related party transactions

| Entity | Relationship | Transaction | Recorded As | 2004 | 2003 |
|---|--------------|---|---|---------------|--------|
| Canadian Utilities Limited ⁽¹⁾ | Parent | Sale of electricity and natural gas, lease of land, rent and office services | Revenues | \$ 0.5 | \$ 1.5 |
| | | Administration, rent, aircraft usage, bank activity charges, computer operations and systems development, financial management, and payroll and accounting services | Operation and maintenance, selling and administrative | 7.1 | 33.0 |
| | | Purchase of equipment, leasehold improvements and capitalized software | Property, plant and equipment | 0.7 | 11.9 |
| ATCO Ltd. and ATCO Investments Ltd. | Affiliates | Corporate signature rights and rent | Selling and administrative | 2.6 | 2.6 |

16. Related party transactions (continued)

| Entity | Relationship | Transaction | Recorded As | 2004 | 2003 |
|---|--------------|--|--|--------------|-------|
| ASHCOR Technologies Ltd., ATCO Frontec Corp., ATCO I-Tek Inc. ⁽¹⁾ , ATCO I-Tek Business Services Ltd., ATCO Midstream Ltd., ATCO Power Ltd., ATCO Utility Services Ltd., And Genics Inc. | Affiliates | Natural gas storage, transportation and other gas services, sale of electricity, rent and office services | Revenues | 16.4 | 15.7 |
| | | Purchase and storage of natural gas | Natural gas supply | 218.1 | 518.8 |
| | | Purchase of natural gas | Operation and maintenance | 9.2 | 13.3 |
| | | Gas management fees, computer operations and systems development, call centre and customer billing services, information services, property management and security services, contract labor, payroll and accounting services | Operation and maintenance, selling and administrative | 84.5 | 72.3 |
| | | North Warning System joint venture earnings | Other income | 0.1 | 0.2 |
| | | Purchase of equipment, capitalized costs and capitalized software | Property, plant and equipment | 21.7 | 7.5 |
| | | Costs related to disposition of retail energy businesses | Other assets | - | 1.1 |

⁽¹⁾ Effective January 1, 2004, the ATCO I-Tek division of Canadian Utilities Limited was incorporated as ATCO I-Tek Inc. Therefore, the Corporation's related party transactions with ATCO I-Tek Inc. in 2004 are reported as transactions with an affiliate corporation rather than with the parent corporation.

The Corporation incurred advertising and promotion expenses from an entity related through common control totaling \$0.2 million (2003 — \$0.2 million).

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

17. Employee future benefits

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

Contributions to the Group Plan, which is accounted for as a defined contribution pension plan, are expensed as paid. Other post employment benefit and certain other group defined benefit pension plans, which the Corporation funds out of general revenues, are administered on a combined basis with Canadian Utilities Limited and its subsidiary corporations. For other post employment benefits, the Corporation is assessed a percentage of its payroll at a rate calculated for each plan as a whole; for certain other defined benefit pensions, the Corporation is assessed a percentage of the total cost of the plans. Pursuant to an AEUB decision effective January 1, 2000, the regulated

17. Employee future benefits (continued)

operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. The differences between the amounts accrued and paid are deferred in other assets.

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

| | 2004 | | 2003 | |
|---|-----------------------|-------------------------------------|-----------------------|-------------------------------------|
| | Pension Benefit Plans | Other Post Employment Benefit Plans | Pension Benefit Plans | Other Post Employment Benefit Plans |
| <i>Benefit plan cost:</i> | | | | |
| Total cost | \$ 4.5 | \$ 6.4 | \$ 4.2 | \$ 6.5 |
| Less: Capitalized | 1.2 | 2.0 | 1.0 | 2.0 |
| Less: Regulatory deferral ⁽¹⁾ | 1.1 | 2.6 | 1.2 | 2.7 |
| Net cost recognized | \$ 2.2 | \$ 1.8 | \$ 2.0 | \$ 1.8 |
| <i>Accrued benefit plan assets and liabilities:</i> | | | | |
| Accrued asset (liability) at beginning of year | \$11.5 | \$(13.0) | \$13.1 | \$(8.7) |
| Total cost | (4.5) | (6.4) | (4.2) | (6.5) |
| Benefit payments | 2.8 | 2.3 | 2.6 | 2.2 |
| Accrued asset (liability) at end of year | 9.8 | (17.1) | 11.5 | (13.0) |
| Regulatory asset ⁽¹⁾ | 13.2 | 16.8 | 11.4 | 12.8 |
| Net accrued asset (liability) recognized (Note 8) | \$23.0 | \$ (0.3) | \$22.9 | \$(0.2) |

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

Weighted average assumptions

| | 2004 | | 2003 | |
|---|-----------------------|-------------------------------------|-----------------------|-------------------------------------|
| | Pension Benefit Plans | Other Post Employment Benefit Plans | Pension Benefit Plans | Other Post Employment Benefit Plans |
| <i>Assumptions regarding benefit plan cost:</i> | | | | |
| Liability discount rate for the year | 6.25% | 6.25% | 6.5% | 6.5% |
| Average compensation increase for the year | 3.0% | - | 2.75% | - |
| <i>Assumptions regarding accrued benefit obligations:</i> | | | | |
| Liability discount rate at December 31 | 5.9% | 5.9% | 6.25% | 6.25% |
| Long term inflation rate | 2.5% | (1) | 2.5% | (1) |

⁽¹⁾ The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 9.9% for 2004 grading down over 9 years to 4.5% (2003 – 10.5% for 2003 grading down over 10 years to 4.5%), and, for other medical and dental costs, 4.0% for 2004 and thereafter (2003 – 4.0% for 2003 and thereafter).

17. Employee future benefits (continued)

Funding

Employees are required to contribute a percentage of their salary to the defined benefit pension plans. The Corporation is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2002, the Corporation is continuing a contribution holiday that began on April 1, 1996. The next actuarial valuation for funding purposes is required as of December 31, 2005.

18. Risk management and financial instruments

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

Foreign exchange rate risk

The Corporation has entered into foreign exchange forward contracts in order to fix the exchange rate on certain planned equipment expenditures denominated in U.S. dollars. At December 31, 2004, there were no contracts outstanding to purchase U.S. dollars (2003 — \$0.5 million U.S.).

Energy commodity price risk

In March 2004, the AEUB issued a decision respecting the operation of ATCO Gas' Carbon storage facility for the 2004/2005 storage year, which ends on March 31, 2005. The decision directed ATCO Gas to continue to reserve 16.7 petajoules of storage capacity for the benefit of utility customers. As a result of an AEUB approved storage plan, ATCO Gas has entered into certain energy contracts for the forward purchase and sale of natural gas for storage purposes. All associated costs and benefits of these contracts are passed to customers through regulated rates and, accordingly, ATCO Gas does not bear any risk for price fluctuations provided that the contracts are in accordance with the storage plan. At December 31, 2004, the contracts consist of natural gas sales of 12,802 terajoules ("TJ") for \$76.3 million (2003 — 151 TJ for \$1.0 million) and natural gas purchases of 107 TJ for \$0.6 million (2003 — 151 TJ for \$1.0 million).

Fair values

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

| | 2004 | | | 2003 | | |
|---------------------------------------|-----------------------|---------------------------------------|----------|-----------------------|---------------------------------------|----------|
| | Notional Principal | Fair Value (Payable) Receivable | Maturity | Notional Principal | Fair Value (Payable) Receivable | Maturity |
| Foreign exchange forward contracts | - | - | - | \$0.7 | Nil | 2004 |

Credit risk

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

19. Commitments and contingencies

Commitments

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

| 2005 | 2006 | 2007 | 2008 | 2009 | Total of All Subsequent Years |
|-------|-------|-------|-------|-------|----------------------------------|
| \$8.1 | \$7.7 | \$7.4 | \$6.9 | \$3.6 | \$5.5 |

Contingencies

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

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

20. Regulatory matters

In a decision dated October 2, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.40% and a common equity ratio of 32% for ATCO Electric's transmission operations and 35% for its distribution operations for 2003. These reductions in the common equity ratios reduced the common equity that ATCO Electric was allowed to earn a return on by \$83.0 million for 2003. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress. In a decision dated July 2, 2004, the AEUB issued its Generic Cost of Capital decision (as described below) which approved, among other things, a return on common equity of 9.60% for 2004 and a common equity ratio of 33% for ATCO Electric's transmission operations and 37% for its distribution operations beginning in 2004. These increases in the common equity ratios increased the common equity that ATCO Electric was allowed to earn a return on by \$22.3 million for 2004 as compared to 2003.

In a decision dated October 1, 2003, the AEUB approved for ATCO Gas, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37% for 2003 and 2004. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress. In a decision dated July 2, 2004, the AEUB issued its Generic Cost of Capital decision which approved, among other things, ATCO Gas' common equity ratio of 38% beginning in 2005. As ATCO Gas' return on common equity for 2004 was already established, the standardized approach approved by the AEUB in its Generic Cost of Capital decision for determining the return on common equity will be applied beginning in 2005.

In a decision dated December 2, 2003, the AEUB approved for ATCO Pipelines, among other things, a rate of return on common equity of 9.50% and a common equity ratio of 43.5% for 2003. In a decision dated July 13, 2004, the AEUB awarded additional revenue with respect to the revenue forecasts of certain industrial customers. The decision also set aside certain transactions with affiliates that will be addressed in a separate proceeding, currently in progress. In a decision dated July 2, 2004, the AEUB issued its Generic Cost of Capital decision which approved, among other things, ATCO Pipelines' return on common equity of 9.60% for 2004 and a common equity ratio of 43% beginning in 2004.

The Generic Cost of Capital decision established a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity based upon a return of 9.60% on common equity. This rate of return will be adjusted annually by 75% of the change in long term Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Canada bond yields for the month of October as reported in the National Post. This adjustment mechanism is the same as the National Energy Board uses in determining its formula based rate of return. The AEUB will undertake a review of

20. Regulatory matters (continued)

this mechanism for the year 2009 or if the rate of return resulting from the formula is less than 7.6% or greater than 11.6%. The AEUB also noted that any party, at any time, could petition for a review of the adjustment formula if that party can demonstrate a material change in facts or circumstances.

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

In November 2004, the AEUB announced a generic return on common equity of 9.50% for 2005. The AEUB also announced that the 2005 generic return on equity would only apply to utilities which file rate applications in 2005. If no rate applications are filed, then existing return on common equity rates will continue to apply.

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

21. Segmented information

Description of segments

The Corporation operates under a management reporting structure that is reflected in the following business segments:

The **Utilities** segment includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transportation of natural gas by ATCO Pipelines, and the regulated transmission and distribution of water by CU Water. This segment was formerly known as Natural Gas and Electric; its composition has remained unchanged.

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

Segmented results – Three months ended December 31

| 2004 | | Power | Corporate | Intersegment | |
|--|----------------|---------------|--------------|----------------|----------------|
| 2003 | Utilities | Generation | and Other | Eliminations | Consolidated |
| <i>(Unaudited)</i> | | | | | |
| Revenues – external | \$297.6 | \$74.1 | \$ - | \$ - | \$371.7 |
| | \$646.0 | \$82.1 | \$ - | \$ - | \$728.1 |
| Revenues – intersegment ⁽¹⁾ | 0.1 | - | - | (0.1) | - |
| | 1.8 | - | - | (1.8) | - |
| Revenues | \$297.7 | \$74.1 | \$ - | \$(0.1) | \$371.7 |
| | \$647.8 | \$82.1 | \$ - | \$(1.8) | \$728.1 |
| Earnings attributable to | \$ 38.6 | \$14.6 | \$0.3 | \$ - | \$ 53.5 |
| Class A and Class B shares | \$ 38.7 | \$15.7 | \$ - | \$ - | \$ 54.4 |

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

21. Segmented information (continued)

Segmented results – Year ended December 31

| 2004 2003 | Utilities | Power Generation | Corporate and Other | Intersegment Eliminations | Consolidated |
|---|-------------------------------|---------------------------|---------------------------|------------------------------|-------------------------------|
| Revenues – external | \$1,786.4 \$2,527.0 | \$292.3 \$319.2 | \$ - \$ - | \$ - \$ - | \$2,078.7 \$2,846.2 |
| Revenues – intersegment ⁽¹⁾ | 2.4 6.6 | - - | - - | (2.4) (6.6) | - - |
| Revenues | 1,788.8 2,533.6 | 292.3 319.2 | - - | (2.4) (6.6) | 2,078.7 2,846.2 |
| Operating expenses | 1,328.2 2,067.9 | 125.5 147.9 | - - | (2.4) (6.6) | 1,451.3 2,209.2 |
| Depreciation and amortization | 178.6 165.9 | 43.8 41.2 | - - | - - | 222.4 207.1 |
| Interest expense | 118.5 113.9 | 28.3 30.1 | 142.7 140.6 | (144.6) (140.8) | 144.9 143.8 |
| Gain on transfer of retail energy supply businesses | (63.3) - | - - | - - | - - | (63.3) - |
| Interest and other income | (8.6) (9.1) | (0.8) (1.1) | (144.6) (140.6) | 144.6 140.8 | (9.4) (10.0) |
| Earnings before income taxes | 235.4 195.0 | 95.5 101.1 | 1.9 - | - - | 332.8 296.1 |
| Income taxes | 56.4 66.3 | 40.2 41.0 | 0.6 - | - - | 97.2 107.3 |
| | 179.0 128.7 | 55.3 60.1 | 1.3 - | - - | 235.6 188.8 |
| Dividends on equity preferred shares to parent corporation | 10.4 10.4 | 3.6 3.6 | - - | - - | 14.0 14.0 |
| Earnings attributable to Class A and Class B shares | \$ 168.6 \$ 118.3 | \$ 51.7 \$ 56.5 | \$ 1.3 \$ - | \$ - \$ - | \$ 221.6 \$ 174.8 |
| Total assets | \$3,396.4 \$3,409.3 | \$787.0 \$796.2 | \$ 1.7 \$ 0.4 | \$ (0.1) \$ (0.5) | \$4,185.0 \$4,205.4 |
| Purchase of property, plant and equipment | \$ 426.3 \$ 345.4 | \$ 32.0 \$ 37.9 | \$ - \$ - | \$ - \$ - | \$ 458.3 \$ 383.3 |

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