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CANADIAN UTILITIES LIMITED

An ATCO Company

AR/S
12-31-03

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2003

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
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February 6, 2004, except as to note 21,
which is as of February 17, 2004

Auditors' Report

To the Share Owners of
Canadian Utilities Limited

We have audited the consolidated balance sheets of **Canadian Utilities Limited** as at December 31, 2003 and 2002 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, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta

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

	Note	Three Months Ended December 31		Year Ended December 31	
		2003	2002	**2003**	2002
		(Unaudited)			
Revenues		**$ 950.3**	$ 930.7	**$3,742.6**	$2,975.9
Costs and expenses					
Natural gas supply		**368.6**	358.1	**1,519.8**	991.7
Purchased power		**46.8**	59.6	**209.8**	184.4
Operation and maintenance		**216.1**	219.1	**858.4**	759.9
Selling and administrative		**52.7**	38.2	**158.1**	136.0
Depreciation and amortization		**72.7**	67.9	**268.9**	244.4
Interest	10	**47.1**	45.3	**190.3**	184.1
Franchise fees		**30.5**	28.9	**122.6**	98.5
		834.5	817.1	**3,327.9**	2,599.0
		115.8	113.6	**414.7**	376.9
Gain on sale of Viking-Kinsella property	2	**-**	1.6	**-**	110.1
Interest and other income	3	**9.5**	7.8	**33.4**	26.1
Earnings before income taxes		**125.3**	123.0	**448.1**	513.1
Income taxes	4	**29.7**	44.3	**155.7**	189.9
		95.6	78.7	**292.4**	323.2
Dividends on equity preferred shares		**8.9**	5.2	**33.1**	18.2
Earnings attributable to Class A and Class B shares	2	**86.7**	73.5	**259.3**	305.0
Retained earnings at beginning of period		**1,385.3**	1,275.2	**1,314.9**	1,136.9
		1,472.0	1,348.7	**1,574.2**	1,441.9
Dividends on Class A and Class B shares		**32.3**	31.0	**129.3**	124.2
Direct charges	5	**0.9**	2.8	**6.1**	2.8
Retained earnings at end of period		**$1,438.8**	$1,314.9	**$1,438.8**	$1,314.9
Earnings per Class A and Class B share	13	**$ 1.37**	$ 1.16	**$ 4.09**	$ 4.81
Diluted earnings per Class A and Class B share	13	**$ 1.36**	$ 1.15	**$ 4.07**	$ 4.79
Dividends paid per Class A and Class B share		**$ 0.51**	$ 0.49	**$ 2.04**	$ 1.96

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

	Note	December 31 2003	2002
ASSETS			
Current assets			
Cash and short term investments	16	**$ 328.1**	$ 438.9
Accounts receivable		**540.6**	459.4
Inventories		**171.3**	121.7
Income taxes recoverable		**10.2**	20.2
Deferred natural gas costs		**27.2**	31.2
Deferred electricity costs		**-**	20.7
Prepaid expenses		**25.6**	25.4
		1,103.0	1,117.5
Property, plant and equipment	6	**4,809.4**	4,657.0
Security deposits for debt		**23.1**	26.1
Other assets	7	**135.0**	133.8
		$6,070.5	$5,934.4
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Bank indebtedness		**$ -**	$ 5.0
Accounts payable and accrued liabilities		**478.8**	451.3
Future income taxes	4	**11.5**	16.8
Deferred electricity cost recoveries		**1.0**	-
Deferred electricity cost obligation	9	**-**	51.0
Non-recourse long term debt due within one year	10	**46.3**	46.1
		537.6	570.2
Future income taxes	4	**227.0**	230.8
Deferred credits	11	**106.4**	78.8
Long term debt	10	**1,805.3**	1,916.9
Non-recourse long term debt	10	**806.1**	821.1
Equity preferred shares	12	**636.5**	486.5
Class A and Class B share owners' equity			
Class A and Class B shares	13	**510.5**	509.6
Retained earnings		**1,438.8**	1,314.9
Foreign currency translation adjustment		**2.3**	5.6
		1,951.6	1,830.1
		$6,070.5	$5,934.4

N.C. Southern

N.C. SOUTHERN
DIRECTOR

B.K. French

B.K. FRENCH
DIRECTOR

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

	Note	Three Months Ended December 31 2003	2002	Year Ended December 31 2003	2002
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 86.7**	$ 73.5	**$ 259.3**	$ 305.0
Adjustments for:					
Depreciation and amortization		**72.7**	67.9	**268.9**	244.4
Future income taxes		**(6.2)**	22.3	**(0.3)**	20.7
Gain on sale of Viking-Kinsella property - net of current income taxes	2	**-**	(0.6)	**-**	(67.3)
Other - net		**0.1**	8.4	**(2.1)**	1.8
Cash flow from operations		**153.3**	171.5	**525.8**	504.6
Changes in non-cash working capital	15	**(82.8)**	(58.6)	**(52.8)**	(160.0)
		70.5	112.9	**473.0**	344.6
Investing activities					
Purchase of property, plant and equipment		**(176.7)**	(155.1)	**(495.7)**	(569.8)
Sale of Viking-Kinsella property - net of current income taxes	2	**-**	0.8	**-**	107.7
Proceeds on disposal of other property, plant and equipment		**11.3**	1.0	**23.8**	1.7
Contributions by utility customers for extensions to plant		**13.8**	21.2	**48.1**	41.1
Non-current deferred electricity costs		**10.3**	(10.4)	**19.1**	18.7
Changes in non-cash working capital	15	**15.3**	(4.8)	**(30.0)**	(8.3)
Other		**1.0**	1.0	**0.7**	(10.4)
		(125.0)	(146.3)	**(434.0)**	(419.3)
Financing activities					
Change in notes payable		**(42.0)**	(7.2)	**-**	(4.6)
Deferred electricity cost obligation	9	**-**	(14.9)	**(51.0)**	51.0
Issue of long term debt		**12.0**	300.0	**25.5**	300.0
Issue of non-recourse long term debt		**-**	4.8	**40.7**	173.0
Repayment of long term debt		**(66.8)**	(200.8)	**(139.1)**	(241.9)
Repayment of non-recourse long term debt		**(5.5)**	(4.5)	**(38.0)**	(43.7)
Issue of equity preferred shares		**-**	150.0	**150.0**	150.0
Issue (purchase) of Class A shares		**0.1**	0.1	**(2.4)**	2.9
Dividends paid to Class A and Class B share owners		**(32.3)**	(31.0)	**(129.3)**	(124.2)
Changes in non-cash working capital	15	**1.7**	0.6	**7.9**	8.7
Other		**(2.4)**	(11.3)	**(4.2)**	(11.1)
		(135.2)	185.8	**(139.9)**	260.1
Foreign currency translation		**0.6**	1.4	**(4.9)**	5.6
Cash position (1)					
Increase (decrease)		**(189.1)**	153.8	**(105.8)**	191.0
Beginning of period		**517.2**	280.1	**433.9**	242.9
End of period		**$ 328.1**	$ 433.9	**$ 328.1**	$ 433.9

(1) Cash position includes cash and short term investments less current bank indebtedness.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2003
(tabular amounts in millions of Canadian dollars)

1. Summary of significant accounting policies

Financial Statement Presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments ("Canadian Utilities"). Principal operations are Utilities (ATCO Electric, ATCO Gas), Power Generation (ATCO Power, Alberta Power (2000)), Logistics and Energy Services (ATCO Pipelines, ATCO Midstream, ATCO Frontec) and Technologies (ATCO I-Tek Business Services, ATCO I-Tek). Significant joint venture investments consist principally of power generation plants.

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

Regulation

ATCO Electric, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd., and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., are collectively referred to in these consolidated financial statements as the "regulated operations".

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 life of the related generating plant and December 31, 2020.

Use of Estimates

The preparation of Canadian Utilities' 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 employee future benefits, using currently available information. Changes in facts and circumstances may result in revised estimates, and actual results could differ from those estimates.

Revenue Recognition

Revenues from sales of natural gas and electricity by the regulated operations, excluding Alberta Power (2000), are recognized upon delivery, primarily on the basis of meter readings, and include an estimate of services provided but 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.

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

Revenues from the transportation and storage of natural gas are recognized on the basis of contractual arrangements for access. Revenues from sales of marketed natural gas and other energy products are recognized upon delivery. Revenues from the supply of contracted services are recorded by the percentage of completion method. Full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided.

Natural Gas Supply

Natural gas supply expense is based on the forecast cost of natural gas included in customer rates. Variances from forecast costs are deferred until such time as approval from the AEUB is obtained for refund to or collection from customers and revenues and natural gas supply expense are adjusted accordingly.

Purchased Power

Purchased power expense is based on the actual cost of electricity purchased, whereas the amount included in customer rates 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 AEUB is obtained for refund to or collection from customers.

Income Taxes

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

Other subsidiaries follow the liability method of accounting for income taxes. Under this method, future tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax liabilities and assets are measured using enacted and substantively enacted tax rates. The effect on future tax liabilities and assets of a change in tax rates is recognized in income in the period that the change occurs.

Inventories

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

Property, Plant and Equipment

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

Certain regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the AEUB for debt and equity capital. Property, plant and equipment in the other subsidiaries include capitalized interest incurred during construction.

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

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates for regulated assets are approved by the AEUB or, in the case of Alberta Power (2000)'s generating plants, are determined by the PPA's. These depreciation rates include a provision for future removal costs and site restoration costs. On retirement of depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

1. Summary of significant accounting policies (continued)

When events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, the carrying value is compared to the estimated future net cash flows from its use together with its residual value. Any excess of the carrying value over the net recoverable amount is expensed.

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, Canadian Utilities is subject to an incentive/penalty regime related to generating unit availability. Incentives are paid to Canadian Utilities by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by Canadian Utilities 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.

Long Term Debt Due Within One Year

When Canadian Utilities 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 Canadian Utilities' behalf with respect thereto, or sufficient capacity under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Hedging

During 2003, Canadian Utilities adopted the Canadian Institute of Chartered Accountants ("CICA") Accounting Guideline pertaining to the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting.

In conducting its business, Canadian Utilities 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.

Canadian Utilities designates each derivative instrument as a hedge of specific assets or liabilities on the balance sheet or specific firm commitments or anticipated transactions. Canadian Utilities 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.

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

Employee Future Benefits

Canadian Utilities accrues for its obligations under defined benefit pension and other post employment benefit plans. Costs of these benefits are determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs.

Pension plan assets at the end of the year are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

Experience gains and losses and the effect of changes in assumptions in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, adjustments resulting from plan amendments and the net transitional liability or asset, which arose upon the adoption in 2000 of the current accounting standard, are amortized over the estimated average remaining service life of employees.

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

Stock Based Compensation Plans

The Canadian Utilities Limited stock option plan and share appreciation rights are described in Note 14.

While the recommendations of the CICA on accounting for stock based compensation and other stock based payments require the adoption on or before January 1, 2004 of the fair value based method of accounting for stock options, other methods of accounting are permitted until that date. Canadian Utilities has chosen to retain its existing accounting policy, which is permitted by the recommendations, whereby no compensation expense is recognized upon the granting or exercise of stock options. Any consideration paid by holders of the stock options upon exercise is credited to share capital. While the recommendations require expense recognition for options that may be settled in cash or other assets, Canadian Utilities amended its stock option policy in June 2002 so that stock options will no longer be repurchased. Prior to that date, if stock options were repurchased, the consideration paid to the holders of the options was charged to retained earnings.

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, any change in compensation expense is recognized monthly in earnings.

Foreign Currency Translation

Assets and liabilities of self-sustaining foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of self-sustaining foreign operations are included in the foreign currency translation adjustment in share owners' equity.

Transactions denominated in foreign currencies are translated into Canadian dollars at the rate of exchange in effect at the transaction date. Monetary assets and liabilities of integrated foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date, non-monetary assets and liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred, and revenues and expenses are translated at the average monthly rates of exchange during the year. Gains or losses on translation of integrated foreign operations are recognized in earnings.

2. Gain on sale of Viking-Kinsella property

In 2002, Canadian Utilities sold its Viking-Kinsella natural gas producing property, which had a net book value of approximately $40 million, for $550 million. In accordance with an AEUB decision, $385.0 million plus related adjustments for future abandonment and future income taxes of $20.6 million, for a total of $405.6 million, was distributed to customers by way of lump sum payments.

Canadian Utilities' share of the net proceeds was $150.5 million, after adjustments, resulting in a gain of $110.1 million, before income taxes of $42.8 million. This sale increased earnings by $67.3 million.

3. Interest and other income

	2003	2002
Interest	**$24.3**	$17.1
Allowance for funds used by regulated operations	**4.4**	3.6
Other	**4.7**	5.4
	$33.4	$26.1

4. Income taxes

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

	2003		2002	
Earnings before income taxes	**$448.1**	%	$513.1	%
Income taxes, at statutory rates	**$187.0**	**41.7**	$216.7	42.2
Federal general tax reduction [(1)]	**(10.9)**	**(2.4)**	(9.1)	(1.8)
Manufacturing and processing tax credit	**(8.1)**	**(1.8)**	(7.3)	(1.4)
Resource allowance	**(3.5)**	**(0.8)**	(3.3)	(0.6)
Crown royalties and other non-deductible Crown payments	**1.1**	**0.3**	1.8	0.3
Large Corporations Tax	**8.1**	**1.8**	7.1	1.4
Foreign tax rate variance	**(2.6)**	**(0.6)**	(5.2)	(1.0)
Non-deductible interest on foreign financing	**1.5**	**0.3**	1.4	0.3
Change in future income taxes resulting from reduction in tax rates	**(2.1)**	**(0.5)**	(1.8)	(0.4)
Unrecorded future income taxes relating to regulated operations	**7.1**	**1.6**	4.9	1.0
Natural gas and other property disposals	**(0.6)**	**(0.1)**	(10.8)	(2.1)
Reduction in future income taxes resulting from a change in tax legislation in Australia	**(8.9)**	**(2.0)**	-	-
Change in method of accounting for future income taxes in certain regulated operations	**(6.8)**	**(1.5)**	-	-
Other	**(5.6)**	**(1.2)**	(4.5)	(0.9)
	155.7	**34.8**	189.9	37.0
Current income taxes	**158.6**		151.4	
Future income taxes (recoveries)	**$ (2.9)**		$ 38.5	

(1) The federal general tax reduction of 5% (2002 — 3%) is applicable to earnings that have not otherwise benefited from the manufacturing and processing tax credit and/or the resource allowance. Effective January 1, 2003, an additional federal tax reduction of 1% is applicable to earnings that have benefited from the resource allowance.

4. **Income taxes** (continued)

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

	2003	2002
Property, plant and equipment	**$215.5**	$239.1
Deferred assets and liabilities	**36.6**	24.5
Tax loss carryforwards	**(1.2)**	(0.8)
Income tax reassessment	**(12.9)**	(12.9)
Other	**0.5**	(2.3)
	238.5	247.6
Less: Amounts included in current future income taxes	**11.5**	16.8
	$227.0	$230.8

Unrecorded future income tax liabilities of the regulated operations amounted to $167.5 million at December 31, 2003. This balance includes $46.3 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

Expected future recoveries relating to tax loss carryforwards, which do not expire, have been recorded in the amount of $1.2 million. In addition, there are tax loss carryforwards of $0.7 million for which no tax benefit has been recorded. These losses begin to expire in 2007.

Income taxes paid amounted to $147.2 million (2002 – $277.1 million).

In 2001, Canadian Utilities received and paid an income tax reassessment of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. Management did not agree with this reassessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities. During 2003, Canadian Utilities was successful in appealing the reassessment to the Tax Court of Canada. However, the Federal Government has commenced an appeal of the Tax Court's decision with the Federal Court of Appeal. Consequently, the future income tax reduction of $12.9 million has not been adjusted.

5. **Direct charges to retained earnings**

	Three Months Ended December 31		Year Ended December 31	
	2003	2002	**2003**	2002
	(Unaudited)			
Issue costs of equity preferred shares (after income taxes)	**$ -**	$2.8	**$2.7**	$2.8
Purchase of Class A shares	**0.9**	-	**3.4**	-
	$0.9	$2.8	**$6.1**	$2.8

6. Property, plant and equipment

	2003			2002	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation
Utilities	3.6%	**$4,313.5**	**$1,618.2**	$4,098.3	$1,546.4
Power generation	3.4%	**2,694.2**	**784.4**	2,588.5	715.7
Logistics and energy services	3.8%	**1,069.7**	**381.3**	1,043.9	352.3
Other	16.0%	**67.4**	**36.9**	62.8	33.1
		$8,144.8	**2,820.8**	$7,793.5	2,647.5
Property, plant and equipment less accumulated depreciation			**5,324.0**		5,146.0
Unamortized contributions by utility customers for extensions to plant			**514.6**		489.0
			$4,809.4		$4,657.0

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $277.6 million (2002 – $259.4 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $265.8 million (2002 – $550.0 million) and non-depreciable assets of $39.3 million (2002 – $32.7 million).

7. Other assets

	2003	2002
Net accrued pension asset (Note 18)	**$ 52.5**	$ 48.0
Costs deferred for recovery through future regulated rates	**25.7**	27.6
Deferred costs related to disposition of retail energy businesses	**10.8**	8.5
Deferred financing charges	**27.9**	29.5
Deferred electricity costs	**-**	3.0
Other	**18.1**	17.2
	$135.0	$133.8

8. Credit lines

At December 31, 2003, Canadian Utilities has the following credit lines that enable it to obtain financing for general business purposes:

	2003			2002		
	Total	**Used**	**Available**	Total	Used	Available
Long term committed	**$ 350.0**	**$16.2**	**$ 333.8**	$ 350.0	$ 56.2	$ 293.8
Short term committed	**624.3**	**49.8**	**574.5**	627.7	52.9	574.8
Uncommitted	**178.5**	**14.1**	**164.4**	225.0	10.1	214.9
	$1,152.8	**$80.1**	**$1,072.7**	$1,202.7	$119.2	$1,083.5

9. Deferred electricity cost obligation

In December 2000, the Province of Alberta issued regulations providing for the deferral of price and volume variance in excess of forecast amounts in respect of the supply of electricity by distributors to their customers for the year ended December 31, 2000. In 2002, the AEUB issued decisions approving the collection by ATCO Electric of its deferred costs from customers, and permitting ATCO Electric to sell these deferred costs and related rights.

9. Deferred electricity cost obligation (continued)

In 2002, ATCO Electric sold deferred costs of $81 million to an unrelated purchaser for equivalent cash consideration. GAAP required that this transaction be accounted for as a financing arrangement rather than a sale. Accordingly, the cash received resulted in the recording of a deferred electricity cost obligation rather than a reduction of deferred electricity costs. The obligation bore interest at 3.3975%, which approximated the interest earned on the deferred costs. The obligation principal and interest incurred were paid to the purchaser as the deferred costs and interest earned were collected from customers. At December 31, 2003, the outstanding obligation was nil (2002 – $51.0 million).

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

Long term debt

	2003	2002
CU Inc. debentures – unsecured		
1993 Series 7.25% due September 2003	$ -	$ 60.0
1994 Series 8.73% due June 2004	**100.0**	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
2002 6.145% due November 2017	**150.0**	150.0
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
Canadian Utilities Limited debentures – unsecured		
2002 6.14% due November 2012	**100.0**	100.0
	1,775.0	1,835.0
ATCO Power Australia Pty Ltd. credit facility, at Bank Bill rates, due July 2004, payable in Australian dollars, unsecured (1)	**13.8**	21.4
ATCO Midstream Ltd. credit facility, at BA rates	**-**	8.0
ATCO Power Canada Ltd. credit facility, at BA rates, due March 2007, secured by a pledge of cash (1)	**12.0**	48.0
Other long term obligation, at 5.0%, due June 2005, unsecured	**4.5**	4.5
	$1,805.3	$1,916.9

On January 20, 2004, CU Inc. issued $180.0 million of 5.432% Debentures for cash.

Non-recourse long term debt

	2003	2002
Barking Power Limited project financing, payable in British pounds:		
At fixed rates averaging 7.95%, due to 2010	**$ 80.8**	$ 97.1
At LIBOR, due to 2010 (1)	**132.5**	159.2
Osborne Cogeneration Pty Ltd. project financing, payable in Australian dollars:		
At Bank Bill rates, due to 2013 (1)	**0.1**	2.6
At 6.825%, due to 2013 (1)	**51.6**	48.9

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

Non-recourse long term debt (continued)

	2003	2002
ATCO Power Alberta Limited Partnership ("APALP") project financing:		
At 7.29% to 2008, at LIBOR thereafter, due to 2016 [1]	**6.4**	7.7
At 7.067% to 2008, at LIBOR thereafter, due to 2016 [1]	**9.0**	10.8
At 7.25% to 2011, at LIBOR thereafter, due to 2016 [1]	**93.1**	95.6
Joffre project financing:		
At 6.435% to 2004, at BA rates thereafter, due to 2012 [1]	**2.3**	3.6
At 7.161%, due to 2012 [1]	**33.4**	35.6
At 8.59%, due to 2020	**32.0**	32.0
Scotford project financing:		
At 5.102%, due to 2008, at BA rates thereafter, due to 2014 [1]	**53.7**	-
At 5.102%, due to 2008, at LIBOR thereafter, due to 2014 [1]	**13.9**	-
At BA rates, due to 2014 [1]	**-**	54.7
At LIBOR, due to 2014 [1]	**-**	13.9
At 7.93%, due to 2022	**28.2**	28.4
Muskeg River project financing:		
At 5.147%, due 2007, at BA rates thereafter, due to 2014 [1]	**51.0**	53.1
At BA rates, due to 2014 [1]	**0.6**	-
At 7.56%, due to 2022	**34.9**	35.8
Brighton Beach project financing:		
At 5.325%, due to 2019 [1]	**40.7**	-
At 6.924%, due to 2024	**110.6**	110.6
Cory project financing:		
At BA rates, due to 2011 [1]	**0.1**	-
At 6.461%, due to 2011 [1]	**4.7**	4.8
At 7.586%, due to 2024	**38.8**	38.8
At 7.601%, due to 2026	**34.0**	34.0
	852.4	867.2
Less: Amounts due within one year	**46.3**	46.1
	$806.1	$821.1

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above interest rates have additional margin fees at a weighted average rate of 0.9% (2002 – 1.0%).

Canadian Utilities has fixed interest rates, either directly or through interest rate swap agreements, on 92% (2002 – 89%) of total long term debt and non-recourse long term debt.

The non-recourse long term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets and bank accounts at December 31, 2003 was $1,248.2 million (2002 – $1,203.8 million).

Guarantees

Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

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

a) **Equity contributions** – Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2003, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is anticipated to be $35.3 million.

b) **Completion of construction** – Represents completion guarantees associated with project financing whereby non-completion of a project by a certain date will require the repurchase of all or a portion of the project debt. At December 31, 2003, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is $161.2 million, with an expiry date of September 30, 2006.

c) **Project cash flows** – Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts ("MW") for the Scotford project and 48 MW for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2003, $0.4 million was payable for the Muskeg River and Scotford projects.

d) **Reserve amounts** – Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2003, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil (1)	$6.7
Joffre project financing	Nil (2)	$4.8
Muskeg River project financing	Nil (1)	$5.3
Scotford project financing	Nil (1)	$5.3

(1) No major maintenance reserve required for this financing.
(2) Reserve requirements of $1.4 million met with project cash flows.

e) **Prepaid operating and maintenance fee** – Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2003, the maximum value of the guarantee is $33.6 million.

f) **Purchase project assets** – Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

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

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:

- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2003, no such events have occurred.

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts. Canadian Utilities Limited has guaranteed ATCO Power's obligation to remediate certain deficiencies at the Oldman River project in the amount of $2.4 million. In addition, Canadian Utilities Limited has posted acceptable credit support in the amount of $2.2 million with respect to builders' liens filed against the Cory project.

ATCO Power (80%) and ATCO Resources (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects. The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Minimum debt repayments

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

	Long Term Debt	Non-Recourse Long term Debt	Total
2004	$113.8	$ 46.3	$160.1
2005	129.5	50.5	180.0
2006	175.0	68.0	243.0
2007	62.0	55.9	117.9
2008	100.0	81.0	181.0
	$580.3	$301.7	$882.0

Of the $160.1 million due in 2004, $113.8 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

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

Interest expense

Interest on debt is as follows:

	2003	2002
Long term debt	**$144.2**	$145.8
Non-recourse long term debt	**55.9**	49.8
Notes payable	**0.6**	0.6
Current bank indebtedness	**5.3**	8.5
Amortization of financing charges	**2.5**	2.2
Less: Capitalized on non-regulated projects	**(18.2)**	(22.8)
	$190.3	$184.1

Interest paid amounted to $207.8 million (2002 – $207.6 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 Canadian Utilities' current borrowing rate for similar borrowing arrangements.

	2003	2002
Long term debt		
Fixed rate	**$2,093.3**	$2,155.0
Floating rate	**25.8**	77.4
	$2,119.1	$2,232.4
Non-recourse long term debt		
Fixed rate	**$ 757.8**	$ 597.8
Floating rate	**133.5**	283.6
	$ 891.3	$ 881.4

11. Deferred credits

	2003	2002
Deferred availability incentives	**$ 43.3**	$45.0
Deferred electricity cost recoveries	**16.2**	-
Accrued equipment repairs and maintenance	**12.1**	13.1
Net accrued post employment benefits (Note 18)	**8.7**	6.0
Other	**26.1**	14.7
	$106.4	$78.8

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $7.5 million in 2003 (2002 – nil).

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, Canadian Utilities uses these estimates to forecast best case, worst case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

11. **Deferred credits** (continued)

Compared to the most likely scenario recorded in revenues, the best case scenario would have resulted in higher revenues of approximately $4.0 million, whereas the worst case scenario would have resulted in lower revenues of approximately $3.5 million.

12. Equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	**2003** Shares	**2003** Amount	2002 Shares	2002 Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	Open	**2,277,675**	**$ 56.9**	2,277,675	$ 56.9
5.3% Series R	$25.00	Open	**2,146,730**	**53.7**	2,146,730	53.7
6.6% Series S	$25.00	Open	**635,700**	**15.9**	635,700	15.9
5.8% Series W	$25.00	See below	**6,000,000**	**150.0**	6,000,000	150.0
6.0% Series X	$25.00	See below	**6,000,000**	**150.0**	-	-
Perpetual Cumulative Second Preferred Shares						
5.05% Series O	$25.00	December 2, 2006	**1,600,000**	**40.0**	1,600,000	40.0
5.05% Series T	$25.00	December 2, 2006	**1,600,000**	**40.0**	1,600,000	40.0
5.05% Series U	$25.00	December 2, 2006	**800,000**	**20.0**	800,000	20.0
5.25% Series V	$25.00	October 3, 2007	**4,400,000**	**110.0**	4,400,000	110.0
				$636.5		$486.5

On April 17, 2003, Canadian Utilities Limited issued $150.0 million Cumulative Redeemable Second Preferred Shares Series X for cash. The dividend rate has been fixed at 6.0%.

The dividends payable on the Perpetual Cumulative Second Preferred Shares Series O, T, U, and V are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between Canadian Utilities Limited and the owners of the shares.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $665.1 million (2002 – $472.9 million).

Redemption privileges

The preferred shares, except for Series W and X, are redeemable on the dates specified above at the option of Canadian Utilities Limited at the stated value plus accrued and unpaid dividends.

The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until March 1, 2012.

The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value plus a 4% premium for the next 12 months plus accrued and unpaid dividends. The redemption premium declines by 1% in each succeeding 12 month period until June 1, 2012.

13. Class A and Class B shares

Authorized and issued

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2001	39,876,769	$358.3	23,440,266	$148.4	63,317,035	$506.7
Stock options exercised	95,150	2.9	-	-	95,150	2.9
Converted: Class B to Class A	149,875	0.9	(149,875)	(0.9)	-	-
December 31, 2002	40,121,794	362.1	23,290,391	147.5	63,412,185	509.6
Purchased	(73,900)	(0.7)	-	-	(73,900)	(0.7)
Stock options exercised	45,350	1.6	-	-	45,350	1.6
Converted: Class B to Class A	1,040,465	6.6	(1,040,465)	(6.6)	-	-
December 31, 2003	**41,133,709**	**$369.6**	**22,249,926**	**$140.9**	**63,383,635**	**$510.5**

From January 1, 2004 to February 6, 2004, 29,750 Class A non-voting shares were issued with respect to the exercises of stock options.

Earnings per share

Earnings per Class A non-voting and Class B common share is calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share is calculated using the treasury stock method, which reflects the potential exercise of stock options on the weighted average Class A non-voting and Class B common shares outstanding. The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended December 31		Year Ended December 31	
	2003	2002	**2003**	2002
	(Unaudited)			
Weighted average shares outstanding	**63,371,535**	63,411,613	**63,389,192**	63,389,738
Effect of dilutive stock options	**310,985**	301,608	**275,855**	311,187
Weighted average diluted shares outstanding	**63,682,520**	63,713,221	**63,665,047**	63,700,925

Share owner rights

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

If a take-over bid is made for the Class B common shares which would result in the offeror owning more than 50% of the outstanding Class B common shares and which would constitute a change in control of Canadian Utilities Limited, owners of Class A non-voting shares are entitled, for the duration of the bid, to exchange their Class A non-voting shares for Class B common shares and to tender such Class B common shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A non-voting shares are entitled to exchange their shares for Class B common shares of Canadian Utilities Limited if ATCO Ltd., the present controlling share owner of Canadian Utilities Limited, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding

13. Class A and Class B shares (continued)

Class B common shares of Canadian Utilities Limited. In either case, each Class A non-voting share is exchangeable for one Class B common share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering. The complete text of the rights of exchange attached to the Class A non-voting shares is set out in a Certificate of Amendment dated September 10, 1982 issued to Canadian Utilities Limited pursuant to the Canada Business Corporations Act.

Normal course issuer bid

On May 20, 2002, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The offer expired on May 19, 2003. Over the life of the offer, 17,300 shares were purchased, all of which were purchased in 2003. On May 20, 2003, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The offer will expire on May 19, 2004. From May 20, 2003, to February 6, 2004, 56,600 shares have been purchased, all of which were purchased in 2003.

14. Stock based compensation plans

Stock option plan

Canadian Utilities Limited has a stock option plan under which 3,200,000 Class A non-voting shares are reserved for issuance in respect of options. Options may be granted to directors, officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on The Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

Changes in shares under option are summarized below:

	2003		2002	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**947,800**	**$37.15**	991,550	$35.72
Granted	**42,000**	**51.74**	52,500	51.51
Exercised	**(45,350)**	**35.60**	(95,150)	30.05
Settled	**-**	**-**	(1,100)	41.93
Options at end of year	**944,450**	**$37.88**	947,800	$37.15

Information about stock options outstanding at December 31, 2003 is summarized below:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Class A Shares	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Class A Shares	Weighted Average Exercise Price
$23.76 - $30.08	264,700	2.2	$27.27	264,700	$27.27
$34.46 - $37.74	295,450	5.9	35.65	238,850	35.62
$41.29 - $57.29	384,300	6.2	46.88	249,300	45.86
$23.76 - $57.29	944,450	5.0	$37.88	752,850	$36.08

In 2003, Canadian Utilities Limited granted 42,000 options to purchase Class A non-voting shares to officers and certain key employees at a weighted average exercise price of $51.74 per share. The options have a term of ten years and vest over the first five years.

14. Stock based compensation plans (continued)

Had Canadian Utilities adopted the fair value based method of accounting for stock options granted on and after January 1, 2002, earnings would have been reduced by $0.2 million (2002 – $0.1 million), but there would have been no effect on earnings per share. The reduction in earnings was determined using the Black-Scholes option pricing model, which estimated the weighted average value of the options granted during 2003 at $4.68 per option (2002 – $7.00 per option) using the following assumptions:

	2003	2002
Risk free interest rate	**4.3 %**	4.7 %
Expected holding period prior to exercise	**5.5 years**	5.7 years
Share price volatility	**12.1 %**	14.1 %
Estimated annual Class A share dividend	**4.0 %**	3.8 %

Share appreciation rights

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

Share appreciation rights expense amounted to $2.4 million (2002 – $0.9 million).

15. Changes in non-cash working capital

	2003	2002
Operating activities, changes related to:		
Accounts receivable	**$(92.0)**	$ (20.0)
Inventories	**(50.8)**	5.8
Deferred natural gas costs	**4.0**	(27.3)
Deferred electricity costs	**21.7**	6.7
Prepaid expenses	**(0.8)**	(10.5)
Accounts payable and accrued liabilities	**60.6**	(7.4)
Income taxes	**9.8**	(126.0)
Future income taxes	**(5.3)**	18.7
	$(52.8)	$(160.0)
Investing activities, changes related to:		
Inventories	**$ 0.5**	$ (2.0)
Prepaid expenses	**0.3**	2.0
Accounts payable and accrued liabilities	**(30.8)**	(8.3)
	$(30.0)	$ (8.3)
Financing activities, changes related to:		
Accounts receivable	**$ 7.9**	$ 7.7
Accounts payable and accrued liabilities	**-**	1.0
	$ 7.9	$ 8.7

16. Joint ventures

Canadian Utilities' interest in joint ventures is summarized below:

	2003	2002
Statement of earnings		
Revenues	**$ 420.9**	$ 378.1
Operating expenses	**291.7**	269.5
Depreciation and amortization	**34.7**	25.8
Interest	**34.5**	25.8
	60.0	57.0
Interest and other income	**5.7**	4.8
Earnings from joint ventures before income taxes	**$ 65.7**	$ 61.8
Balance sheet		
Current assets	**$ 143.1**	$ 160.2
Current liabilities	**(115.3)**	(112.7)
Property, plant and equipment	**997.5**	949.9
Deferred items – net	**(60.0)**	(83.3)
Non-recourse long term debt	**(612.6)**	(625.8)
Investment in joint ventures	**$ 352.7**	$ 288.3
Statement of cash flows		
Operating activities	**$ 80.7**	$ 55.3
Investing activities	**(105.6)**	(141.5)
Financing activities	**4.5**	74.4
Foreign currency translation	**(4.7)**	4.5
Decrease in cash position	**$ (25.1)**	$ (7.3)

Current assets include cash of $54.4 million (2002 — $76.6 million) which is only available for use within the joint ventures.

17. Related party transactions

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, Canadian Utilities sold fuel in the amount of $2.8 million (2002 — $3.2 million), recovered administrative expenses and business development costs totaling $3.0 million (2002 — $2.9 million) and incurred administrative expenses and corporate signature rights totaling $6.8 million (2002 — $6.6 million). Canadian Utilities also incurred advertising and promotion expenses from an entity related through common control totaling $1.1 million (2002 — $1.2 million). These transactions are in the normal course of business and under normal commercial terms.

18. Employee future benefits

Canadian Utilities 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.

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

Information about Canadian Utilities' benefit plans, in aggregate, is as follows:

	2003		2002	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan assets, obligations and funded status				
Market value of plan assets:				
Beginning of year	**$1,195.0**	**$ -**	$1,322.6	$ -
Actual return (loss) on plan assets	**159.1**	**-**	(94.9)	-
Employee contributions	**5.1**	**-**	5.2	-
Benefit payments	**(33.4)**	**-**	(34.2)	-
Payments to defined contribution plans	**(3.3)**	**-**	(3.7)	-
End of year	**$1,322.5**	**$ -**	$1,195.0	$ -
Accrued benefit obligations:				
Beginning of year	**$ 952.0**	**$ 47.9**	$ 884.8	$ 44.8
Current service cost	**20.9**	**1.9**	17.6	1.3
Interest cost	**65.3**	**3.8**	59.4	3.0
Employee contributions	**5.1**	**-**	5.2	-
Benefit payments from plan assets [1]	**(33.4)**	**-**	(34.2)	-
Benefit payments by employer	**(3.6)**	**(1.7)**	(1.6)	(1.8)
Experience losses [2]	**86.3**	**10.6**	20.8	0.6
End of year	**$1,092.6**	**$ 62.5**	$ 952.0	$ 47.9
Funded status:				
Excess (deficiency) of assets over obligations	**$ 229.9**	**$(62.5)**	$ 243.0	$(47.9)
Amounts not yet recognized in financial statements:				
Unrecognized net experience losses	**270.1**	**13.6**	265.4	3.4
Unrecognized net transitional liability (asset)	**(319.0)**	**27.6**	(351.8)	29.9
Accrued asset (liability)	**181.0**	**(21.3)**	156.6	(14.6)
Regulatory asset (liability) [3]	**(128.5)**	**12.6**	(108.6)	8.6
Net accrued asset (liability) recognized (Notes 7, 11)	**$ 52.5**	**$ (8.7)**	$ 48.0	$ (6.0)

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

(2) Changes in liability discount rate and long term inflation rate assumptions resulted in experience losses in 2003 of approximately $69.0 million for the pension benefit plans and $2.0 million for the other post employment benefit plans.

(3) The regulatory asset (liability) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

18. Employee future benefits (continued)

	2003		2002	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan expense (income)				
Components of benefit plan expense (income):				
Current service cost	**$ 20.9**	**$1.9**	$ 17.6	$1.3
Interest cost	**65.3**	**3.8**	59.4	3.0
Expected return on plan assets	**(91.0)**	**-**	(99.5)	-
Amortization of net experience losses	**13.5**	**0.4**	-	-
Amortization of net transitional liability (asset)	**(32.8)**	**2.3**	(30.9)	2.3
Defined benefit plans expense (income)	**(24.1)**	**8.4**	(53.4)	6.6
Defined contribution plans expense	**4.5**	**-**	5.5	-
Total expense (income)	**(19.6)**	**8.4**	(47.9)	6.6
Less: Capitalized	**1.0**	**2.0**	0.6	1.5
Less: Unrecognized defined benefit plans expense (income) [1]	**(19.5)**	**2.5**	(41.3)	1.5
Net expense (income) recognized	**$ (1.1)**	**$3.9**	$ (7.2)	$3.6

[1] The unrecognized defined benefit plans expense (income) reflects an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

Weighted average assumptions

	2003		2002	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan expense (income):				
Expected long term rate of return on plan assets for the year	**7.5%**	**-**	8.0%	-
Interest rate for the year	**6.5%**	**6.5%**	6.9%	6.9%
Average compensation increase for the year	**2.75%**	**-**	3.0%	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**6.25%**	**6.25%**	6.5%	6.5%
Long term inflation rate	**2.5%**	(1)	2.25%	(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, 10.5% for 2003 grading down over 10 years to 4.5% (2002 – 8.85% for 2002 grading down over 5 years to 4.0%), and, for other medical and dental costs, 4.0% for 2003 and thereafter (2002 – 3.5% for 2002 and thereafter).

18. Employee future benefits (continued)

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan expense (income) for 2003 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2003 Pension Benefit Plans		2003 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Expense (Income)	Accrued Benefit Obligation	Benefit Plan Expense (Income)
Expected long term rate of return on plan assets				
1% increase [1]		$(3.5)		
1% decrease [1]		$ 3.5		
Liability discount rate				
1% increase [1]	$(52.2)	$(0.3)	$(2.8)	$(0.3)
1% decrease [1]	$ 52.2	$ 0.3	$ 2.8	$ 0.3
Long term inflation rate [2]				
1% increase [1]	$ 34.6	$ 0.5	$ 2.6	$ 0.5
1% decrease [1]	$(34.6)	$(0.5)	$(2.2)	$(0.4)

(1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans expense (income), which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.

(2) The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

Pension benefit plan assets

	2003		2002	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [1]	**$ 817.3**	**61.8**	$ 723.6	60.6
Fixed income securities [2]	**442.4**	**33.4**	403.8	33.8
Real estate [3]	**31.1**	**2.4**	36.2	3.0
Cash and other assets [4]	**31.7**	**2.4**	31.4	2.6
	$1,322.5	**100.0**	$1,195.0	100.0

(1) Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2003, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $134.4 million and $148.7 million, respectively (2002 – $137.4 million and $133.7 million, respectively).

(2) Fixed income securities consist of investments in federal and provincial government and corporate bonds and debentures.

(3) Real estate consists of investments in closed-end real estate funds.

(4) Cash and other assets consist of cash, short term notes and money market funds.

18. Employee future benefits (continued)

At December 31, 2003, plan assets include long term debt of CU Inc. having a market value of $1.8 million (2002 – $1.7 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $11.6 million (2002 – $10.3 million) and Class I Non-Voting shares of ATCO Ltd. having a market value of $8.7 million (2002 – $7.8 million).

Funding

Employees are required to contribute a percentage of their salary to the defined benefit pension plans. Canadian Utilities 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, Canadian Utilities 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.

Included in the accrued benefit obligations are certain supplementary defined benefit pension plans that are paid by Canadian Utilities out of general revenues. These supplementary plans had accrued benefit obligations of $70.9 million at December 31, 2003 (2002 – $58.7 million).

19. Risk management and financial instruments

Canadian Utilities is exposed to changes in interest rates, commodity prices and foreign currency exchange rates. The Power Generation segment is affected by the cost of natural gas and the price of electricity in the Province of Alberta and the Logistics and Energy Services segment is affected by the cost of natural gas and the price of natural gas liquids. In conducting its business, Canadian Utilities 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.

Interest rate risk

Long term debt and non-recourse long term debt have variable interest rates that have been hedged through the following interest rate swap agreements:

Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Completion Date	Principal/Face Value 2003	2002
6.435%	90 day BA	December 2004	**$ 2.3**	$ 3.6
5.147%	90 day BA	December 2007	**51.0**	53.1
5.102%	90 day BA	September 2008	**67.6**	-
7.290%	90 day BA	November 2008	**6.4**	7.7
7.067%	90 day BA	December 2008	**9.0**	10.8
6.461%	90 day BA	June 2011	**4.7**	4.8
7.250%	6 month LIBOR	December 2011	**93.1**	95.6
7.161%	90 day BA	September 2012	**34.3**	35.6
6.825%	Bank Bill Rate in Australia	June 2013	**51.6**	48.9
6.575%	90 day BA	March 2019	**40.7**	9.2
			$360.7	$269.3

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) The above swap fixed interest rates include any long term debt margin fees (Note 10).

19. Risk management and financial instruments (continued)

Foreign exchange rate risk

Canadian Utilities has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates.

Canadian Utilities has entered into foreign exchange forward contracts in order to fix the exchange rate on certain planned equipment expenditures denominated in U.S. dollars and operational cash flows denominated in EUROs. At December 31, 2003, the contracts consist of purchases of $0.5 million U.S. (2002 – $3.1 million U.S.), and there were no contracts outstanding to sell U.S. dollars (2002 – $0.4 million U.S) or to purchase EUROs (2002 – 4.1 million EUROs).

Energy commodity price risk

As a result of an AEUB approved storage plan related to the Carbon storage facility, Canadian Utilities has entered into certain energy contracts to fix the price of natural gas for the customers of the Utilities segment. All associated costs and benefits of these contracts are passed to customers through regulated rates, and accordingly, Canadian Utilities does not bear any risk for price fluctuations provided that the contracts are in accordance with the storage plan. At December 31, 2003, the contracts consist of natural gas sales of 151 terajoules ("TJ") for $1.0 million (2002 – 3,774.4 TJ for $22.4 million) and natural gas purchases of 151 TJ for $1.0 million (2002 – nil).

Fair values

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

	2003			2002		
	Notional Principal	**Fair Value (Payable) Receivable**	**Maturity**	Notional Principal	Fair Value (Payable) Receivable	Maturity
Interest rate swaps	**$360.6**	**$(14.0)**	**2004-2019**	$269.8	$(14.0)	2004 - 2019
Foreign exchange forward contracts	**$ 0.7**	**Nil**	**2004**	$ 11.3	$ 1.0	2003

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.

20. Commitments and contingencies

Commitments

Canadian Utilities 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:

2004	2005	2006	2007	2008	Total of All Subsequent Years
$12.8	$11.9	$11.2	$10.5	$10.1	$15.1

20. Commitments and contingencies (continued)

Contingencies

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

21. Regulatory matters

The AEUB issued decisions regarding ATCO Gas', ATCO Electric's and ATCO Pipelines' general rate applications on October 1, 2003, October 2, 2003, and December 2, 2003, respectively. These decisions approved, among other things, for ATCO Electric, a rate of return on common equity of 9.4% and a common equity ratio of 32% for transmission operations and 35% for distribution operations for 2003, for ATCO Gas, a rate of return on common equity of 9.5% and a common equity ratio of 37% for 2003 and 2004 and, for ATCO Pipelines, a rate of return on common equity of 9.5% and a common equity ratio of 43.5% for 2003.

ATCO Electric's and ATCO Pipelines' 2004 rate of return on common equity and the common equity ratios for the transmission and distribution operations will be determined as part of a generic cost of capital hearing which commenced in November 2003.

The companies, as directed by the AEUB, have refiled the 2003 and 2004 general rate applications incorporating the findings in the decisions. In a decision dated February 17, 2004, the AEUB issued its final determination of the revenue requirements for ATCO Electric for the 2003 and 2004 test years, accepting the refiling with no material changes. The AEUB has not yet issued its determination of the revenue requirements for ATCO Gas and ATCO Pipelines for the 2003 and 2004 test years following the refilings. It is expected that such determination will not have a material effect on the accounts of Canadian Utilities.

Canadian Utilities 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.

22. Segmented information

Description of segments

Canadian Utilities operates in the following business segments:

The Utilities Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated engineering, procurement and construction services for customers in the utility, energy and telecommunications sectors by ATCO Utility Services.

The Power Generation Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity of Alberta Power (2000).

The Logistics and Energy Services Business Group includes the regulated transportation of natural gas by ATCO Pipelines, the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream and the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec.

The Technologies Business Group and Other Businesses includes the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel. In addition, Canadian Utilities owns commercial real estate in Fort McMurray, Alberta.

22. **Segmented information** (continued)

Segmented results – Three months ended December 31

2003 2002	Utilities	Power Generation	Logistics & Energy Services	Technologies & Other Businesses	Corporate	Intersegment Eliminations	Consolidated
(Unaudited)							
Revenues – external	**$ 632.5** $ 603.3	**$ 171.9** $ 165.8	**$ 142.6** $ 156.9	**$ 3.1** $ 4.5	**$ 0.2** $ 0.2	**$ -** $ -	**$ 950.3** $ 930.7
Revenues – intersegment [(1)]	**15.3** 23.8	**-** -	**172.9** 107.4	**31.1** 21.5	**2.6** 2.6	**(221.9)** (155.3)	**-** -
Revenues	**$ 647.8** $ 627.1	**$ 171.9** $ 165.8	**$ 315.5** $ 264.3	**$ 34.2** $ 26.0	**$ 2.8** $ 2.8	**$(221.9)** $(155.3)	**$ 950.3** $ 930.7
Earnings attributable to Class A and Class B shares	**$ 36.2** $ 26.8	**$ 35.7** $ 23.4	**$ 14.3** $ 19.4	**$ 5.1** $ 2.8	**$ (4.9)** $ (0.7)	**$ 0.3** $ 1.8	**$ 86.7** $ 73.5

Segmented results – Year ended December 31

2003 2002	Utilities	Power Generation	Logistics & Energy Services	Technologies & Other Businesses	Corporate	Intersegment Eliminations	Consolidated
Revenues – external	**$2,409.8** $1,781.1	**$ 643.4** $ 584.6	**$ 668.6** $ 597.9	**$ 20.6** $ 12.1	**$ 0.2** $ 0.2	**$ -** $ -	**$3,742.6** $2,975.9
Revenues – intersegment [(1)]	**68.4** 86.1	**-** -	**594.8** 335.8	**106.2** 89.8	**11.2** 10.9	**(780.6)** (522.6)	**-** -
Revenues	**2,478.2** 1,867.2	**643.4** 584.6	**1,263.4** 933.7	**126.8** 101.9	**11.4** 11.1	**(780.6)** (522.6)	**3,742.6** 2,975.9
Operating expenses	**2,084.4** 1,516.7	**351.9** 336.0	**1,119.0** 765.7	**86.2** 74.9	**13.8** 11.8	**(786.6)** (534.6)	**2,868.7** 2,170.5
Depreciation and amortization	**138.6** 126.8	**78.3** 68.2	**41.6** 42.1	**9.9** 7.3	**0.5** 0.4	**-** (0.4)	**268.9** 244.4
Interest expense	**93.6** 96.3	**75.2** 68.4	**22.3** 24.6	**0.8** 0.8	**145.6** 144.1	**(147.2)** (150.1)	**190.3** 184.1
Gain on sale of Viking-Kinsella property	**-** (110.1)	**-** -	**-** -	**-** -	**-** -	**-** -	**-** (110.1)
Interest and other income	**(7.4)** (11.0)	**(7.5)** (8.5)	**(6.9)** (5.1)	**(0.4)** (0.1)	**(158.4)** (151.5)	**147.2** 150.1	**(33.4)** (26.1)
Earnings before income taxes	**169.0** 248.5	**145.5** 120.5	**87.4** 106.4	**30.3** 19.0	**9.9** 6.3	**6.0** 12.4	**448.1** 513.1
Income taxes	**62.6** 92.4	**49.3** 41.8	**24.8** 40.3	**11.2** 7.9	**5.7** 3.2	**2.1** 4.3	**155.7** 189.9
	106.4 156.1	**96.2** 78.7	**62.6** 66.1	**19.1** 11.1	**4.2** 3.1	**3.9** 8.1	**292.4** 323.2
Dividends on equity preferred shares	**8.7** 8.4	**3.5** 3.4	**1.8** 1.7	**-** -	**19.1** 4.7	**-** -	**33.1** 18.2
Earnings attributable to Class A and Class B shares	**$ 97.7** $ 147.7	**$ 92.7** $ 75.3	**$ 60.8** $ 64.4	**$ 19.1** $ 11.1	**$ (14.9)** $ (1.6)	**$ 3.9** $ 8.1	**$ 259.3** $ 305.0
Total assets	**$2,850.0** $2,630.9	**$2,191.0** $2,174.7	**$ 837.9** $ 806.1	**$ 55.2** $ 47.4	**$ 184.8** $ 302.1	**$ (48.4)** $ (26.8)	**$6,070.5** $5,934.4
Purchase of property, plant and equipment	**$ 314.3** $ 274.5	**$ 131.7** $ 236.0	**$ 37.5** $ 48.9	**$ 11.6** $ 10.0	**$ 0.6** $ 0.4	**$ -** $ -	**$ 495.7** $ 569.8

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

22. **Segmented information** (continued)

Geographic segments

	Domestic		Foreign		Consolidated	
	2003	2002	**2003**	2002	**2003**	2002
Revenues	**$3,234.3**	$2,699.4	**$238.3**	$276.5	**$3,742.6**	$2,975.9
Property, plant and equipment	**$4,436.7**	$4,250.0	**$372.7**	$407.0	**$4,809.4**	$4,657.0

23. Sale of Retail operations

In December 2002, Direct Energy Marketing Limited ("Direct Energy") agreed to purchase the retail energy businesses of ATCO Gas and ATCO Electric, subject to the satisfaction of certain conditions, including the receipt of required regulatory approvals and the government of Alberta amending certain natural gas and electricity legislation.

In December 2003, the AEUB issued decisions approving the transfer of the retail operations of ATCO Gas and ATCO Electric to Direct Energy, appointing Direct Energy provider of the natural gas Default Rate Tariff and electricity Regulated Rate Tariff in the ATCO Gas and ATCO Electric service territories and approving the tariff rate structure of Direct Energy Regulated Services, ATCO Gas and ATCO Electric. The City of Calgary has filed leave to appeal the AEUB decision approving the transfer of the retail operations. Canadian Utilities is reviewing the AEUB decisions and certain other conditions which must be satisfied in order to close the sale of its retail business to Direct Energy.

If the sale does close on the anticipated terms, ATCO Gas and ATCO Electric will no longer be involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return. The sale does not include any of the distribution and transmission facilities used to deliver natural gas and electricity to customers.

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED
An ATCO Company

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

FOR THE YEAR ENDED DECEMBER 31, 2003

CANADIAN UTILITIES LIMITED

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

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's unaudited comparative interim financial statements for the three months ended December 31, 2003, and the audited comparative financial statements for the year ended December 31, 2003. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

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

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

FORWARD-LOOKING INFORMATION

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

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

BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from four Business Groups: Utilities, Power Generation, Logistics and Energy Services, and Technologies. For the purposes of financial disclosure, the Technologies Business Group is included in Technologies and Other Businesses and corporate transactions are accounted for as Corporate (see Note 22 to the comparative financial statements). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

The Utilities Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated engineering, procurement and construction services for customers in the utility, energy and telecommunications sectors by ATCO Utility Services.

The Power Generation Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity by Alberta Power (2000).

The Logistics and Energy Services Business Group includes the regulated transportation of natural gas by ATCO Pipelines, the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, and the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec.

The Technologies Business Group and Other Businesses includes the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal-fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel. In addition, the Corporation owns commercial real estate in Fort McMurray, Alberta.

SELECTED ANNUAL AND QUARTERLY INFORMATION

($ Millions except per share data)

	For the Three Months Ended				Year Ended
	Mar	**Jun**	**Sep**	**Dec**	**Dec 31**
		(unaudited)			
Revenues:					
2003	1,372.2	797.5	622.6	950.3	3,742.6
2002	858.1	644.4	542.7	930.7	2,975.9
2001					3,513.6
Earnings attributable to Class A and Class B shares (1):					
2003	85.8	43.4	43.4	86.7	259.3
2002 (2)	144.2	42.9	44.4	73.5	305.0
2001					237.1
Earnings per Class A and Class B share (1):					
2003	1.35	0.69	0.68	1.37	4.09
2002	2.28	0.67	0.70	1.16	4.81
2001					3.74
Diluted earnings per Class A and Class B share (1):					
2003	1.34	0.69	0.68	1.36	4.07
2002	2.27	0.67	0.70	1.15	4.79
2001					3.72

Notes:

(1) *There were no discontinued operations or extraordinary items during these periods.*

(2) *The earnings for the three months ended March 31 and December 31 include earnings of $66.7 million and $0.6 million, respectively, on the sale of the Viking-Kinsella natural gas producing property.*

(3) *Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.*

(4) *The above data has been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.*

	Year Ended December 31		
	2003	2002	2001
	($ Millions except per share data)		
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O (1)	1.26	1.26	1.14
Series Q	1.48	1.48	1.48
Series R	1.33	1.33	1.33
Series S	1.65	1.65	1.65
Series T (2)	1.26	1.26	1.16
Series U (2)	1.26	1.26	1.16
Series V (3)	1.31	1.17	1.17
Series W (4)	1.44	-	-
Series X (5)	0.93	-	-
Class A and Class B shares	2.04	1.96	1.88
Total assets	6,070.5	5,934.4	5,404.0
Long term debt	1,805.3	1,916.9	1,855.9
Non-recourse long term debt	806.1	821.1	673.8
Equity preferred shares	636.5	486.5	336.5
Class A and Class B share owners' equity	1,951.6	1,830.1	1,643.8

Notes:

(1) The dividend was reset to $1.26 (5.05%) for the period between December 1, 2001 and December 1, 2006.
(2) The dividend was reset to $1.26 (5.05%) for the period between December 2, 2001 and December 2, 2006.
(3) The dividend was reset to $1.31 (5.25%) for the period between October 3, 2002 and October 3, 2007.
(4) Issued December 3, 2002.
(5) Issued April 17, 2003.
(6) The above data has been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

The principal factors that have caused variations in quarterly revenues have been fluctuations in temperatures, changes in natural gas and electricity prices and the timing of rate decisions. In the case of earnings, the principal factors have been the sale of the Viking-Kinsella natural gas producing property (the "Viking property") in the first quarter of 2002, changes in electricity prices in Alberta, fluctuations in temperatures and the timing of rate decisions.

RESULTS OF OPERATIONS

Consolidated Operations

Revenues for the three months ended December 31, 2003, increased by $19.6 million to $950.3 million, primarily due to the higher price of natural gas purchased for customers on a "no-margin" basis, colder temperatures, the impact of the Alberta Energy and Utilities Board ("AEUB") decision respecting the 2003/2004 general rate application of ATCO Gas (the "2003/2004 rate decision for ATCO Gas"), and increased business activity in the Power Generation Business Group and ATCO Midstream, partially offset by the impact of the AEUB decision respecting the 2003/2004 general tariff application of ATCO Electric (the "2003/2004 rate decision for ATCO Electric"), the impact of the AEUB decision respecting the 2003/2004 general rate application of ATCO Pipelines (the "2003/2004 rate decision for ATCO Pipelines") and lower revenues from ATCO Frontec projects. Temperatures for the three months ended December 31, 2003, were 3.2% warmer than normal, compared to 11.4% warmer than normal for the corresponding period in 2002.

Revenues for the year ended December 31, 2003, increased by $766.7 million to $3,742.6 million, primarily due to the higher price of natural gas and electricity purchased for customers on a "no-margin" basis by ATCO Gas and ATCO Electric, higher natural gas prices on gas sales by ATCO Midstream, and increased business activity in all subsidiaries except ATCO Pipelines and ATCO Frontec. The impact of warmer temperatures in ATCO Gas, reduced earnings from the Barking generating plant in the United Kingdom, and the impact of the 2003/2004 rate decision for ATCO Pipelines partially offset the increased revenues. Temperatures in 2003 were 3.4% colder than normal, whereas temperatures in 2002 were 6.3% colder than normal.

Earnings attributable to Class A shares and Class B shares for the three months ended December 31, 2003, increased by $13.2 million ($0.21 per share) to $86.7 million ($1.37 per share), primarily due to the impact of the 2003/2004 rate decision for ATCO Gas, stronger operational results in Alberta Power (2000) and the Technologies Business Group, colder temperatures in ATCO Gas and a favourable tax adjustment in Australia for ATCO Power ($8.9 million), partially offset by the impact of the 2003/2004 rate decisions for ATCO Pipelines and ATCO Electric, and the carrying costs, net of investment income, in respect of the $400.0 million of preferred shares and debentures issued between November 2002 and April 2003 that reduced earnings by $3.5 million.

Earnings attributable to Class A and Class B shares for the year ended December 31, 2003, increased by $21.6 million ($0.34 per share) to $259.3 million ($4.09 per share), excluding the impact of the sale of the Viking property. Earnings for 2002 were $237.7 million, excluding the after-tax gain of $67.3 million on the sale of the Viking property. 2002 earnings in total were $305 million.

This increase was primarily due to stronger operational results in all subsidiaries except ATCO Pipelines and ATCO Frontec, and a favourable tax adjustment in Australia for ATCO Power ($8.9 million). These increases more than offset the carrying costs, net of investment income, in respect of the $400.0 million of preferred shares and debentures issued between November 2002 and April 2003 that reduced earnings by $13.0 million in 2003. These preferred shares and debentures were issued during a low interest rate environment to strengthen the Corporation's balance sheet and allow for future growth.

Return on common equity was 13.7% in 2003.

Operating expenses (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended December 31, 2003, increased by $10.8 million to $714.7 million, largely due to higher natural gas supply costs and higher selling and administrative expenses associated with the impact of the 2003/2004 rate decision for ATCO Gas, increased bad debts expense in ATCO Gas and higher share appreciation rights expense, partially offset by lower purchased power costs.

Operating expenses for the year ended December 31, 2003, increased by $698.2 million to $2,868.7 million, primarily due to higher natural gas and purchased power costs and higher operation and maintenance expenses associated with increased business activity in all subsidiaries except ATCO Pipelines and ATCO Frontec.

Depreciation and amortization expenses for the three months ended December 31, 2003, increased by $4.8 million to $72.7 million, primarily due to capital additions in 2003 and 2002.

Depreciation and amortization expenses for the year ended December 31, 2003, increased by $24.5 million to $268.9 million, primarily due to capital additions in 2003 and 2002, partially offset by depreciation adjustments associated with the sale of the Viking property in 2002.

Interest expense for the three months ended December 31, 2003, increased by $1.8 million to $47.1 million, primarily due to interest on non-recourse financings for the new Cory, Muskeg River, Oldman River and Scotford generating plants commissioned by ATCO Power in 2003 (the "New ATCO Power Generating Plants").

Interest expense for the year ended December 31, 2003, increased by $6.2 million to $190.3 million, primarily due to interest on non-recourse financing for the New ATCO Power Generating Plants, partially offset by lower interest rates associated with higher cost long term debt refinanced in 2002 and 2003. Interest capitalized on non-regulated projects for the year ended December 31, 2003, decreased by $4.6 million to $18.2 million.

In 2002, the Corporation sold its Viking property, which had a net book value of approximately $40 million, for $550 million. In accordance with an AEUB decision, $385.0 million plus related adjustments for future abandonment and future income taxes of $20.6 million, for a total of $405.6 million, was distributed to customers by way of lump sum payments. The Corporation's share of the net proceeds was $150.5 million, after adjustments, resulting in a gain of $110.1 million before income taxes of $42.8 million. This sale increased earnings by $67.3 million.

Interest and other income for the three months ended December 31, 2003, increased by $1.7 million to $9.5 million, primarily due to interest income on higher cash balances.

Interest and other income for the year ended December 31, 2003, increased by $7.3 million to $33.4 million, primarily due to interest income on higher cash balances.

Income taxes for the three months ended December 31, 2003, decreased by $14.6 million to $29.7 million, largely due to lower income tax rates, ATCO Power's favourable tax adjustment in Australia and a change in income tax methodology arising from the 2003/2004 rate decision for ATCO Pipelines, partially offset by higher earnings.

Income taxes for the year ended December 31, 2003, excluding the $42.8 million of income taxes on the sale of the Viking property in 2002, increased by $8.6 million to $155.7 million. This increase was primarily due to higher earnings and the impact of a 2002 refund to customers of amounts previously recovered from customers for future income taxes related to the Viking property. This increase was partially offset by lower income tax rates, ATCO Power's favourable tax adjustment in Australia, and a change in income tax methodology arising from the 2003/2004 rate decision for ATCO Pipelines. Income taxes for 2002, including the impact of the sale of the Viking property, were $189.9 million.

Dividends on equity preferred shares for the three months increased by $3.7 million to $8.9 million, primarily due to the issue of $150.0 million of 5.80% Cumulative Redeemable Second Preferred Shares Series W ("Series W Preferred Shares") on December 3, 2002, and $150.0 million of 6.00% Cumulative Redeemable Second Preferred Shares Series X ("Series X Preferred Shares") on April 17, 2003.

Dividends on equity preferred shares for the year ended December 31, 2003, increased by $14.9 million to $33.1 million, primarily due to the issue of the Series W Preferred Shares and the Series X Preferred Shares.

Segmented revenues for the three months and for the year ended December 31, 2003, were as follows:

Business Groups	**Three Months Ended December 31**		**Year Ended December 31**	
($ Millions)	**2003**	2002	**2003**	2002
	(unaudited)			
Utilities	**647.8**	627.1	**2,478.2**	1,867.2
Power Generation	**171.9**	165.8	**643.4**	584.6
Logistics and Energy Services	**315.5**	264.3	**1,263.4**	933.7
Technologies and Other Businesses	**34.2**	26.0	**126.8**	101.9
Corporate	**2.8**	2.8	**11.4**	11.1
Intersegment eliminations	**(221.9)**	(155.3)	**(780.6)**	(522.6)
Total	**950.3**	930.7	**3,742.6**	2,975.9

Segmented earnings attributable to Class A and Class B shares for the three months and for the year ended December 31, 2003, were as follows:

Business Groups	Three Months Ended December 31		Year Ended December 31	
($ Millions)	**2003**	2002	**2003**	2002
	(unaudited)			
Utilities (1)	**36.2**	26.8	**97.7**	147.7
Power Generation	**35.7**	23.4	**92.7**	75.3
Logistics and Energy Services	**14.3**	19.4	**60.8**	64.4
Technologies and Other Businesses	**5.1**	2.8	**19.1**	11.1
Corporate	**(4.9)**	(0.7)	**(14.9)**	(1.6)
Intersegment eliminations	**0.3**	1.8	**3.9**	8.1
Total	**86.7**	73.5	**259.3**	305.0

Note:

(1) The earnings for the three months ended December 31, 2002, and for the year ended December 31, 2002, include earnings of $0.6 million and $67.3 million, respectively, on the sale of the Viking property.

Utilities

Revenues from the Utilities Business Group for the three months ended December 31, 2003, increased by $20.7 million to $647.8 million, primarily due to higher revenues in ATCO Gas, resulting from higher prices of natural gas purchased for customers on a "no-margin" basis, colder temperatures, the impact of the 2003/2004 rate decision for ATCO Gas and customer additions. This increase was partially offset by the impact of the 2003/2004 rate decision for ATCO Electric. Temperatures for the three months ended December 31, 2003, were 3.2% warmer than normal, compared to 11.4% warmer than normal for the corresponding period in 2002.

Revenues for the year ended December 31, 2003, increased by $611.0 million to $2,478.2 million, primarily due to higher revenues in ATCO Gas, resulting from higher prices for natural gas purchased for customers on a "no-margin" basis, higher sales and the impact of the 2003/2004 rate decision for ATCO Gas, and higher prices for electricity purchased for customers on a "no-margin" basis in ATCO Electric. This increase was partially offset by the impact of the 2003/2004 rate decision for ATCO Electric and the impact of warmer temperatures in ATCO Gas. Temperatures in 2003 were 3.4% colder than normal, whereas temperatures in 2002 were 6.3% colder than normal.

Earnings for the three months ended December 31, 2003, increased by $9.4 million to $36.2 million, primarily the result of improved operating results in ATCO Electric, stronger performance in ATCO Gas as a result of the impact of the 2003/2004 rate decision for ATCO Gas, colder temperatures and customer additions, and the impact in 2002 of the AEUB decisions regarding affiliated party transactions and the Carbon natural gas storage facility. This increase was partially offset by higher operation and maintenance costs, and the impact of the 2003/2004 rate decision for ATCO Electric.

Earnings for the year ended December 31, 2003, increased by $17.3 million to $97.7 million, excluding the $67.3 million in earnings on the sale of the Viking property in 2002. This increase was primarily the result of improved operating results and growth in ATCO Electric, stronger performance in ATCO Gas as a result of the impact of the 2003/2004 rate decision for ATCO Gas and customer additions, and the impact in 2002 of the AEUB decisions regarding affiliated party transactions and the Carbon natural gas storage facility. This increase was partially offset by the impact of the 2003/2004 rate decision for ATCO Electric, higher operating costs, and the impact of warmer temperatures in ATCO Gas. Earnings for 2002, including the impact of the sale of the Viking property, were $147.7 million. The $97.7 million of earnings amounted to 37.7% of consolidated earnings of the Corporation.

Operating expenses for the year ended December 31, 2003, increased by $567.7 million to $2,084.4 million, primarily due to higher natural gas supply and purchased power costs. Natural gas supply and purchased power costs are recovered in customer rates. Natural gas supply costs are based on the forecast cost of natural gas included in customer rates. Variances from forecast costs are deferred until such time as approval from the AEUB is obtained for refund to or collection from customers and revenues and natural gas supply costs are adjusted accordingly.

Purchased power costs are based on the actual cost of electricity purchased, whereas the amount included in customer rates 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 AEUB is obtained for refund to or collection from customers. As a consequence, changes in natural gas supply and purchased power costs have no effect on the Corporation's earnings. ATCO Gas' customers have been billed on a monthly flow-through basis since April 1, 2002. ATCO Electric's customers have been billed on a monthly flow-through of market prices for electric energy since April 1, 2003. The "flow-through" rate is based on the actual spot market price for the energy that customers use during each billing period.

In the first quarter of 2003, ATCO Gas commenced the first phase of a $278 million project to relocate natural gas meters currently inside homes to the outside. The project will make the distribution system safer by relocating and replacing aging infrastructure, improve metering accuracy and accessibility, and facilitate more efficient meter reading. The 2003/2004 rate decision for ATCO Gas approved a program which will result in meters with underground entries being relocated over 10 years and all other inside meters moved as part of the existing meter recall program. The decision also allows ATCO Gas to move meters at any time if they are deemed unsafe.

Included in ATCO Gas' deferred gas account balance is an amount representing the difference between the amount of natural gas "transportation" customers put onto ATCO Gas' and ATCO Pipelines' pipeline systems and the amount of natural gas these same customers remove from the system. This amount is referred to as a "transportation imbalance". In addition, the deferred gas cost account includes an amount representing the difference between all purchases of natural gas and sales of natural gas to ATCO Gas customers.

The AEUB has approved the inclusion of the transportation imbalances in the deferred gas account. Adjustments arising out of a monthly reconciliation of this account are collected from or reimbursed to customers.

ATCO Gas and ATCO Pipelines have been working together to confirm the accuracy of the historical transportation imbalances. It is anticipated that this process will be completed during the first quarter of 2004, at which time an application may be made to the AEUB to address any required adjustments to the deferred gas cost account.

Power Generation

Revenues from the Power Generation Business Group for the three months ended December 31, 2003, increased by $6.1 million to $171.9 million, primarily due to the commissioning of the New ATCO Power Generating Plants and higher capacity and energy charges and improved operating results in Alberta Power (2000). Prices for electricity sold to the Alberta Electric System Operator ("AESO"), formerly the Alberta Power Pool, for the three months ended December 31, 2003, averaged $54.71, compared to average prices of $61.58 for the corresponding period in 2002. Natural gas prices for the three months ended December 31, 2003, averaged $5.50 per gigajoule, compared to average prices of $5.37 for the corresponding period in 2002.

Revenues for the year ended December 31, 2003, increased by $58.8 million to $643.4 million, primarily due to higher prices received for electricity sold to the AESO, the commissioning of the New ATCO Power Generating Plants, and higher capacity and energy charges and improved operating results in Alberta Power (2000). These increases were partially offset by reduced revenues from the Barking generating plant in the United Kingdom, due to the loss in late 2002 of the long term offtake agreement with TXU Europe (described below), resulting in 275 megawatts of power previously supplied to TXU Europe now being sold under short term bilateral agreements. AESO prices averaged $62.99 per megawatt hour in 2003, compared to average prices of $43.94 in 2002. Natural gas prices averaged $6.31 per gigajoule in 2003, compared to average prices of $3.84 in 2002.

Earnings for the three months ended December 31, 2003, increased by $12.3 million to $35.7 million, primarily due to a favourable tax adjustment in Australia, and the commencement in 2003 of the amortization of deferred availability incentives.

Earnings for the year ended December 31, 2003, increased by $17.4 million to $92.7 million, primarily due to higher prices received for electricity sold to the AESO, a favourable tax adjustment in Australia, improved operating results in ATCO Power's Australian generating plants, the commencement in 2003 of the amortization of deferred availability incentives and improved operating results in Alberta Power (2000). This increase was partially offset by higher fuel costs arising from higher natural gas prices and reduced earnings from the Barking generating plant in the United Kingdom, due to the loss in late 2002 of the long term offtake agreement with TXU Europe (described below), resulting in 275 megawatts of power previously supplied to TXU Europe now being sold under short term bilateral agreements. The $92.7 million of earnings amounted to 35.8% of consolidated earnings of the Corporation.

Operating expenses for the year ended December 31, 2003, increased by $15.9 million to $351.9 million, primarily the result of the commissioning of the New ATCO Power Generating Plants and higher natural gas fuel costs in Alberta.

ATCO Power completed construction of the New ATCO Power Generating Plants in 2003 for a total cost of approximately $745 million, of which ATCO Power's share was approximately $430 million. These costs were approximately 13% above original cost estimates, primarily due to labour and engineering markets in Alberta, which tightened during construction, and increased equipment, financing and foreign exchange costs. A portion of the additional costs will be recoverable over the term of the commercial contracts.

On November 19, 2002, an administration order was issued by a United Kingdom court for TXU Europe, which had a long term offtake agreement for 27.5% of the power produced by the Barking power plant, a 1,000 megawatt plant in London, England, in which the Corporation, through Barking Power Limited, has a 25.5% equity interest. An administration order is similar to a Chapter 11 bankruptcy filing in the United States. Barking Power Limited has filed a claim with the Administrator and is working with the Administrator and Creditors' Committees on liquidation of TXU Europe and settlement of claims. The Barking power plant will continue to supply 725 megawatts of power under long term contracts. The 275 megawatts of power previously supplied to TXU Europe is being sold under short term bilateral agreements.

At December 31, 2003, all of ATCO Power's non-regulated independent cogeneration and generating plants were in service, with the exception of the Brighton Beach project which is under construction.

A partnership formed by ATCO Power and Ontario Power Generation ("OPG") is constructing and will operate the Brighton Beach power plant, a 580 megawatt natural gas-fired combined cycle generating plant at the site of the former J.C. Keith Generating Station, near Windsor, Ontario. Coral Energy Canada Inc. has agreed to supply and pay for the natural gas to be used at the plant and will own, market and trade all the electricity produced. Construction is progressing with commercial operation scheduled for the summer of 2004. ATCO Power owns a 40% interest in the project, ATCO Resources owns 10% and OPG owns 50%. The estimated costs to complete the generating plant have increased from original estimates by approximately 19% to $562 million due to higher supply and assembly costs for the heat recovery steam generator, higher costs for civil works and changes in engineering scope. In addition, ATCO Power has provided a contingency of $10 million for unforeseen commissioning costs. ATCO Power's share of the total estimated cost is $230 million.

On September 8, 2003, SaskPower International Inc. announced that it had selected ATCO Power as its joint venture partner to potentially develop up to 150 megawatts of wind generation power in Saskatchewan.

In 2001, Alberta Power (2000) and the Alberta Balancing Pool entered into an agreement which gave the Alberta Balancing Pool control of the 150 megawatt, coal-fired H.R. Milner generating plant effective January 1, 2001 and the right to sell it until September 30, 2003, failing which the rights to control the generating plant would revert to Alberta Power (2000). In return, Alberta Power (2000) was paid $63.5 million, the net book value of the generating plant and coal inventory. Alberta Power (2000) operated the generating plant under a cost of service contract with the Alberta Balancing Pool. On August 6, 2003, the Alberta Balancing Pool announced that it had entered into an agreement for the sale of plant. Alberta Power (2000) extended its cost of service contract until January 29, 2004, when the plant was sold by the Alberta Balancing Pool to a third party. As part of the sale, Alberta Power (2000) was relieved of all decommissioning risk, including any environmental liabilities incurred while Alberta Power (2000) was operating the generating plant.

Logistics and Energy Services

Revenues from the Logistics and Energy Services Business Group for the three months ended December 31, 2003, increased by $51.2 million to $315.5 million, primarily due to higher prices for natural gas purchased for ATCO Midstream's customers and higher natural gas liquids prices, partially offset by the impact of the 2003/2004 rate decision for ATCO Pipelines, and reduced business activity in ATCO Frontec, primarily resulting from the expiry of a contract in September 2003 with the Department of National Defence to provide support services for six peace-keeping installations in Bosnia-Herzegovina (the "Balkans contract").

Revenues for the year ended December 31, 2003, increased by $329.7 million to $1,263.4 million, largely due to higher natural gas liquids prices and higher prices for natural gas purchased for ATCO Midstream's customers, partially offset by the impact of the 2003/2004 rate decision for ATCO Pipelines and lower revenues from ATCO Frontec projects, primarily reflecting the expiry of the Balkans contract.

Earnings for the three months ended December 31, 2003, decreased by $5.1 million to $14.3 million, primarily due to the impact of the 2003/2004 rate decision for ATCO Pipelines, and lower earnings from gas gathering and processing and storage operations in ATCO Midstream, partially offset by higher earnings from natural gas liquids in ATCO Midstream.

Earnings for the year ended December 31, 2003, decreased by $3.6 million to $60.8 million, primarily due to the impact of the 2003/2004 rate decision for ATCO Pipelines and lower earnings from ATCO Frontec projects and ATCO Midstream's storage operations, partially offset by higher earnings from ATCO Midstream's natural gas liquids operations. The $60.8 million of earnings amounted to 23.4% of consolidated earnings of the Corporation.

Operating expenses for the year ended December 31, 2003, net of intersegment expenses, increased by $105.6 million, primarily due to higher natural gas prices on gas sales by ATCO Midstream and higher shrinkage gas and power costs in ATCO Midstream.

Technologies and Other Businesses

Revenues from Technologies and Other Businesses for the three months ended December 31, 2003, increased by $8.2 million to $34.2 million, primarily due to increased business activity and commencement of work for new customers.

Revenues for the year ended December 31, 2003, increased by $24.9 million to $126.8 million, largely due to increased business activity and commencement of work for new customers.

Earnings for the three months ended December 31, 2003, increased by $2.3 million to $5.1 million, primarily due to increased business activity and cost containment initiatives.

Earnings for the year ended December 31, 2003, increased by $8.0 million to $19.1 million, largely due to increased business activity and cost containment initiatives. The $19.1 million of earnings amounted to 7.4% of consolidated earnings of the Corporation.

ATCO I-Tek Business Services Ltd. has entered into a 10-year contract with Direct Energy Marketing Limited ("Direct Energy") to provide billing and customer care services to nearly one million Alberta customers. Commencement of the contract is conditional upon the closing of the sale of ATCO Gas' and ATCO Electric's retail operations to Direct Energy (see "Business Risks – Regulated Operations – Sale of Retail Operations").

Corporate

Earnings for the three months ended December 31, 2003, decreased by $4.2 million to $(4.9) million, primarily due to higher interest expense and preferred share dividends resulting from the issue of $100.0 million of 6.14% Debentures in November 2002 and the Series W and Series X Preferred Shares, net of investment income.

Earnings for the year ended December 31, 2003, decreased by $13.3 million to $(14.9) million, primarily due to higher interest expense and preferred share dividends resulting from the issue of $100.0 million of 6.14% Debentures in November 2002 and the Series W and Series X Preferred Shares, net of investment income.

In 2001, the Corporation received and paid an income tax reassessment of $12.9 million relating to the 1996 disposal of ATCOR Resources Ltd. Management did not agree with this reassessment and contested the matter with tax authorities. Accordingly, the payment was recorded as a reduction of future income tax liabilities. During 2003, the Corporation was successful in appealing the reassessment to the Tax Court of Canada. However, the Federal Government has commenced an appeal of the Tax Court's decision with the Federal Court of Appeal. Consequently, the future income tax reduction of $12.9 million has not been adjusted.

REGULATORY MATTERS

Regulated operations are conducted by ATCO Electric, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd., CU Water, and the generating plants of Alberta Power (2000), all of which are wholly owned subsidiaries of the Corporation's wholly owned subsidiary, CU Inc.

In August 2002, the Government of Alberta announced changes to utility legislation designed to improve the environment for retail competition in the Province. Amendments to the Electric Utilities Act and Gas Utilities Act received Royal Assent in March 2003 and were proclaimed in force in June 2003. These changes were designed to bring customer choice for both gas and electricity into closer alignment, as well as to move towards consistent regulatory treatment of investor-owned and municipally-owned utilities. In July 2003, ATCO Gas filed its compliance application in accordance with the new legislation.

In December 2003, the AEUB issued a decision approving the implementation of the "One Bill Model" no later than April 1, 2004. The One Bill Model will ensure that customers who choose to purchase their natural gas requirements from a retailer will receive only one bill for natural gas service. Previously, customers would receive a bill from the retailer for the purchase of the commodity and a separate bill from ATCO Gas for the delivery service.

In April 2003, the AEUB determined that it would proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to determine the rate of return on equity and capital structure for all utilities under the jurisdiction of the AEUB. Hearings were completed in January 2004. A decision from the AEUB is not expected until the third quarter of 2004.

In May 2003, the AEUB issued a decision respecting affiliate transactions between ATCO Electric, ATCO Gas and ATCO Pipelines (the "ATCO utilities") and their affiliates. The decision and the resulting Code of Conduct set the framework for ongoing affiliate transactions. The ATCO utilities must be able to demonstrate that services or products from an affiliate have been acquired at a price that is no more than the fair market value of such services or products.

ATCO Electric

In December 2000, the Province of Alberta issued regulations providing for the deferral of price and volume variance in excess of forecast amounts in respect of the supply of electricity by distributors to their customers for the year ended December 31, 2000. In 2002, the AEUB issued decisions approving the collection by ATCO Electric of its deferred costs from customers, and permitting ATCO Electric to sell these deferred costs and related rights. In 2002, ATCO Electric sold deferred costs of $81 million to an unrelated purchaser for equivalent cash consideration. Generally accepted accounting principles required that this transaction be accounted for as a financing arrangement rather than a sale. Accordingly, the cash received resulted in the recording of a deferred electricity cost obligation rather than a reduction of deferred electricity costs. The obligation bore interest at 3.3975%, which approximated the interest earned on the deferred costs. The obligation principal and interest incurred were paid to the purchaser as the deferred costs and interest earned were collected from customers. At December 31, 2003, the outstanding obligation was nil.

In June 2003, the AEUB issued a decision approving the collection from customers of interim balances as applied for by ATCO Electric of $4.8 million for the 2002 regulated rate option deferral accounts and $16.6 million for the 2003 regulated rate option energy deferral account accumulated for the first 3 months of 2003. The AEUB directed that ATCO Electric collect these interim balances from customers over the period July 1, 2003, to December 31, 2003.

In August 2002, ATCO Electric filed a general tariff application with the AEUB for the 2003, 2004 and 2005 test years. In a decision dated December 11, 2002, the AEUB approved interim rates effective January 1, 2003. Hearings for ATCO Electric's general tariff application for the 2003, 2004 and 2005 test years commenced on April 15, 2003, and were completed in May 2003. During the hearings, ATCO Electric withdrew the 2005 test year from its application in light of uncertainty around whether the equity component and return for 2005 would be determined based on the merits of its application or through the generic cost of capital proceeding.

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. However, the 2004 rate of return on common equity and the common equity ratios for the transmission and distribution operations will be determined as part of the generic cost of capital hearing. Certain matters relating to transactions with affiliates will be addressed in separate proceedings during 2004. ATCO Electric, as directed by the AEUB, has refiled the 2003 and 2004 revenue requirements, incorporating the findings in the decision. In a decision dated February 17, 2004, the AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years, accepting the refiling with no material changes.

In September 2003, ATCO Electric received approval from the AEUB to build a $95.0 million, 350 kilometre 240 kilovolt transmission line between Fort McMurray and Whitefish Lake. The line includes three substations and is expected to be completed by August 31, 2004.

ATCO Electric is obligated to supply energy under the regulated rate option to the residential, farm and small commercial customers in its designated service area who do not choose an unregulated retailer. ATCO Electric purchases electricity from the AESO at spot prices to supply the regulated rate option customers, the costs for which are collected from customers at rates approved by the AEUB. In November 2003, the government of Alberta revised its regulations, effective January 1, 2004, and as a result, ATCO Electric will now be at risk for electric energy supply and will no longer be able to flow through the AESO price to customers. A further revision to the regulations in November permitted the AEUB to extend the period for implementation to July 1, 2004 upon application. In December 2003, the AEUB issued a decision approving ATCO Electric's application to extend the implementation date to July 1, 2004. Under the revised regulations, ATCO Electric is obligated to provide a fixed price regulated rate option to customers until July 1, 2006, and a regulated rate option based on actual spot prices thereafter.

ATCO Gas

In August 2002, ATCO Gas filed a general rate application with the AEUB for the 2003 and 2004 test years. In December 2002, the AEUB issued a decision approving rates on an interim basis effective January 1, 2003. In a decision dated October 1, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.50% for 2003 and 2004 and a common equity ratio of 37%. Certain matters relating to transactions with affiliates will be addressed in separate proceedings during 2004. ATCO Gas, as directed by the AEUB, has refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. The AEUB has not yet issued its final determination of the revenue requirements for the 2003 and 2004 test years.

In February 2003, the AEUB issued a decision approving the methodology of distributing the proceeds from the sale of the Beaverhill Lake and Fort Saskatchewan natural gas producing properties, and in March 2003, $23 million of the related sales proceeds was refunded to ATCO Gas' North division customers. The sale has no significant impact on earnings.

In March, 2003, $2.5 million was refunded to ATCO Gas' North division customers. This resulted from the AEUB approval of the final 2002 distribution service rates for ATCO Gas' North division, as established in a negotiated settlement.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties located in the City of Calgary, known as the Calgary Stores Block, for $6.6 million and subsequently issued a decision allocating $4.1 million of the proceeds to customers. Leave to appeal this decision was granted on July 12, 2002. On January 27, 2004, the Alberta Court of Appeal issued a decision which overturned the AEUB decision and directed the AEUB to allocate $5.4 million of the proceeds to ATCO Gas. ATCO Gas has not recorded the impact of the appeal decision to date as the period to appeal the court's decision has not yet expired.

ATCO Pipelines

In January 2003, the AEUB issued a decision approving ATCO Pipelines' negotiated settlement of the 2001/2002 exchange deferred account deficit, which arose from the exchange mechanism utilized to deliver net producer transportation quantities sourced from the ATCO system onto the system owned by NOVA Gas Transmission Ltd. The decision approved mechanisms to collect ATCO Pipelines' South division deficit of approximately $9.0 million over a two year period. It further allowed the collection of ATCO Pipelines' North division deficit of $2.3 million in 2003. Approximately $3.5 million remains to be collected in 2004. The decision also provided for the recovery of carrying costs.

In February 2003, ATCO Pipelines filed a general rate application for the 2003 and 2004 test years. In a decision dated December 2, 2003, the AEUB approved, among other things, a rate of return on common equity of 9.50% and a common equity ratio of 43.5% for 2003. The rate of return on common equity and the common equity ratio for 2004 will be determined as part of the generic cost of capital hearing. Certain matters relating to transactions with affiliates will be addressed in separate proceedings during 2004. ATCO Pipelines, as directed by the AEUB, has refiled the 2003 and 2004 general rate application, incorporating the findings in the decision. The AEUB has not yet issued its final determination of the revenue requirements for the 2003 and 2004 test years.

In October 2003, ATCO Pipelines filed a 2004 Phase II general rate application for new rates. This application is part of a broader process through which the AEUB will address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd.

LIQUIDITY AND CAPITAL RESOURCES

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

Cash flow from operations for the three months ended December 31, 2003, decreased by $18.2 million to $153.3 million, primarily the result of higher current income taxes resulting from timing differences in the recognition of revenues and expenses for tax reporting purposes and decreased deferred availability incentives in Alberta Power (2000), partially offset by stronger earnings.

Cash flow from operations for the year ended December 31, 2003, increased by $21.2 million to $525.8 million, primarily due to stronger earnings, partially offset by higher current income taxes resulting from timing differences in the recognition of revenues and expenses for tax reporting purposes and decreased deferred availability incentives in Alberta Power (2000). In addition, in the first quarter of 2002, ATCO Gas refunded to customers a total of $405.6 million related to the sale of the Viking property, of which $20.6 million reduced cash flow from operations.

Investing for the three months ended December 31, 2003, decreased by $21.3 million to $125.0 million, primarily due to the collection of non-current deferred electricity costs and changes in non-cash working capital in respect of investing activities, partially offset by higher capital expenditures. Capital expenditures for the three months ended December 31, 2003, increased by $21.6 million to $176.7 million, primarily due to increased investment in regulated electric transmission and natural gas distribution projects, partially offset by lower investment in non-regulated power generation projects.

Investing for the year ended December 31, 2003, excluding the $107.7 million sale of the Viking property in 2002, decreased by $93.0 million to $434.0 million, primarily due to lower capital expenditures and increased proceeds on disposal of other property, plant and equipment, partially offset by changes in non-cash working capital in respect of investing activities. Investing for 2002, including the impact of the sale of the Viking property, was $419.3 million. Capital expenditures for 2003 decreased by $74.1 million to $495.7 million, primarily due to lower investment in non-regulated power generation projects and in regulated natural gas transmission projects, partially offset by increased investment in regulated natural gas distribution and regulated electric generation projects.

During the three months ended December 31, 2003, the Corporation redeemed $42.0 million of notes payable, issued $12.0 million of long term debt and redeemed $66.8 million of long term debt and $5.5 million of non-recourse long term debt, resulting in a net debt reduction of $102.3 million.

During the year ended December 31, 2003, the Corporation issued $25.5 million of long term debt and $40.7 million of non-recourse long term debt for the Brighton Beach project, and redeemed $60.0 million of 7.25% debentures, $79.1 million of other long term debt and $38.0 million of non-recourse long term debt, resulting in a net debt reduction of $110.9 million.

A planned issue of $180.0 million of debentures by CU Inc. in 2003 was deferred until January 2004 pending clarification of one of the Corporation's credit ratings (see "Credit Ratings"). As a result of the uncertainty surrounding the timing of the receipt of the credit rating, the Corporation utilized its cash resources in late 2003 to temporarily pay down outstanding debt. These payments amounted to approximately $210 million, of which approximately $150 million was advanced to ATCO Gas and ATCO Electric, and approximately $60 million to other subsidiaries of the Corporation. In January 2004, the amounts advanced to ATCO Gas and ATCO Electric were repaid from the proceeds of the CU Inc. $180.0 million issue of 5.432% Debentures and the remaining amounts were replaced with bank borrowings.

During 2003, the opening balance of the deferred electricity cost obligation was reduced by $51.0 million, which represents the amount of the deferred electricity cost obligation collected and remitted during the period January 1, 2003, to December 31, 2003. The deferred electricity cost obligation has now been fully repaid.

In April 2003, the Corporation issued 6,000,000 Series X Preferred Shares, having a dividend rate of 6.00%, at a price of $25.00 per share, for aggregate gross proceeds of $150.0 million. The net proceeds of the issue were added to the general funds of the Corporation to be used for general corporate purposes including capital expenditures.

Capital expenditures to maintain capacity, meet planned growth and fund future development activities are expected to be approximately $550 million in 2004. Included in these capital expenditures are committed amounts relating to ATCO Electric's 350 kilometre 240 kilovolt transmission line between Fort McMurray and Whitefish Lake, ATCO Power's Brighton Beach project, a 580 megawatt natural gas-fired combined cycle generating plant in Windsor, Ontario and a project to improve operating efficiency at Alberta Power (2000)'s Sheerness and Battle River generating plants. ATCO Electric's transmission line and the Brighton Beach project are currently under construction. These three projects are expected to be completed in 2004, at a cost of approximately $100 million. The remainder of the 2004 capital expenditures, amounting to approximately $450 million, is uncommitted and relates primarily to regulated operations.

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

Contractual Obligations	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
	Payments Due by Period ($ Millions)				
Long term debt	1,805.3	113.8	304.5	162.0	1,225.0
Non-recourse long term debt	852.4	46.3	118.5	136.9	550.7
Operating leases	71.6	12.8	23.1	20.6	15.1
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1)	1,115.5	115.5	228.4	222.0	549.6
Alberta Power (2000) coal purchase contracts (2)	874.7	42.0	86.6	91.1	655.0
Alberta Power (2000) capital expenditures (3)	9.9	9.9	-	-	-
ATCO Power natural gas fuel supply contracts (4)	457.3	59.9	122.7	117.9	156.8
ATCO Power operating and maintenance agreements (5)	103.9	16.6	25.0	27.3	35.0
ATCO Power capital expenditures (6)	23.8	22.9	0.6	0.3	-
Other	21.5	20.5	1.0	-	-
Total	5,335.9	460.2	910.4	778.1	3,187.2

<u>Notes:</u>

(1) ATCO Gas has obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on December 31, 2003, and assumes a remaining life of 10 years for the gas reserves. The cost of natural gas purchased under these obligations is recoverable from ATCO Gas' customers. These purchase obligations would transfer to Direct Energy upon the sale of the retail energy business of ATCO Gas.

(2) Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the power purchase arrangements.

(3) Alberta Power (2000) has entered into contracts with suppliers to improve operating efficiency at certain of its generating plants.

(4) ATCO Power has various contracts to purchase natural gas for its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 82% of these costs. The balance of 18% is currently being recovered under short term bilateral agreements.

(5) ATCO Power has various contracts with suppliers to provide operating and maintenance services at certain of its generating plants.

(6) ATCO Power has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.

At December 31, 2003, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

	Total	Used	Available
		($ Millions)	
Long term committed	350.0	16.2	333.8
Short term committed	624.3	49.8	574.5
Uncommitted	178.5	14.1	164.4
Total	1,152.8	80.1	1,072.7

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

Current and long term future income tax liabilities of $238.5 million at December 31, 2003, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

On May 20, 2002, the Corporation commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The offer expired on May 19, 2003. Over the life of the offer, 17,300 shares were purchased, all of which were purchased in 2003. On May 20, 2003, the Corporation commenced a normal course issuer bid for the purchase of up to 3% of the outstanding Class A shares. The offer will expire on May 19, 2004. From May 20, 2003, to February 6, 2004, 56,600 shares have been purchased, all of which were purchased in 2003.

It is the policy of the Corporation to pay dividends quarterly on its Class A and Class B shares. In 2003, the Corporation increased the dividends on Class A and Class B shares by $0.08 per share, the same increase as in 2002. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. For the first quarter of 2004, the quarterly dividend payment has been increased by $0.02 to $0.53 per share. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

Credit Ratings

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

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

Notes:

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

(2) *In January 2004, Standard and Poor's ("S&P") announced it had lowered its ratings on the Corporation's debentures and preferred shares from A to A- and from P-1 (low) to P2 (high), respectively, and CU Inc.'s debentures from A+ to A. At the same time, the ratings were removed from CreditWatch, where they were placed March 5, 2003. The outlook is stable.*

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

On January 16, 2004, CU Inc. filed a base shelf prospectus which permits CU Inc. to issue up to an aggregate of $750.0 million of debentures over the twenty-five month life of the prospectus. On January 23, 2004, CU Inc. issued $180.0 million of 5.432% Debentures due January 23, 2019, at a price of 100 to yield 5.432%. The proceeds of the issue were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

DISCLOSURE OF OUTSTANDING SHARE DATA

At February 25, 2004, the Corporation had outstanding 41,165,891 Class A shares and 22,247,494 Class B shares.

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

If a take-over bid is made for the Class B shares, which would result in the offeror owning more than 50% of the outstanding Class B shares and which would constitute a change in control of the Corporation, owners of Class A shares are entitled, for the duration of the bid, to exchange their Class A shares for Class B shares and to tender such Class B shares pursuant to the terms of the take-over bid. Such right of exchange is conditional upon the completion of the take-over bid giving rise to the right of exchange, and if the take-over bid is not completed, then the right of exchange shall be deemed never to have existed. In addition, owners of the Class A shares are entitled to exchange their shares for Class B shares of the Corporation if ATCO Ltd., the present controlling share owner of the Corporation, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares of the Corporation. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering. The complete text of the rights of exchange attached to the Class A shares is set out in a Certificate of Amendment dated September 10, 1982 issued to the Corporation pursuant to the Canada Business Corporations Act.

TRANSACTIONS WITH RELATED PARTIES

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $2.8 million, recovered administrative expenses and business development costs totaling $3.0 million, and incurred administrative expenses and corporate signature rights totaling $6.8 million. The Corporation also incurred advertising and promotion expenses from an entity related through common control totaling $1.1 million. These transactions are in the normal course of business and under normal commercial terms.

BUSINESS RISKS

During 2002, the Government of Canada ratified the Kyoto Protocol. The Corporation is unable to determine what impact, if any, the ratification will have on its operations as the implementation plan has not yet been released by the Government. It is anticipated that the Corporation's power purchase arrangements ("PPA's") relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the protocol.

Regulated Operations

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

ATCO Electric is obligated to supply energy under the regulated rate option to the residential, farm and small commercial customers in its designated service area who do not choose an unregulated retailer. ATCO Electric purchases electricity from the AESO at spot prices to supply the regulated rate option customers, the costs for which are collected from customers at rates approved by the AEUB. In November 2003, the government of Alberta revised its regulations, effective January 1, 2004, and as a result, ATCO Electric will now be at risk for electric energy supply and will no longer be able to flow through the AESO price to customers. A further revision to the regulations in November permitted the AEUB to extend the period for implementation to July 1, 2004 upon application. In December 2003, the AEUB issued a decision approving ATCO Electric's application to extend the implementation date to July 1, 2004. Under the revised regulations, ATCO Electric is obligated to provide a fixed price regulated rate option to customers until July 1, 2006, and a regulated rate option based on actual spot prices thereafter.

Based on customer requirements in 2003, ATCO Electric estimates that this new policy will require it to purchase approximately 2,000 gigawatt hours (approximately $100 million based on current prices) of electricity per year on a fixed price basis. ATCO Electric will attempt to minimize the credit risk and price risk for volume variances associated with buying electricity in the forward market at fixed prices and then selling to customers at fixed rates by entering into appropriate hedging strategies, adopting prudent credit policies and negotiating with customers a risk premium, a hedging framework and a pricing mechanism involving frequent load forecast updates and rate adjustments. There can be no guarantee that ATCO Electric will be able to recover all of the costs associated with this new energy purchasing policy.

Sale of Retail Operations

In December 2002, Direct Energy agreed to purchase the retail energy businesses of ATCO Gas and ATCO Electric, subject to the satisfaction of certain conditions, including the receipt of required regulatory approvals and the government of Alberta amending certain natural gas and electricity legislation. In December 2003, the AEUB issued decisions approving the transfer of the retail operations of ATCO Gas and ATCO Electric to Direct Energy, appointing Direct Energy provider of the natural gas Default Rate Tariff and electricity Regulated Rate Tariff in the ATCO Gas and ATCO Electric service territories and approving the tariff rate structure of Direct Energy Regulated Services, ATCO Gas and ATCO Electric. The City of Calgary has filed leave to appeal the AEUB decision approving the transfer of the retail operations. The Corporation is reviewing the AEUB decisions and certain other conditions which must be satisfied in order to close the sale of its retail business to Direct Energy.

If the sale does close on the anticipated terms, ATCO Gas and ATCO Electric will no longer be involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return. The sale does not include any of the distribution and transmission facilities used to deliver natural gas and electricity to customers.

Alberta Power (2000)

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

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

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

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

Should accumulated penalties plus estimated future penalties exceed accumulated incentives plus estimated future incentives, the shortfall will be expensed in the year the shortfall occurs.

At December 31, 2003, the Corporation had recorded $43.3 million of deferred availability incentives.

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

As a result of unprecedented drought conditions, the water level in the cooling pond used by the Battle River plant in its production of electricity had fallen to an all-time low in early 2003, and the Corporation made a force majeure claim in respect of short term curtailed plant production which was experienced during the first quarter of 2003. Water levels continue to be below normal levels, however sufficient water is currently available to permit the plant to produce electricity according to its PPA contractual requirements. The Corporation is preparing submissions for the arbitration hearings scheduled to commence May 3, 2004, in respect of the force majeure claim.

Non-Regulated Operations

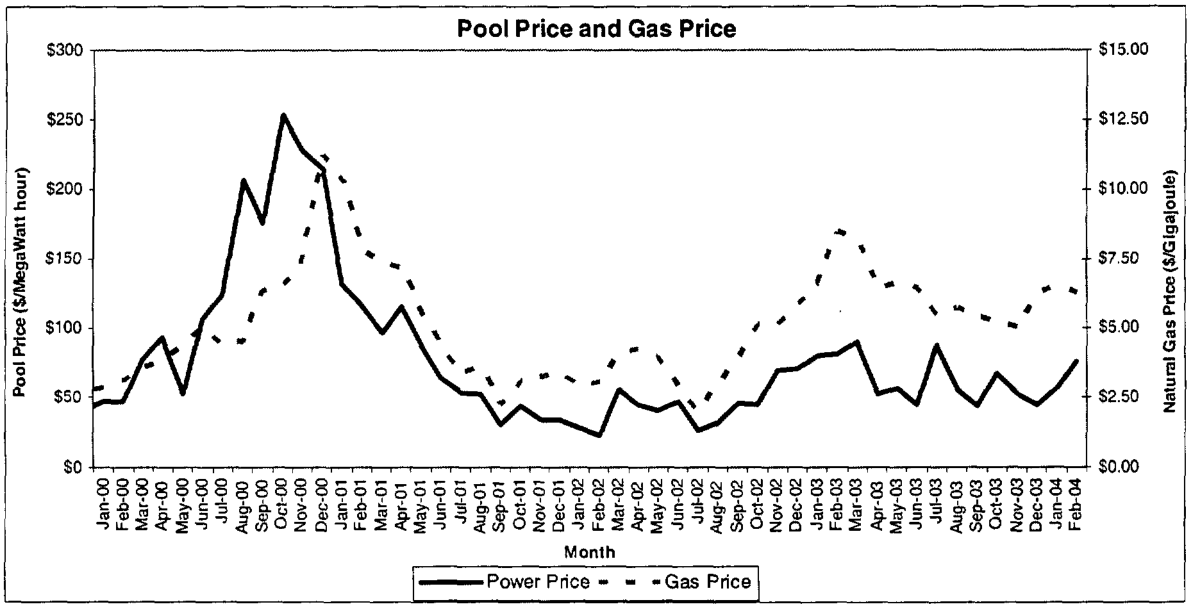
The Corporation's non-regulated operations are complementary to its traditional regulated businesses and are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its regulated operations. The Corporation's non-regulated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

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

ATCO Power

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2003, sales from approximately 66% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 34% consisted primarily of sales to the AESO. In 2004, the portion of generating capacity subject to long term agreements is expected to be approximately 74%, while the remaining 26% is expected to consist primarily of sales of electricity to the AESO. These sales are dependent on prices in the Alberta electricity spot market. The majority of the electricity sales to the AESO are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a strong correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation. The correlation is expected to increase in the future as customer load grows and older plants are decommissioned.

Electricity prices and natural gas prices can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period January 2000 to February 2004.



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

ATCO Power has financed its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. These guarantees cover the following items:

a) Equity contributions – Represents equity funding requirements needed to complete construction of the project being built. At December 31, 2003, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is anticipated to be $35.3 million.

b) Completion of construction – Represents completion guarantees associated with project financing whereby non-completion of a project by a certain date will require the repurchase of all or a portion of the project debt. At December 31, 2003, the maximum value of the obligation under this guarantee for the Brighton Beach project financing is $161.2 million, with an expiry date of September 30, 2006.

c) Project cash flows – Represents annual payments related to maintaining base case margins for electricity prices on the merchant power component of the project, being 24 megawatts for the Scotford project and 48 megawatts for the Muskeg River project. These guarantees became effective upon the commercial operation of the plants and exist until 2022, when the project debt is to be fully repaid. The amounts payable under these guarantees will vary each year depending on the pool price received for the merchant power generated. Any payments made to maintain the project base case margins will either be available for distribution to the owners or be applied to mandatory prepayment of the project debt in accordance with the terms of the project financing agreement depending upon the specific operating results of the plant. At December 31, 2003, $0.4 million was payable for the Muskeg River and Scotford projects.

d) Reserve amounts – Represents amounts to be set aside for major maintenance and debt service reserves as stipulated in the project's financing agreement. These reserves are intended to be funded with project cash flows. To the extent that project cash flows are insufficient to meet reserve requirements, Canadian Utilities

Limited may choose to provide guarantees in lieu of ATCO Power providing security. At December 31, 2003, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
	($ Millions)	
ATCO Power Alberta Limited Partnership ("APALP") project financing	Nil (1)	6.7
Joffre project financing	Nil (2)	4.8
Muskeg River project financing	Nil (1)	5.3
Scotford project financing	Nil (1)	5.3

Notes:
(1) No major maintenance reserve required for this financing.
(2) Reserve requirements of $1.4 million met with project cash flows.

e) Prepaid operating and maintenance fee – Should ATCO Power cease to be operator of the APALP generating plants as a result of a termination of the operating agreement, Canadian Utilities Limited has guaranteed the payment of the unamortized portion of the prepaid operating and maintenance fee to APALP, the proceeds of which are to be used to repay project debt in accordance with the project financing agreements. This guarantee, which declines by $1.2 million per year, remains in effect until 2016, when the project debt is to be fully repaid. At December 31, 2003, the maximum value of the guarantee is $33.6 million.

f) Purchase project assets – Represents an obligation to purchase the Scotford and Muskeg River projects at a price sufficient to repay any outstanding project debt upon the occurrence of any one of the following very limited events:

(i) where all of the following events have occurred:
- the insolvency of ATCO Power;
- the failure of the project debt lenders to complete a sale of the project pursuant to their security within a fixed period of time; and
- the project purchaser of electricity and steam elects to terminate its purchase contracts due to the insolvency of ATCO Power;

(ii) where the project purchaser of electricity and steam does not remove ATCO Power as operator of the project after an event of default under the project financing agreements in circumstances where such default is either:
- a deliberate or willful breach of a project financing agreement; or
- where ATCO Power has failed to co-operate with the lenders in a sale of the project; and

(iii) where the project purchaser of electricity and steam terminates its purchase contracts for the project as a result of a default by ATCO Power's project minority joint venturers. ATCO Power has the right to cure any such default by acquiring the minority interest which is in default.

These guarantees remain in effect until the project debt is fully repaid. At December 31, 2003, no such events have occurred.

Canadian Utilities Limited has also guaranteed ATCO Power's duties to operate the Barking Power, Scotford and Muskeg River generating plants in accordance with acceptable industry operating standards under the relevant project contracts. Canadian Utilities Limited has guaranteed ATCO Power's obligation to remediate certain deficiencies at the Oldman River project in the amount of $2.4 million. In addition, Canadian Utilities Limited has posted acceptable credit support in the amount of $2.2 million with respect to builders' liens filed against the Cory Project.

ATCO Power (80%) and ATCO Resources Ltd. (20%), a wholly owned subsidiary of Canadian Utilities Limited's parent corporation, ATCO Ltd., have a joint venture in the above projects. The foregoing guaranteed amounts represent ATCO Power's 80% interest. Canadian Utilities Limited has also guaranteed similar obligations in respect of ATCO Resources' 20% interest. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities Limited for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest.

To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

Contingencies

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

Hedging

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

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.

OFF-BALANCE SHEET ARRANGEMENTS

Unrecorded future income tax liabilities of the regulated operations amounted to $167.5 million at December 31, 2003. This balance includes $46.3 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. The remainder, amounting to $121.2 million, is expected to be recovered from utility customers through inclusion in future rates. There are tax loss carryforwards of $0.7 million for which no tax benefit has been recorded. These losses begin to expire in 2007. In addition, the Corporation uses various derivative instruments to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. Note 19 to the financial statements sets out the instruments in place at December 31, 2003.

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

CRITICAL ACCOUNTING ESTIMATES

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

Deferred Availability Incentives

As noted previously in the Business Risks section, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. As at December 31, 2003, the Corporation had recorded $43.3 million of deferred availability incentives. The amortization of deferred availability incentives, which was recorded in revenues, amounted to $7.5 million in 2003.

The amount of deferred availability incentives 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 best case, worst case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPA to arrive at the amortization for the quarter.

Compared to the most likely scenario recorded in revenues, the best case scenario would have resulted in higher revenues of approximately $4.0 million, whereas the worst case scenario would have resulted in lower revenues of approximately $3.5 million.

Employee Future Benefits

The Corporation's employee future benefits disclosures are based on three critical accounting estimates: (1) the expected long term rate of return on plan assets; (2) the liability discount rate; and, (3) the long term inflation rate.

The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Actual balanced fund performance over a longer period suggests that this premium is about 1%, which, when added to the long bond yield rate of 6.5% at the beginning of 2003, resulted in an expected long term rate of return of 7.5% for 2003. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, and asset diversification effect on portfolio returns.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years.

The liability discount rate reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate used to calculate the cost of benefit obligations in 2003 was 6.5%; the liability discount rate used to determine the accrued benefit obligations at the end of 2003 was reduced to 6.25%.

The expected long term rate of return has declined over the past two years, from 8.1% in 2001 to 7.5% in 2003. The result has been a decrease in the expected return on plan assets. The difference between the expected return and the actual return on plan assets results in an experience gain or loss on plan assets. The liability discount rate has also declined over the same period, from 6.9% at the end of 2001 to 6.25% at the end of 2003. The effect of this change has been to increase the accrued benefit obligations, resulting in experience losses in 2002 and 2003. In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10 percent of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation began amortizing a portion of the cumulative experience losses in 2003 for both pension benefit plans and other post employment benefit plans.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 10.5% for 2003 grading down over 10 years to 4.5%, and for other medical and dental costs, 4.0% for 2003 and thereafter. Combined with higher claims experience, the effect of these changes has been to increase the costs of other post employment benefits.

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

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan expense (income) for 2003 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2003 Pension Benefit Plans		**2003 Other Post Employment Benefit Plans**	
	Accrued Benefit Obligation	**Benefit Plan Expense (Income)**	**Accrued Benefit Obligation**	**Benefit Plan Expense (Income)**
	($ Millions)			
Expected long term rate of return on plan assets				
1% increase (1)	-	(3.5)	-	-
1% decrease (1)	-	3.5	-	-
Liability discount rate				
1% increase (1)	(52.2)	(0.3)	(2.8)	(0.3)
1% decrease (1)	52.2	0.3	2.8	0.3
Long term inflation rate (2)				
1% increase (1)	34.6	0.5	2.6	0.5
1% decrease (1)	(34.6)	(0.5)	(2.2)	(0.4)

Notes:

(1) *Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans expense (income), which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.*

(2) *The long term inflation rate for other post employment benefits plans is the assumed annual health care cost trend rate described in the weighted average assumptions.*

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2004, the Corporation will retroactively adopt the recommendations of the Canadian Institute of Chartered Accountants ("CICA") on stock based compensation. The recommendations require expensing of stock options. The impact on the financial statements resulting from the adoption of the recommendations is not expected to be material.

Effective January 1, 2004, the Corporation will retroactively adopt the recommendations of the CICA on accounting for asset retirement obligations. The recommendations require total retirement costs to be recorded as a liability at fair value, with a corresponding increase to property, plant and equipment. The impact on the financial statements resulting from the adoption of the recommendations is not expected to be material.

Effective January 1, 2004, the Corporation will prospectively adopt the recommendations of the CICA on accounting for asset impairment. The 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 income 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. The impact on the financial statements resulting from the adoption of the recommendations is not expected to be material.

During 2003, the Corporation adopted the CICA's accounting guideline pertaining to the identification, designation, documentation and effectiveness of hedging relationships for the purposes of applying hedge accounting.

February 25, 2004

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED

An ATCO Company

2003 ANNUAL INFORMATION FORM

February 25, 2004

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

"ATCO I-Tek" means ATCO I-Tek Inc. Prior to January 1, 2004, ATCO I-Tek was a division of the Corporation;

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

"ATCO Midstream" means ATCO Midstream Ltd.;

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

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

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

"ATCO Travel" means ATCO Travel Ltd.;

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

"BPL" means Barking Power Limited;

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

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

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

"CU" means Canadian Utilities Limited;

"CU Water" means CU Water Limited;

"EEEP" means the Edmonton Ethane Extraction Plant;

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

"Genics" means Genics Inc.;

"km" means kilometre;

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

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

"NLD" means Northland Utilities (NWT) Limited;

"NUY" means Northland Utilities (Yellowknife) Limited;

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

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

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

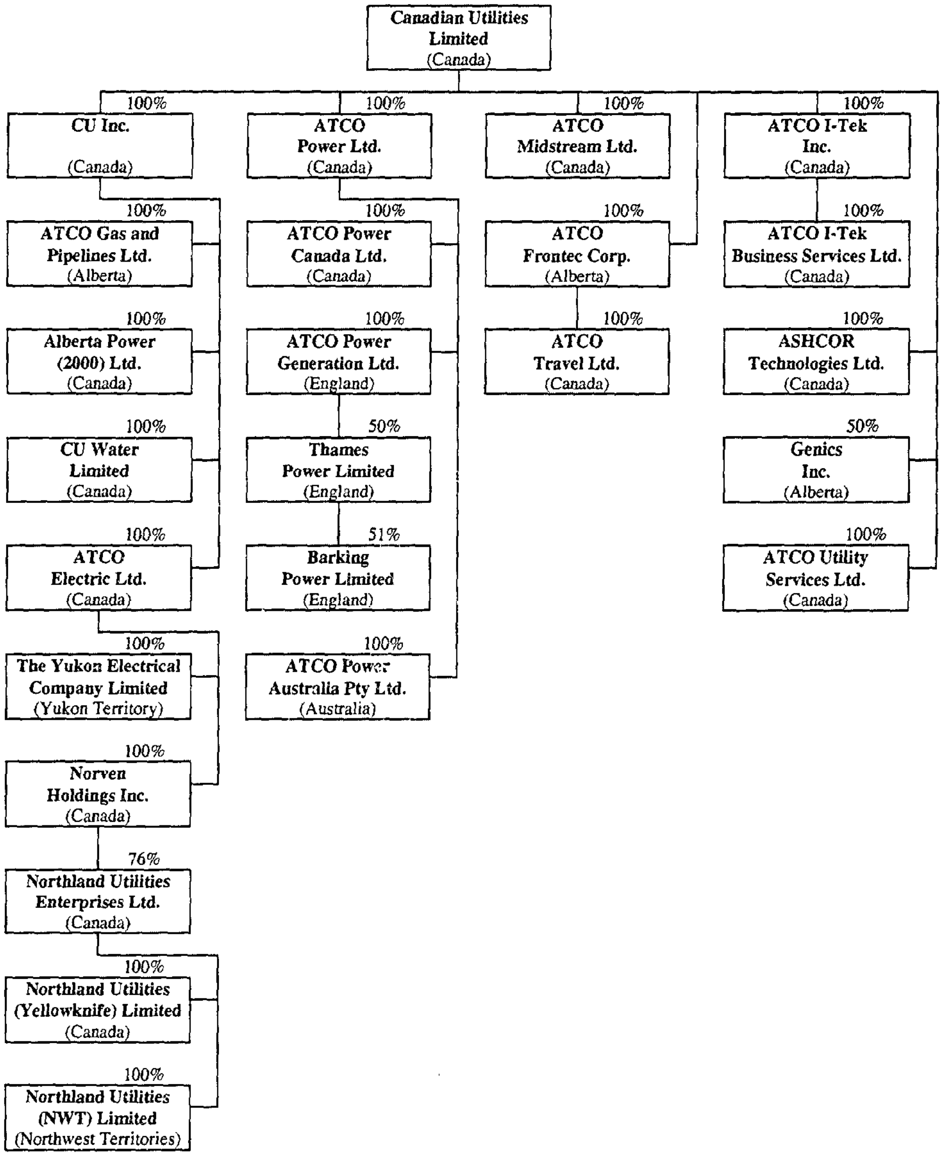
"Thames Power" means Thames Power Limited;

"YECL" means The Yukon Electrical Company Limited.

CANADIAN UTILITIES LIMITED

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

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



Note:

(1) At December 31, 2003, all of the non-voting shares of each of the above corporations were directly or indirectly owned by the Corporation.

CONSOLIDATED THREE YEAR FINANCIAL SUMMARY

	Year Ended December 31		
	2003	2002	2001
	($ Millions except per share data)		
Revenues	3,742.6	2,975.9	3,513.6
Earnings attributable to Class A and Class B shares (1) (2)	259.3	305.0	237.1
Earnings per Class A and Class B share (1)	4.09	4.81	3.74
Diluted earnings per Class A and Class B share (1)	4.07	4.79	3.72
Total assets	6,070.5	5,934.4	5,404.0
Long term debt	1,805.3	1,916.9	1,855.9
Non-recourse long term debt	806.1	821.1	673.8
Equity preferred shares	636.5	486.5	336.5
Class A and Class B share owners' equity	1,951.6	1,830.1	1,643.8
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O (3)	1.26	1.26	1.14
Series Q	1.48	1.48	1.48
Series R	1.33	1.33	1.33
Series S	1.65	1.65	1.65
Series T (4)	1.26	1.26	1.16
Series U (4)	1.26	1.26	1.16
Series V (5)	1.31	1.17	1.17
Series W (6)	1.44	-	-
Series X (7)	0.93	-	-
Class A and Class B shares	2.04	1.96	1.88

Notes:

(1) There were no discontinued operations or extraordinary items during these periods.
(2) The 2002 results include earnings of $67.3 million on the sale of the Viking-Kinsella natural gas producing property.
(3) The dividend was reset to $1.26 (5.05%) for the period between December 1, 2001, and December 1, 2006.
(4) The dividend was reset to $1.26 (5.05%) for the period between December 2, 2001, and December 2, 2006.
(5) The dividend was reset to $1.31 (5.25%) for the period between October 3, 2002, and October 3, 2007.
(6) Issued December 3, 2002.
(7) Issued April 17, 2003.

BUSINESS OF THE CORPORATION

The Corporation is a holding company. Its principal operating subsidiaries are engaged in regulated natural gas and electric energy operations, primarily in Alberta, and in related non-regulated operations. Regulated operations are conducted by ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water. Included in regulated operations are the generating plants of Alberta Power (2000), which were regulated by the AEUB until December 31, 2000, but are now governed by legislatively mandated PPA's that were approved by the AEUB. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the life of the related generating plant and December 31, 2020.

The Corporation has four Business Groups: Utilities, Power Generation, Logistics and Energy Services, and Technologies. For the purposes of financial disclosure, the Technologies Business Group is included in Technologies and Other Businesses. Corporate results, which include administrative expenses, earnings from corporate investments and financing charges, are accounted for as Corporate.

The Utilities Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, NLD, NUY and YECL, the regulated transmission and distribution of water by CU Water, and the provision of non-regulated engineering, procurement and construction services for customers in the utility, energy and telecommunications sectors by ATCO Utility Services.

The Power Generation Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power and the regulated supply of electricity by Alberta Power (2000).

The Logistics and Energy Services Business Group includes the regulated transportation of natural gas by ATCO Pipelines, the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, and the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec.

The Technologies Business Group and Other Businesses includes the development, operation and support of information systems and technologies by ATCO I-Tek, the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek Business Services, the sale of fly ash and other combustion byproducts produced in coal-fired electrical generating plants by ASHCOR Technologies, the manufacture of wood preservation products by Genics and the sale of travel services to both business and consumer sectors by ATCO Travel. In addition, the Corporation owns commercial real estate in Fort McMurray, Alberta.

Utilities

Natural Gas Operations

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

ATCO Gas' principal markets for the sale of natural gas are in the communities of Edmonton, Calgary, Airdrie, Camrose, Fort McMurray, Grande Prairie, Lethbridge, Lloydminster, Red Deer, St. Albert and Sherwood Park, which have a combined population of approximately 1,988,000. Also served are 280 smaller communities as well as rural areas having a combined population of approximately 553,000, located on or in the vicinity of ATCO Pipelines' transportation systems or the natural gas transportation pipelines of other companies. ATCO Gas serves approximately 888,000 customers with natural gas, of whom approximately 75% are located in the 11 communities named above.

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

	2003			2002		
	Sales Service	Transportation Service	Total	Sales Service	Transportation Service	Total
Residential	760,508	49,413	809,921	751,373	34,037	785,410
Commercial	72,707	4,729	77,436	72,052	4,101	76,153
Industrial	260	107	367	250	109	359
Other	16	-	16	1	-	1
Affiliates	27	-	27	29	-	29
Total	833,518	54,249	887,767	823,705	38,247	861,952

ATCO Gas owns and operates approximately 34,200 km of distribution mains. In addition, ATCO Gas owns modern service and maintenance facilities in major centres.

Sales and earnings of ATCO Gas are affected by temperature and consequently winter weather can have a significant impact. Usually, more than 50% of the earnings of ATCO Gas are generated during the months of January, February, November and December.

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

	2003			2002		
	Sales Service	Transportation Service	Total	Sales Service	Transportation Service	Total
			(petajoules)			
Residential	103.6	5.7	109.3	105.5	4.6	110.1
Commercial	84.5	15.6	100.1	86.7	15.5	102.2
Industrial	4.1	10.5	14.6	4.2	10.8	15.0
Other	5.8	-	5.8	4.4	-	4.4
Affiliates	0.2	-	0.2	0.2	-	0.2
Total	198.2	31.8	230.0	201.0	30.9	231.9

Natural Gas Supply

ATCO Gas purchases the major portion (approximately 84%) of its supplies of natural gas under contracts with terms of less than one year. The prices for these purchases are determined through a tender/bid process or a negotiation process and are generally referenced to indices related to other Alberta natural gas purchase contracts.

Additional natural gas requirements are provided under longer term contracts. The prices for these purchases are based on price indices related to prices paid under other third party natural gas purchase contracts in Alberta. As ATCO Gas' long term natural gas purchase contracts expire, ATCO Gas replaces them with contracts for one year or less. These shorter term contracts provide the flexibility needed to ensure that customers who choose to purchase their natural gas from other suppliers can be accommodated while still maintaining the supply security stipulated by legislation.

ATCO Gas also owns natural gas field storage facilities at Carbon, Alberta.

In the opinion of the management of ATCO Gas, the foregoing arrangements provide sufficient supplies of natural gas to meet the requirements of sales customers.

CU Water

CU Water is engaged in the transmission and distribution of water. CU Water owns and operates a distribution system to supply water to rural customers and small towns east of Edmonton. At the end of 2003, approximately 856 customers were being served directly by CU Water and, in addition, bulk water sales were being made to the town of Tofield and to approximately 192 commercial water haulers. The operations of CU Water are subject to regulation by the AEUB.

Electric Operations

ATCO Electric is engaged in the business of distributing and transmitting electric energy to 246 communities as well as rural areas in east-central and northern Alberta. Included are the communities of Drumheller, Lloydminster, Grande Prairie and Fort McMurray as well as the oil sands areas near Fort McMurray and the heavy oil areas near Cold Lake and Peace River. Electric utility service is also provided to one community in British Columbia and to two communities in Saskatchewan. YECL serves 19 communities in the Yukon Territory, including the capital city of Whitehorse, and NUY and NLD serve nine communities in the Northwest Territories, including the capital city of Yellowknife.

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

	2003		2002	
	Millions of Kilowatt Hours	%	Millions of Kilowatt Hours	%
Industrial	6,502	67	7,143	70
Commercial	1,729	18	1,655	16
Residential	982	10	963	9
Rural, REAs and other	555	5	463	5
Total	9,768	100	10,224	100

The aggregate population of the areas provided with electric utility service by ATCO Electric, NUY, NLD and YECL is approximately 438,000 and service is provided to approximately 202,000 customers. ATCO Electric has been assigned approximately 65% of the designated service area within Alberta which contains approximately 15% of the existing provincial electrical load and 12% of the existing population.

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

	2003		2002	
	Number	%	Number	%
Industrial	10,484	5	10,623	5
Commercial	27,386	14	27,448	14
Residential	135,263	67	131,143	66
Rural, REAs and other	29,135	14	28,632	15
Total	202,268	100	197,846	100

ATCO Electric, NUY, NLD and YECL own and operate extensive electric transmission and distribution systems. The systems consist of approximately 9,000 km of main transmission lines and 58,000 km of distribution lines. In addition, ATCO Electric delivers power to and operates approximately 12,300 km of REA-owned distribution lines.

ATCO Electric, NUY, NLD and YECL own and operate 36 diesel, natural gas turbine and hydro generating plants having an aggregate nameplate capacity of 62 megawatts in Alberta and in the Yukon and Northwest Territories. The maximum peak load demand for these plants during the year ended December 31, 2003, was 33 megawatts.

Electricity Supply

ATCO Electric is required to supply energy to certain customers in one of three ways: through the regulated rate tariff, as the default retailer or as the default supplier (formerly "supplier of last resort").

ATCO Electric is obligated to supply energy under the regulated rate option to the residential, farm and small commercial customers in its designated service area who do not choose an unregulated retailer. ATCO Electric purchases electricity from the AESO at spot prices to supply the regulated rate option customers, the costs for which are collected from customers at rates approved by the AEUB. In November 2003, the government of Alberta revised its regulations, effective January 1, 2004, and as a result, ATCO Electric will now be at risk for electric energy supply and will no longer be able to flow through the AESO price to customers. A further revision to the regulations in November permitted the AEUB to extend the period for implementation to July 1, 2004 upon application. In December 2003, the AEUB issued a decision approving ATCO Electric's application to extend the implementation date to July 1, 2004. Under the revised regulations, ATCO Electric is obligated to provide a fixed price regulated rate option to customers until July 1, 2006, and a regulated rate option based on actual spot prices thereafter.

ATCO Electric is also obligated to assign a default retailer for its customers who are not eligible for the regulated rate tariff and did not choose an unregulated retailer prior to 2001. ATCO Electric appointed itself as the default retailer and purchases electricity from the AESO at the spot price to supply these customers, the costs for which are passed on to customers on a dollar for dollar basis.

ATCO Electric has appointed itself as the default supplier (formerly "supplier of last resort") for its customers who are not eligible for its regulated rate tariff and who are unable to obtain service from a retailer. The energy procurement price for these customers is the spot price of the AESO, the costs for which are passed on to customers on a dollar for dollar basis.

Sale of Retail Operations

In December 2002, Direct Energy Marketing Limited ("Direct Energy") agreed to purchase the retail energy businesses of ATCO Gas and ATCO Electric, subject to the satisfaction of certain conditions, including the receipt of required regulatory approvals and the government of Alberta amending certain natural gas and electricity legislation. In December 2003, the AEUB issued decisions approving the transfer of the retail operations of ATCO Gas and ATCO Electric to Direct Energy, appointing Direct Energy provider of the natural gas Default Rate Tariff and electricity Regulated Rate Tariff in the ATCO Gas and ATCO Electric service territories and approving the tariff rate structure of Direct Energy Regulated Services, ATCO Gas and ATCO Electric. The City of Calgary has filed leave to appeal the AEUB decision approving the transfer of the retail operations. The Corporation is reviewing the AEUB decisions and certain other conditions which must be satisfied in order to close the sale of its retail business to Direct Energy.

If the sale does close on the anticipated terms, ATCO Gas and ATCO Electric will no longer be involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to provide transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and fair return. The sale does not include any of the distribution and transmission facilities used to deliver natural gas and electricity to customers.

In addition, ATCO I-Tek Business Services Ltd., which currently provides billing and customer care services to ATCO Gas and ATCO Electric, has entered into a contract to provide similar services to Direct Energy in the event the sale closes as anticipated (see "Technologies – ATCO I-Tek Business Services Ltd.").

Power Generation

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

Regulated

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

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

The name plate capacity ratings of Alberta Power (2000)'s generating plants are listed below.

Plant	Type of Generating Plant	Name Plate Capacity Rating (megawatts)	
Battle River	coal-fired steam turbine	679	
Sheerness	coal-fired steam turbine	375	(1)
H.R. Milner	coal-fired steam turbine	150	(2)
Rainbow	natural gas turbine	90	
Sturgeon	natural gas turbine	18	
		1,312	

Notes:
(1) Alberta Power (2000)'s ownership of the 750 megawatt name plate capacity.
(2) Alberta Power (2000) operated H.R. Milner to the closing date of its sale on January 29, 2004.

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

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

In 2001, Alberta Power (2000) and the Alberta Balancing Pool entered into an agreement which gave the Alberta Balancing Pool control of the H.R. Milner generating plant effective January 1, 2001 and the right to sell it until September 30, 2003, failing which the rights to control the generating plant would revert to Alberta Power (2000). In return, Alberta Power (2000) was paid $63.5 million, the net book value of the generating plant and coal inventory. Alberta Power (2000) operated the generating plant under a cost of service contract with the Alberta Balancing Pool. On August 6, 2003, the Alberta Balancing Pool announced that it had entered into an agreement for the sale of plant. Alberta Power (2000) extended its cost of service contract until January 29, 2004, when the plant was sold by the Alberta Balancing Pool to a third party. As part of the sale, Alberta Power (2000) was relieved of all decommissioning risk, including any environmental liabilities incurred while Alberta Power (2000) was operating the generating plant.

As a result of unprecedented drought conditions, the water level in the cooling pond used by the Battle River plant in its production of electricity had fallen to an all-time low in early 2003, and the Corporation made a force majeure claim in respect of short term curtailed plant production which was experienced during the first quarter of 2003. Water levels continue to be below normal levels, however sufficient water is currently available to permit the plant to produce electricity according to its PPA contractual requirements. The Corporation is preparing submissions for the arbitration hearings scheduled to commence May 3, 2004, in respect of the force majeure claim.

Non-Regulated

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

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

Location	Commissioning Date	Name Plate Capacity Rating	Ownership	Net Ownership
		(megawatts)		(megawatts)
Canada:				
Operating Units:				
McMahon, B.C.	1993	120	50.0%	60
Primrose, Alberta	1998	85	40.0%	34
Poplar Hill, Alberta	1998	43	80.0%	34
Rainbow Lake, Alberta	1999	89	40.0%	36
Joffre, Alberta	2000	480	32.0%	154
Valleyview, Alberta	2001	46	80.0%	37
Muskeg River, Alberta	2003	170	56.0%	95
Cory, Saskatchewan	2003	260	40.0%	104
Oldman River, Alberta	2003	32	80.0%	26
Scotford, Alberta	2003	170	80.0%	136
Units Under Construction:				
Brighton Beach, Ontario	2004	580	40.0%	232
United Kingdom:				
Operating Units:				
Barking, London	1995	1,000	25.5%	255
Heathrow Airport	1995	14	50.0%	7
Australia:				
Operating Units:				
Osborne, South Australia	1998	180	50.0%	90
Bulwer Island, Queensland	2001	33	50.0%	17
Total		3,302		1,317

Canada

ATCO Power has a 50% interest in a joint venture with McMahon Power Holdings L.P. The joint venture owns and operates the 120 megawatt McMahon cogeneration plant at Taylor, British Columbia. All of the electricity generated is sold to British Columbia Hydro and Power Authority ("BC Hydro") pursuant to an electricity purchase agreement expiring in 2013. In addition to generating electricity, the plant sells steam to Westcoast Energy Inc.'s adjacent natural gas processing plant.

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

ATCO Power operates a 43 megawatt natural gas-fired generating plant at Poplar Hill near Grande Prairie, Alberta. Revenues are derived from power sold to the AESO and from transmission deferral credits contracted with the AESO. ATCO Power owns an 80% interest in the project and ATCO Resources owns 20%.

ATCO Power operates an 89 megawatt natural gas-fired generating plant at Rainbow Lake, Alberta which sells steam and electricity to Husky Energy Inc. ("Husky"). Surplus electricity is sold to the AESO. ATCO Power owns a 40% interest in the project, ATCO Resources owns 10% and Husky owns 50%.

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

ATCO Power operates a 46 megawatt natural gas-fired generating plant near Valleyview, Alberta. All of the electricity produced by the plant is sold to the AESO. ATCO Power owns an 80% interest in the project and ATCO Resources owns 20%.

ATCO Power and SaskPower International Inc. ("SPI") are participants in a joint venture which operates a 170 megawatt natural gas-fired cogeneration plant and related facilities at the Athabasca Oil Sands Project ("AOSP") Muskeg River mine near Fort McMurray, Alberta. Approximately one-half of the electricity and all of the steam produced by the plant are supplied to AOSP for use in its Muskeg River mine. The balance of the electricity generated is sold to the AESO. Construction of the plant has been completed and commercial operation commenced on January 1, 2003. ATCO Power owns a 56% interest in the project, ATCO Resources owns 14% and SPI owns 30%.

ATCO Power and SPI are participants in a joint venture which operates a 260 megawatt natural gas-fired cogeneration plant at Potash Corporation of Saskatchewan Inc.'s Cory Mine, located near Saskatoon, Saskatchewan. ATCO Power is the operator of the facility. Saskatchewan Power Corporation purchases all of the electricity generated by the plant for 25 years. Construction of the plant has been completed and commercial operation commenced on January 15, 2003. ATCO Power owns a 40% interest in the project, ATCO Resources owns 10% and SPI owns 50%.

ATCO Power operates a 32 megawatt hydroelectric generating plant at the Oldman River dam near Pincher Creek, Alberta. All of the electricity produced by the plant is sold to the AESO. The project was commissioned on September 30, 2003. ATCO Power owns an 80% interest in the project and ATCO Resources owns 20%. The Piikani Nation of Brockett, Alberta has an option which expires May 31, 2005, to purchase a 25% interest in the project.

ATCO Power operates a 170 megawatt natural gas-fired cogeneration plant at the AOSP upgrader at Scotford, Alberta. Approximately 80% of the electricity and all the thermal energy produced by the plant is supplied to AOSP for use in the upgrader and the balance of the electricity is sold to the AESO. Construction of the plant has been completed and commercial operation commenced on December 1, 2003. ATCO Power owns an 80% interest in the project and ATCO Resources owns 20%.

A partnership formed by ATCO Power and Ontario Power Generation ("OPG") is constructing and will operate the Brighton Beach power plant, a 580 megawatt natural gas-fired combined cycle generating plant at the site of the former J.C. Keith Generating Station, near Windsor, Ontario. Coral Energy Canada Inc. has agreed to supply and pay for the natural gas to be used at the plant and will own, market and trade all the electricity produced. Construction is progressing with commercial operation scheduled for the summer of 2004. ATCO Power owns a 40% interest in the project, ATCO Resources owns 10% and OPG owns 50%. The estimated costs to complete the generating plant have increased from original estimates by approximately 19% to $562 million due to higher supply and assembly costs for the heat recovery steam generator, higher costs for civil works and changes in engineering scope. In addition, ATCO Power has provided a contingency of $10 million for unforeseen commissioning costs. ATCO Power's share is $230 million.

On September 8, 2003, SPI announced that it had selected ATCO Power as its joint venture partner to potentially develop up to 150 megawatts of wind generation power in Saskatchewan.

United Kingdom

ATCO Power and Balfour Beatty plc (formerly BICC plc), a United Kingdom construction group, each own a 50% equity interest in Thames Power, a London, England based company. Thames Power has a 51% interest in BPL which owns a 1,000 megawatt natural gas-fired combined cycle generating plant at Dagenham in London, England (the "Barking power plant"). EDF Energy (Energy Branch) plc (formerly London Power Company plc), SSE Energy Supply Limited (formerly Scottish and Southern Energy Limited), and TXU Europe Power Limited (the "Regional Electricity Companies") own the remaining 49% interest in BPL. The Regional Electricity Companies have entered into long term agreements expiring in 2010 to purchase all of the electricity produced at the plant. The Barking power plant is operated by ATCO Power.

On November 19, 2002, an administration order was issued by a United Kingdom court for TXU Europe Energy Trading Ltd. ("TXU Europe"), which had a long term offtake agreement for 27.5% of the power produced by the Barking power plant. An administration order is similar to a Chapter 11 bankruptcy filing in the United States. BPL has filed a claim with the Administrator and is working with the Administrator and Creditors' Committees on liquidation of TXU Europe and settlement of claims. The Barking power plant will continue to supply 725 megawatts of power under long term contracts. The 275 megawatts of power previously supplied to TXU Europe is being sold under short term bilateral agreements.

ATCO Power has a 50% interest in a joint venture with a subsidiary of EDF Energy plc (formerly London Electricity plc). The joint venture owns and operates a facility consisting of a

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

Australia

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

In December 2002, the joint venture was advised that FOT's parent corporation would no longer provide financial support to FOT. FOT continues to meet its obligations under its agreements with the joint venture. The government of South Australia has guaranteed the obligations of FOT under these agreements.

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

Logistics and Energy Services

Regulated Natural Gas Transportation

ATCO Pipelines is engaged in the business of transporting natural gas throughout Alberta.

ATCO Pipelines owns and operates extensive natural gas transportation systems. The systems consist of approximately 8,310 km of pipelines, 21 compressor sites and a salt cavern peaking facility. The systems have 203 producer receipt points, 77 interconnections with TransCanada Pipelines Limited, two interconnections with Alliance Pipeline and one interconnection with Many Islands Pipelines.

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

	2003	2002
	(terajoules/day)	
Contract Demand:		
Producer	1,314	1,463
Industrial	1,075	1,131
Distribution	39	39
Affiliates	2,171	2,257
Total	4,599	4,890
IT/OR/Variable Volumes:		
Producer	209	156
Industrial	231	135
Distribution	18	18
Total	458	309
Total Contract Demand and IT/OR/Variable Volumes	5,057	5,199

In addition, ATCO Pipelines provides sales service to certain customers. ATCO Pipelines obtains natural gas for these customers from ATCO Gas.

Non-Regulated Natural Gas Gathering, Processing and Storage Operations

ATCO Midstream owns and operates non-regulated gathering and processing facilities in Alberta. ATCO Midstream also provides management services for ATCO Gas' storage field at Carbon, Alberta and natural gas procurement services for ATCO Gas and other subsidiaries of the Corporation.

ATCO Midstream owns a 51.3% interest in EEEP. Located in south Edmonton, EEEP is a natural gas processing plant which extracts ethane and other natural gas liquids from natural gas flowing into the Edmonton market area. Ethane is sold to an Alberta ethylene producer under a long term contract that expires in December 2012 and other natural gas liquids are sold under annual contracts that are renewable every March 31.

ATCO Midstream owns or has a joint venture interest in 12 natural gas processing plants, eight of which it operates, three compression facilities, all of which it operates, and approximately 1,000 km of field gathering lines. Natural gas production from the producing properties connected to ATCO Midstream's natural gas gathering systems is processed by ATCO Midstream and either transported for a fee or purchased and sold under contracts with third parties.

ATCO Midstream has agreements for natural gas storage capacity with various facilities in Alberta. ATCO Midstream utilizes this capacity to provide storage services to third parties.

Technical Facilities Management

ATCO Frontec, through its own operations and through a number of joint ventures, provides project management and technical services for customers in the industrial, defence, telecommunications and transportation sectors. Activities include the operation and maintenance of the Alaska Radar System, the Solid State Phased Array Radar System, the Automatic Data Processing systems for the NATO Stabilization Force Headquarters in Sarajevo, and various remote sites for Northwestel Inc. in northern Canada. ATCO Frontec also provides airport operation and maintenance, security, facilities management, bulk fuel storage and distribution and a wide variety of services and business activities in various locations throughout Canada.

ATCO Frontec and Pan Arctic Inuit Logistics Corporation ("Pan Arctic") have a contract with the Government of Canada to operate and maintain the North Warning System until September 30, 2006. Nasittuq Corporation, a corporation jointly owned by ATCO Frontec and Pan Arctic, operates as agent for the purposes of the contract.

Technologies

ATCO I-Tek

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

ATCO I-Tek Business Services

ATCO I-Tek Business Services provides billing services, payment processing, credit, collection and call centre services. ATCO I-Tek Business Services provides contract utility billing and related services to the City of Red Deer pursuant to a five year contract which expired, and was not renewed, on December 31, 2003. Utility billing and related services are supplied to ATCO Gas and ATCO Electric pursuant to contracts expiring on January 1, 2007.

On December 12, 2002, ATCO I-Tek Business Services announced that it had entered into a 10 year contract with Direct Energy to provide billing and customer care services to nearly one million Alberta customers. Commencement of the contract is conditional upon the closing of the sale of ATCO Gas' and ATCO Electric's retail operations to Direct Energy (see "Business of the Corporation – Utilities – Sale of Retail Operations").

ASHCOR Technologies

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

ATCO Travel

ATCO Travel is engaged in the provision of travel services to corporate clients, the general public and the Corporation. ATCO Travel is one of the largest independent travel agencies in western Canada.

Genics

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

FRANCHISES

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

In Edmonton, distribution of natural gas is carried on under the authority of an exclusive franchise. AGP has entered into an agreement with the City of Edmonton for a 10 year renewal of the franchise to November 15, 2005. The franchise renewal is subject to the right of the City of Edmonton, at the end of the renewal period, to purchase all of AGP's assets within the city and its assets outside the city used in supplying natural gas to the city. The purchase price would be the amount of the actual value thereof as a going concern plus 10% of such value. Although the franchise agreement gives the City certain rights of purchase, since 1935 the City has granted renewals for 10 year periods.

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

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

GOVERNMENT REGULATION

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

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

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

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

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

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

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

				Rate of Return	
	Year	Date of Decision (1)	Mid-Year Rate Base ($ Millions)	Rate Base (%)	Common Equity (2) (%)
ATCO Electric					
Transmission	2003	Oct. 02/03	672.0 (3)	8.03 (3)	9.40
	2004	Oct. 02/03	474.8 (4)	(4)	(4)
Distribution	2003	Oct. 02/03	558.5 (5)	7.93 (5)	9.40
	2004	Oct. 02/03	584.5 (4)	(4)	(4)
ATCO Pipelines North	2003	Dec. 02/03	(6)	(6)	9.50
	2004	Dec. 02/03	(4)	(4)	(4)
ATCO Pipelines South	2003	Dec. 02/03	(6)	(6)	9.50
	2004	Dec. 02/03	(4)	(4)	(4)
ATCO Gas North	2003	Oct. 01/03	(7)	(7)	9.50
	2004	Oct. 01/03	(7)	(7)	9.50
ATCO Gas South	2003	Oct. 01/03	(7)	(7)	9.50
	2004	Oct. 01/03	(7)	(7)	9.50

Notes:

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

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

(3) Based on a common equity ratio of 32%. ATCO Electric, as directed by the AEUB, has refiled the 2003 and 2004 revenue requirements, incorporating the findings in the decision. The AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years on February 17, 2004.

(4) The 2004 rate of return on common equity and the common equity ratios for the ATCO Electric's transmission and distribution operations and ATCO Pipelines operations will be determined as part of the generic cost of capital hearing.

(5) Based on a common equity ratio of 35%. ATCO Electric, as directed by the AEUB, has refiled the 2003 and 2004 revenue requirements, incorporating the findings in the decision. The AEUB issued its final determination of the revenue requirements for the 2003 and 2004 test years on February 17, 2004.

(6) Based on a common equity ratio of 43.5%. ATCO Pipelines, as directed by the AEUB, has refiled the 2003 and 2004 revenue requirements, incorporating the findings in the decision. The AEUB has not yet issued its final determination of the revenue requirements and rate base for the 2003 and 2004 test years.

(7) Based on a common equity ratio of 37%. ATCO Gas, as directed by the AEUB, has refiled the 2003 and 2004 revenue requirements, incorporating the findings in the decision. The AEUB has not yet issued its final determination of the revenue requirements and rate base for the 2003 and 2004 test years.

Gas Utilities Act

Under the Gas Utilities Act, customers in Alberta have the choice of purchasing their natural gas supplies from their local natural gas utility or directly from retailers, subject to certain conditions.

Customers purchasing natural gas from ATCO Gas do so at rates that are approved by the AEUB. ATCO Gas receives no profit or benefit from increases in natural gas prices. The cost of the natural gas it purchases for sale to its customers is passed on directly to its customers following scrutiny in a public process under the authority of the AEUB. In October 2001, the AEUB approved the implementation on April 1, 2002, of a monthly method of adjusting customer rates to recover the cost of natural gas purchased for customers of ATCO Gas. The new methodology replaces the previous method under which rates were adjusted twice a year. The new methodology is intended to provide greater price transparency for customers.

In August 2002, the Government of Alberta announced changes to utility legislation designed to improve the environment for retail competition in the Province. Amendments to the Electric Utilities Act and Gas Utilities Act received Royal Assent in March 2003 and were proclaimed in force in June 2003. These changes were designed to bring customer choice for both gas and electricity into closer alignment, as well as to move towards consistent regulatory treatment of investor-owned and municipally-owned utilities.

In July 2003, ATCO Gas filed its compliance application in accordance with the new legislation.

In December 2003, the AEUB issued a decision approving the implementation of the "One Bill Model" no later than April 1, 2004. The One Bill Model will ensure that customers who choose to purchase their natural gas requirements from a retailer will receive only one bill for natural gas service. Previously, customers would receive a bill from the retailer for the purchase of the commodity and a separate bill from ATCO Gas for the delivery service.

Electric Utilities Act

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

It is anticipated that ATCO Electric's transmission and distribution activities will continue to be regulated by the AEUB and Alberta Power (2000)'s generation activities will continue to be regulated via legislatively mandated PPA's approved by the AEUB.

New Generation

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

Existing Generation

The EUA provided for the equalization of costs of "existing generation" that was in service at December 31, 1995. On January 1, 2001, existing generation became subject to legislatively mandated PPA's approved by the AEUB. The PPA's are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. The plants will become deregulated upon the expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the life of the related generating plant and December 31, 2020.

Transmission

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

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

Certain transmission expansion projects were to be procured by the AESO through a competitive bid process. The project costs were to be charged to the AESO through contracts between the winning bidder and the AESO. Following consultation with interested parties, the Alberta Department of Energy suspended this competitive bid process for awarding transmission expansion and subsequently eliminated the process in its recent transmission policy paper. The projects previously awarded under this process have been assigned to regulated entities at the direction of the Government of Alberta.

Distribution

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

Retail

On January 1, 2001, all customers had a choice as to the supplier of their electric energy. Industrial and large commercial customers were required to select a retailer effective January 1, 2001. Other customers may continue to purchase electricity from their current distribution utility under a regulated rate option. This option was originally to be available for five years (2001 – 2005) for residential and farm customers and for three years (2001 – 2003) for small commercial and small industrial customers. In November 2003, the government of Alberta revised its regulations to require distribution utilities to provide the fixed regulated rate option to July 1, 2006 for all eligible regulated rate option customers. After July 1, 2006, the distribution utilities are required to provide the regulated rate option to customers based on actual spot prices.

ATCO Electric is obligated to supply energy under the regulated rate option to the residential, farm and small commercial customers in its designated service area who do not choose an unregulated retailer. ATCO Electric purchases electricity from the AESO at spot prices to supply the regulated rate option customers, the costs for which are collected from customers at rates approved by the AEUB. In November 2003, the government of Alberta revised its regulations, effective January 1, 2004, and as a result, ATCO Electric will now be at risk for electric energy supply and will no longer be able to flow through the AESO price to customers. A further revision to the regulations in November permitted the AEUB to extend the period for implementation to July 1, 2004 upon application. In December 2003, the AEUB issued a decision approving ATCO Electric's application to extend the implementation date to July 1, 2004. Under the revised regulations, ATCO Electric is obligated to provide a fixed price regulated rate option to customers until July 1, 2006, and a regulated rate option based on actual spot prices thereafter.

Environmental Protection

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

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

The Corporation's operating subsidiaries do not expect that environmental protection laws and regulations will affect them differently from other companies in the industries in which they operate. Specifically identifiable expenditures for pollution abatement and control were approximately $17.4 million in 2003 and are estimated to be $14.7 million in 2004. Costs of compliance with existing laws and regulations are not expected to have a material impact on the earnings of the Corporation or the competitive position of the operating subsidiaries.

DIRECTORS AND OFFICERS

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

Name and Municipality of Residence	Position	Principal Occupation	Periods Served as a Director of the Corporation
B.M. Andrews Calgary, Alberta	Vice President	Vice President, Finance, ATCO I-Tek Inc.	
R.T. Booth (3) (4) Calgary, Alberta	Director	Partner, Bennett Jones LLP (barristers and solicitors)	1998 to date
W.L. Britton, Q.C. (2) Calgary, Alberta	Director and Vice Chairman of the Board	Partner, Bennett Jones LLP (barristers and solicitors)	1980 to date
J.A. Campbell Calgary, Alberta	Senior Vice President, Finance and Chief Financial Officer	Senior Vice President, Finance and Chief Financial Officer, Canadian Utilities Limited and ATCO Ltd.	
D.R. Cawsey Calgary, Alberta	Vice President, Human Resources and Corporate Secretary	Vice President, Human Resources and Corporate Secretary, Canadian Utilities Limited and ATCO Ltd.	
D.T. Davis Calgary, Alberta	Vice President, Internal Audit	Vice President, Internal Audit, Canadian Utilities Limited and ATCO Ltd.	
B.P. Drummond (2) (5) Montreal, Quebec	Director	Corporate Director	1997 to date
B.K. French (3) (4) Calgary, Alberta	Director	President, Karusel Management Ltd. (property management and management consultants)	1981 to date
L.A. Heathcott (5) Calgary, Alberta	Director	Executive Vice President, Spruce Meadows (international show jumping venue)	2000 to date
W.R. Horton (3) (4) Winfield, B.C.	Director	Corporate Director	1984 to date
S.W. Kiefer Calgary, Alberta	Vice President, Information Technology and Chief Information Officer	Vice President, Information Technology and Chief Information Officer and Managing Director, Technologies Business Group, Canadian Utilities Limited and ATCO Ltd.	

Name and Municipality of Residence	Position	Principal Occupation	Periods Served as a Director of the Corporation
W.A. Kmet Calgary, Alberta	Vice President	Managing Director, Industrials Business Group, ATCO Ltd.	
C.S. McConnell Calgary, Alberta	Treasurer	Treasurer, Canadian Utilities Limited and ATCO Ltd.	
H.M. Neldner (2) (3) (4) (5) Westerose, Alberta	Director	Corporate Director	1991 to date
L.R. Shaben Edmonton, Alberta	Director	Chairman, Western New Ventures Capital Corporation (venture capital corporation)	1995 to date
N.C. Southern Calgary, Alberta	Director, President and Chief Executive Officer	President and Chief Executive Officer, Canadian Utilities Limited and ATCO Ltd.	1990 to date
R. D. Southern, C.B.E., O.C., LL.D. Calgary, Alberta	Director and Chairman of the Board	Chairman of the Board, Canadian Utilities Limited and ATCO Ltd.	1977 to 1979 1980 to date
P. Spruin Calgary, Alberta	Assistant Corporate Secretary and Manager, Corporate Secretarial	Assistant Corporate Secretary and Manager, Corporate Secretarial, Canadian Utilities Limited and ATCO Ltd.	
D.L. Tait, F.R.I., F.C.A. (4) (5) Lethbridge, Alberta	Director	Partner, Meyers Norris Penny LLP (Chartered Accountants)	1992 to date
G.G. Tallman (3) Calgary, Alberta	Director	Corporate Director	2003 to date
L.J. Vegh, (5) Calgary, Alberta	Vice President, Insurance	Vice President, Insurance, Canadian Utilities Limited and ATCO Ltd.	
K.M. Watson Calgary, Alberta	Vice President, Finance and Controller	Vice President, Finance and Controller, Canadian Utilities Limited and ATCO Ltd.	
S.R. Werth Calgary, Alberta	Senior Vice President and Chief Administration Officer	Senior Vice President and Chief Administration Officer, Canadian Utilities Limited and ATCO Ltd.	

Name and Municipality of Residence	Position	Principal Occupation	Periods Served as a Director of the Corporation
C.W. Wilson (3) (4) Evergreen, Colorado	Director	Corporate Director	2000 to date

Notes:
(1) Each director holds office until the close of the annual meeting of shareholders of the Corporation.
(2) Member of the Corporate Governance – Nomination, Succession and Compensation Committee.
(3) Member of the Audit Committee.
(4) Member of the Risk Review Committee.
(5) Member of the Pension Fund Committee.

All of the directors and officers have been engaged for the last five years in the indicated principal occupations, or in other capacities with the companies or firms referred to, or with affiliates or predecessors thereof, with the exception of Mr. L.R. Shaben, who is President, Shaben World Enterprises Inc.; Ms. P. Spruin, who was a corporate consultant and prior thereto was Corporate Secretary, IPEC Ltd.; Mr. D.L. Tait, who is President, Tait Management Ltd.; Mr. G.G. Tallman, who was Senior Vice President, Prairies, Royal Bank of Canada and prior thereto was General Manager, Alberta, Royal Bank of Canada; and Mr. C.W. Wilson, who was Director, President and Chief Executive Officer of Shell Canada Ltd.

SHAREHOLDINGS OF DIRECTORS AND SENIOR OFFICERS

At December 31, 2003, the directors and officers of the Corporation, as a group, beneficially owned, directly or indirectly (via corporate holdings or otherwise), or exercised control or direction over approximately 73.8% of the outstanding Class B common shares of the Corporation.

MARKETS FOR THE SECURITIES OF THE CORPORATION

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

EMPLOYEE RELATIONS

At December 31, 2003, the Corporation and its joint ventures had the following number of employees:

	Number
Utilities	2,863
Logistics and Energy Services	978
Power Generation	463
Other	712
Sub Total	5,016
Joint Ventures – Logistics and Energy Services	970
Joint Ventures – Power Generation	263
Total	6,249

Approximately 3,600 employees are members of seven employee associations and 10 unions and are covered by 24 collective agreements. Seven of these agreements have expired and are under re-negotiation and the remaining 17 agreements expire over the period September 30, 2004 to September 30, 2007.

ADDITIONAL INFORMATION

Additional information, including executive compensation and principal holders of the Corporation's securities, is contained in the Corporation's Management Proxy Circular dated March 5, 2003. Additional financial information is provided in the Corporation's comparative financial statements for the financial year ended December 31, 2003.

The Corporation will provide to any person, upon request to the Vice President, Human Resources and Corporate Secretary of the Corporation at 1400 ATCO Centre, 909-11th Avenue S.W., Calgary, Alberta T2R 1N6 (telephone (403)292-7500 or fax (403) 292-7623):

(a) when the securities of the Corporation are in the course of a distribution under a preliminary short form prospectus or a short form prospectus,

(i) one copy of this Annual Information Form together with one copy of any document, or the pertinent pages of any document, incorporated by reference in this Annual Information Form,

(ii) one copy of the comparative financial statements of the Corporation for the financial year ended December 31, 2003 together with the accompanying report of the auditor and one copy of the most recent interim financial statements of the Corporation that have been filed, if any, for any period after the end of its financial year ended December 31, 2003,

(iii) one copy of the Corporation's Management Proxy Circular dated March 5, 2003, and

(iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, one copy of any of the documents referred to in (i) to (iii) above, provided the Corporation may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the Corporation.

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

CANADIAN UTILITIES LIMITED
An ATCO Company

Release

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

For Immediate Release

March 10, 2004

CANADIAN UTILITIES LIMITED

December 2003 Financial Statements & MD&A Available

CALGARY, Alberta – Canadian Utilities Limited today announced that its consolidated financial statements and management's discussion and analysis of financial condition and results of operations for the three months and year ended December 31, 2003 and its 2003 annual information form can be accessed on Canadian Utilities' website (www.canadian-utilities.com) or via SEDAR (www.sedar.com) or can be requested from the company.

The consolidated financial statements and management's discussion and analysis of financial condition and results of operations will be included in Canadian Utilities' 2003 Annual Report, which will be mailed to share owners on or about April 8, 2004, together with the notice of meeting and management proxy circular relating to Canadian Utilities' annual meeting of share owners, which will be held on May 12, 2004.

Canadian Utilities Limited is a part of the ATCO Group of companies. ATCO Group is an Alberta based corporation with a worldwide organization of companies engaged in Power Generation, Utilities, Logistics and Energy Services, Technologies and Industrials. More information about Canadian Utilities can be found on its website, www.canadian-utilities.com.

For further information contact:

J.A. (Jim) Campbell
Senior Vice President, Finance
& Chief Financial Officer
(403) 292-7502

K.M. (Karen) Watson
Vice President, Finance & Controller
(403) 292-7528