CU Inc.

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INFORMATION
FORM

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DEFINITIONS OF CERTAIN TERMS

Certain terms used in this Annual Information Form are defined below:

"AEUB" means the Alberta Energy and Utilities Board;

"ATCO" means ATCO Ltd.;

"ATCO Electric" means ATCO Electric Ltd. (formerly Alberta Power Limited);

"ATCO Gas" means the natural gas distribution operations of the Corporation;

"ATCO Pipelines" means the natural gas transmission operations of the Corporation;

"Corporation" means the Regulated Utility Subsidiaries prior to July 1, 1999, and thereafter means CU Inc. and its subsidiaries;

"CU" means Canadian Utilities Limited;

"CU Water" means CU Water Limited;

"CWNG" means Canadian Western Natural Gas Company Limited;

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

"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;

"NUL" means Northwestern Utilities Limited;

"NUY" means Northland Utilities (Yellowknife) Limited;

"petajoule" means a unit of energy equal to approximately 948.2 billion British thermal units;

"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;

"Regulated Utility Subsidiaries" means ATCO Electric, NUL, CWNG and CU Water;

"**YECL"** means The Yukon Electrical Company Limited.

All information in this Annual Information Form relating to periods prior to July 1, 1999, is based on the combined operations of the Regulated Utility Subsidiaries for such periods.

SELECTED FINANCIAL INFORMATION

Combined Five-Year Financial Summary

	1998	1997	1996	1995	1994
	(dollars in millions except for per share data)				
Revenues	1,556.8	1,579.9	1,491.8	1,430.3	1,547.2
Earnings attributable to Class A and Class B shares	155.3	151.6	144.9	139.3	133.8
Total assets	3,537.5	3,390.8	3,353.7	3,280.8	3,189.1
Long term debt, notes payable and retractable or redeemable preferred shares (2)	1,933.9	1,874.3	1,865.6	1,965.8	1,935.3
Dividends on Class A and Class B shares	82.3	99.3	67.9	88.2	104.4
Preferred share dividends per share:					
5 5/8% Cumulative Redeemable Preferred Shares (3)	-	4.45	5.63	5.63	5.63
4% Cumulative Redeemable Preferred Shares (4)	-	-	3.65	4.00	4.00
Cumulative Redeemable Preferred Shares 4% Series (4)	-	-	0.66	0.80	0.80
Cumulative Redeemable Preferred Shares 5 1/2% Series (4)	-	-	0.91	1.10	1.10
Series Second Preferred Shares:					
Series C (3)	-	1.68	1.83	1.83	1.83
Series I (5)	-	-	-	-	0.43
Series L (3)	-	1.61	1.93	1.93	1.93
Series M (5)	-	-	-	-	0.21
Series N (3)	-	1.49	1.78	1.78	1.78
Series P (3)	-	1.68	2.00	2.00	2.00
Series Q	1.48	1.48	1.48	1.48	1.48
Series R	1.33	1.33	1.33	1.33	1.17
Series S	1.65	1.65	1.65	1.65	0.41
Series U	1.16	1.18	-	-	-
Series V	1.17	0.29	-	-	-

Notes:

(1) There were no discontinued operations or extraordinary items during these periods.
(2) Given the appropriate market conditions, the redemption provisions can be expected to be exercised on all of the preferred shares of the Corporation.
(3) Redeemed on October 3, 1997.
(4) Redeemed on December 30, 1996.
(5) Redeemed on April 14, 1994.

Combined Quarterly Financial Summary

	Three Months Ended			
	December 31	September 30	June 30	March 31
	(unaudited, dollars in millions)			
1998				
Revenues	489.3	280.9	322.7	463.9
Earnings attributable to Class A and Class B shares (1) (2)	40.3	16.9	38.7	59.4
1997				
Revenues	417.8	285.6	321.5	555.0
Earnings attributable to Class A and Class B shares (1) (2)	39.3	25.9	31.6	54.8

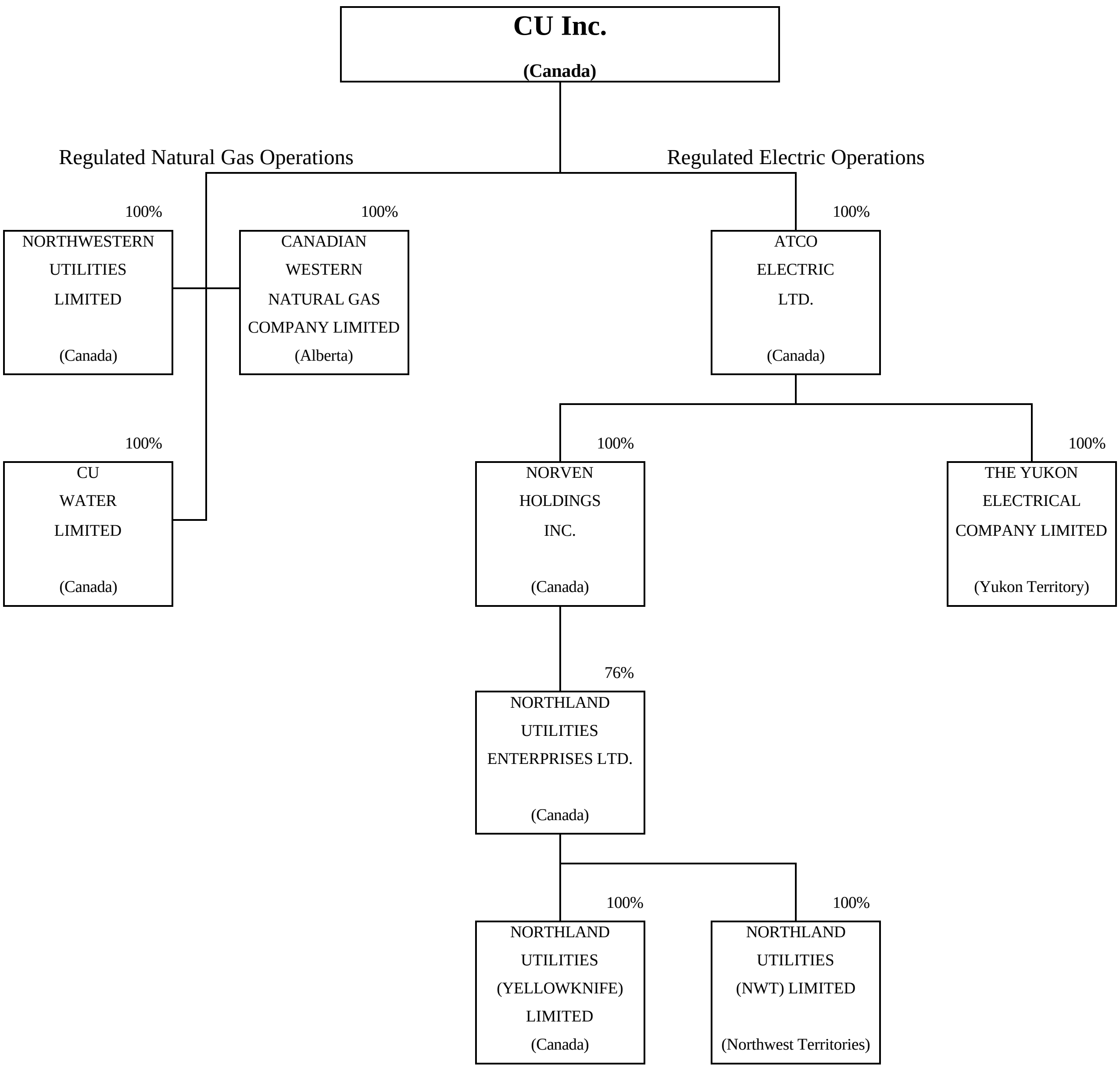
Notes:

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

(2) Due to the seasonal nature of the Corporation's operations and the timing of rate decisions, earnings for any quarter are not necessarily comparable or indicative of operations on an annual basis.

INTERCORPORATE RELATIONSHIPS

The following chart includes the names of the principal operating subsidiaries of CU Inc. at July 1, 1999, the jurisdictions under the laws of which they were organized and the percentages of their voting securities beneficially owned or over which control or direction was exercised by CU Inc. as at July 1, 1999.



Note:

(1) CU Inc. owns all of the non-voting shares of the principal operating subsidiaries, with the exception of the preferred shares which are owned by CU.

CU INC.

On May 12, 1999, the shareholders of CU approved a reorganization designed to separate the regulated utility operations of CU from its non-regulated operations. On July 1, 1999, the reorganization was implemented by the transfer of all of the common shares and debt of the Regulated Utility Subsidiaries to CU Inc. in return for common shares of CU Inc. and the assumption by CU Inc. of the obligations of CU under CU's existing trust indenture.

CU Inc. was incorporated under the laws of Canada on March 12, 1999. The address of the principal office of the Corporation is 1500 ATCO Centre, 909 - 11th Avenue S.W., Calgary, Alberta T2R 1N6.

BUSINESS OF THE CORPORATION

CU Inc. is a holding company. Its principal operating subsidiaries are engaged in natural gas and electric energy utility operations, primarily in Alberta.

The Corporation has two business segments: regulated natural gas operations and regulated electric operations. The Corporation's regulated natural gas operations include the production, gathering, purchase, transmission, transportation, storage, sale and distribution of natural gas and the transmission and distribution of water. The Corporation's regulated electric operations include the generation, transmission and distribution of electric energy.

Regulated Natural Gas Operations

The Corporation is engaged in the business of producing, gathering, purchasing, transmitting, transporting, storing, selling and distributing natural gas throughout Alberta and in the Lloydminster area of Saskatchewan. Although the Corporation is the major natural gas distributor in Alberta, certain areas are served by other natural gas utilities.

The Corporation's principal markets for the sale of natural gas are in the communities of Edmonton, Calgary, Airdrie, Camrose, Fort McMurray, Fort Saskatchewan, Grande Prairie, Lethbridge, Lloydminster, Red Deer, St. Albert, Sherwood Park, Spruce Grove and Wetaskiwin. The Corporation serves approximately 780,000 customers with natural gas, of whom approximately 76% are located in the 14 communities named above.

The Corporation owns and operates extensive natural gas production, transmission and distribution systems. The systems consist of approximately 860 km of field gathering lines, approximately 7,000 km of transmission lines connecting the sources of natural gas supply referred to under "Natural Gas Supply" to the communities served, and approximately 32,600 km of distribution mains. In addition, the Corporation owns modern service and maintenance facilities in major centres.

Sales and earnings of the Corporation's natural gas operations are affected by temperature and consequently winter weather can have a significant impact. Usually, more than 50% of the earnings of the Corporation's natural gas operations are generated during the months of January, February, November and December.

The amounts of natural gas sold and transported for each of the last two years were as follows:

	1998			1997		
	Sales	**Transportation**	**Total**	**Sales**	**Transportation**	**Total**
			(petajoules)			
Industrial	11.5	316.4	327.9	10.7	296.0	306.7
Commercial	91.4	1.4	92.8	92.8	1.2	94.0
Residential	99.9	-	99.9	99.7	-	99.7
Other	8.6	292.6	301.2	9.1	210.9	220.0
Affiliates	0.1	32.5	32.6	-	20.7	20.7
Total	211.5	642.9	854.4	212.3	528.8	741.1

In 1998, transportation services accounted for approximately 75% of the total volume of natural gas shipped by the Corporation.

Franchises

The Corporation distributes natural gas 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. The Corporation 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 the Corporation'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 the Corporation 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 have been granted for periods of up to 20 years. These franchises are exclusive to the Corporation and are renewable by agreement for further periods not exceeding 20 years each. If any franchise is not renewed, it remains in effect until such time as either party, with the approval of the AEUB, 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 established by the AEUB.

Natural Gas Supply

The Corporation purchases the major portion (approximately 65%) of its supplies of natural gas under contracts with terms of less than five years. 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 long 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 the Corporation's long term natural gas purchase contracts expire, the Corporation replaces them with one to five year contracts. 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. Additional natural gas requirements are obtained from the Corporation's producing properties. The Corporation also utilizes salt cavern and field storage of natural gas for balancing system supply and demand.

The Corporation estimates that at December 31, 1998, it had under long term contract 404 petajoules (approximately 374 Bcf) in the form of proved natural gas reserves in fields from which it purchases natural gas. The Corporation pursues a program involving the development of existing natural gas properties and supplies. The Corporation estimates that at December 31, 1998, it owned 435 petajoules (approximately 402 Bcf) of proved natural gas reserves.

In the opinion of the management of the Corporation, 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 1998, approximately 430 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 140 commercial water haulers. The operations of CU Water are subject to regulation by the AEUB.

Regulated Electric Operations

The Corporation is engaged in the business of generating, transmitting and distributing electric energy to 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, two communities in Saskatchewan, 19 communities in the Yukon Territory, including the capital city of Whitehorse, and nine communities in the Northwest Territories, including the capital city of Yellowknife.

Electricity sales to the various classes of customers for each of the last two years were as follows:

	1998		1997	
	millions of kilowatt hours	**%**	**millions of kilowatt hours**	**%**
Industrial	7,294	71	7,222	71
Commercial	1,541	15	1,484	15
Residential	880	9	873	9
Rural, REAs and other	473	5	510	5
Total	10,188	100	10,089	100

The aggregate population of the areas provided with electric utility service is approximately 440,000 and service is furnished to approximately 186,000 customers. The Corporation has been assigned approximately 65% of the designated service area within Alberta which contains approximately 20% of the existing provincial electrical load and 13% of the existing population.

The Corporation owns and operates extensive electric transmission and distribution systems. The systems consist of approximately 8,400 km of main transmission lines and 46,900 km of distribution lines. In addition, the Corporation provides power to and operates approximately 16,000 km of REA-owned distribution lines.

Franchises

The Corporation distributes electric energy in incorporated communities under the authority of franchises and in rural areas under approvals, permits or orders issued pursuant to applicable statutes.

The franchises under which service is provided in incorporated communities in Alberta have been granted for periods of up to 20 years. These franchises are exclusive to the Corporation and are renewable by agreement for further periods not exceeding 20 years each. If any franchise is not renewed, it remains in effect until such time as either party, with the approval of the AEUB, terminates it on six months written notice. Upon termination the municipality may purchase the facilities used in connection with that franchise at a price to be agreed upon or, failing agreement, to be established by the AEUB.

Generating Plants

At December 31, 1998, the Corporation owned 65 generating plants having a total name plate capacity of 1,387 megawatts. The maximum peak load demand during the year ended December 31, 1998, was 1,434 megawatts. The five largest plants are listed below. The 60 smaller plants are located throughout the more remote areas of Alberta, the Yukon Territory and the Northwest Territories.

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	
Rainbow	natural gas turbine	90	
Sturgeon	natural gas turbine	18	
Various (60)	diesel, natural gas turbine and hydro	75	
		1,387	

Note:
(1) The Corporation's entitlement to the 750 megawatt name plate capacity.

The Corporation manages the Sheerness generating plant and has entered into agreements with TransAlta Utilities Corporation for the equal sharing of ownership, cost and entitlement to electric capacity.

The Corporation owns or has committed under long term contracts sufficient coal supplies for the anticipated lives of its coal-fired generating plants.

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

The following discussion and analysis of financial condition and results of operations for the years ended December 31, 1998 and 1997 should be read in conjunction with the audited combined financial statements and related notes of the Regulated Utility Subsidiaries.

The audited combined financial statements have been prepared by combining the audited financial statements of the Regulated Utility Subsidiaries (refer to Note 1 to the audited combined financial statements). Transactions between segments have been eliminated in all reporting of the combined financial information.

Results of Operations

Combined Operations

Segmented revenues and earnings attributable to Class A and Class B shares for the years 1997 and 1998 were as follows:

	Revenues		Earnings	
	1998	1997	**1998**	1997
	(Millions of Canadian Dollars)			
Regulated natural gas operations	**882.1**	916.2	**68.7**	67.3
Regulated electric operations	**676.1**	665.1	**86.5**	84.2
Intersegment eliminations	**(1.4)**	(1.4)	**0.1**	0.1
Combined	**1,556.8**	1,579.9	**155.3**	151.6

Interest expense for 1998 increased by $3.7 million to $141.2 million. This increase was primarily due to new financing in natural gas operations, partially offset by the refinancing of maturing debt at lower rates.

Dividends on retractable preferred shares for 1998 decreased by $0.6 million to $18.0 million primarily as a result of the redemption of $68.1 million of retractable preferred shares on December 1, 1998. Dividends on non-retractable equity preferred shares for 1998 decreased by $2.0 million to $6.4 million primarily as a result of the redemption and refinancing of $109.5 million of non-retractable equity preferred shares at lower dividend rates in October 1997, partially offset by a reclassification of $56.9 million of retractable preferred shares to non-retractable equity preferred shares on December 1, 1998.

Income taxes for 1998 increased by $10.4 million to $156.8 million. The increase was primarily due to higher earnings before income taxes.

Regulated Natural Gas Operations

Earnings from regulated natural gas operations for 1998, which amounted to 44.3% of combined earnings of the Corporation, increased by $1.4 million to $68.7 million. Temperatures in 1998 were 3.2% warmer than normal, whereas temperatures in 1997 were 1.0% warmer than normal.

Revenues in 1998 decreased by $34.1 million to $882.1 million. The primary reason for the decrease was lower natural gas supply costs recovered in customer rates, lower sales per customer, and the impact of warmer temperatures which were 1.3% warmer than in 1997, partially offset by customer growth.

Operating expenses for 1998 decreased by $46.8 million to $613.1 million. This decrease was primarily due to lower natural gas supply costs. These costs decreased primarily due to lower natural gas prices, lower sales per customer and warmer weather. These decreased costs were partially offset by customer growth. The amount of natural gas supply costs recorded as an expense is based on the forecast cost of natural gas included in customer rates. Any variances from forecast are deferred until the AEUB approves revised rates to either refund or collect the variance. As a consequence, changes in natural gas supply costs have a negligible effect on the Corporation's earnings.

Regulated Electric Operations

Earnings from regulated electric operations for 1998, which amounted to 55.7% of combined earnings of the Corporation, increased by $2.3 million to $86.5 million.

Revenues in 1998 increased by $11.0 million to $676.1 million. This increase was primarily the result of higher sales to the Alberta power pool and higher industrial sales, mainly in the oilfield sector, partially offset by higher refunds to customers resulting primarily from the 1998 negotiated settlement for ATCO Electric.

Operating expenses for 1998 increased by $2.2 million to $297.9 million. The increase was primarily due to higher maintenance costs and higher costs of fuel and purchased power, partially offset by lower general and administrative costs.

Fuel costs in ATCO Electric are mostly for coal supply. To protect against volatility in coal prices, ATCO Electric owns or has committed under long term contracts sufficient coal supplies for the anticipated lives of its coal-fired generating plants. These contracts are at prices that are either fixed or indexed to inflation.

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 debt, preferred shares and common equity. Short term borrowings and short term bank loans are used to provide flexibility in the timing and amounts of long term financing.

Cash flow from operations increased by $17.7 million to $353.1 million in 1998. Investing increased from $242.2 million in 1997 to $243.5 million in 1998. Investment in property, plant and equipment decreased by $1.5 million to $273.3 million in 1998.

To finance 1998 operations, including the redemption of $51.7 million of long term debt having interest rates ranging from 8.37% to 12.00% and $68.1 million of preferred shares having a dividend rate of 5.90%, the Corporation incurred $164.7 million of short term borrowings from CU and incurred $20.0 million of bank borrowings.

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

On February 10, 1999, Dominion Bond Rating Service Limited ("DBRS") announced it had assigned preliminary ratings on the Corporation's long term debt and commercial paper at AA (low) and R-1 (middle), respectively. On July 5, 1999, CBRS Inc. ("CBRS") announced it had assigned ratings on the Corporation's debentures, commercial paper and preferred shares at A+, A-1(High) and P-1, respectively, and that the outlook on the Corporation's securities is negative. CBRS indicated that the negative outlook primarily reflects the uncertainty related to the proposed change from traditional rate of return regulation to the power purchase arrangements and the evolving dynamics of the energy industry which may introduce some volatility in the Corporation's overall earnings and coverage ratios in the future.

Future income tax liabilities of $57.4 million at December 31, 1998, 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.

Business Risks

The Corporation's operations are subject to the normal risks faced by regulated companies. These risks include the approval by the AEUB of customer rates which 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.

The business risks of ATCO Electric have changed with the implementation of the EUA in 1996. The risks include increased forecast risk as each electric utility is exposed to the forecasts of other electric utilities in Alberta as well as the requirement to independently forecast province-wide generation output and pool prices. These risks have been mitigated in the 1999 negotiated settlement for ATCO Electric by the implementation of deferral accounts for pool transactions. For generation, these accounts permit the deferral of 100% of the variations from forecast pool prices and 90% of the variations from forecast volumes. For distribution, these accounts permit the deferral of 100% of the variations from forecast pool prices. The balances in these deferral accounts at the end of 1999 and 2000, respectively, will be passed to customers.

There will be further changes in the electric utility industry in Alberta. Through legislation passed in 1998, the government of Alberta has set a timetable to pursue a direction, similar to that developing in other jurisdictions, whereby generation is completely deregulated and retail competition is available. This will result in changes to ATCO Electric's business risk, both at the generation level and in the distribution and retail businesses.

Hedging

It is the policy of the Corporation to use financial instruments to reduce specific risk exposures and not to hold these instruments for trading purposes.

The Corporation has entered into several contracts in order to reduce interest rate, foreign exchange and commodity price risk. The financial impact of these contracts is not material and the counterparty in each transaction is a major financial institution or a significant industry participant.

GOVERNMENT REGULATION

The operations of the Corporation in Alberta 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 and a fair return on rate base, 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. Costs of service include estimated operating expenses, depreciation and taxes.

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.

In Alberta, the level of AEUB involvement in the review process may diminish in the future as negotiations between utilities and their customers become more frequent.

The 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 three principal subsidiaries of the Corporation are as follows:

				Rate of Return	
	Year	**Date of Decision (1)**	**Mid-Year Rate Base**	**Rate Base**	**Common Equity (2)**
			($ millions)	(%)	(%)
ATCO Electric	1999	May 10/99	(3)	(3)	(3)
	2000	May 10/99	(3)	(3)	(3)
CWNG	1992	Feb. 8/93	428.6	8.87	12.25
	1993	Feb. 8/93	467.7	8.81	12.25
NUL	1997	Oct. 30/97	(4)	(4)	(4)

Notes:

(1) Indicates original date of decision, however the information shown reflects all amending or varying orders.

(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) A negotiated settlement approved by the AEUB is not expected to have a material impact on earnings. In the decision, the AEUB did not establish a rate base or a return on rate base.

(4) A negotiated settlement approved by the AEUB resulted in no change to customer rates for 1997. In the decision, the AEUB did not establish a rate base or a return on rate base.

On October 30, 1997, the AEUB approved, among other things, a five year agreement for NUL which changed rates for industrial and producer transportation customers and terms and conditions of service effective January 1, 1998. This agreement enhanced NUL's transmission service by reducing transmission costs. A similar agreement for CWNG was approved on an interim basis effective February 1, 1999, to December 31, 2002.

On March 31, 1998, the AEUB approved a five year negotiated settlement for NUL which would establish cost of service rates and terms and conditions of service for residential, commercial and institutional customers for 1998 through 2002.

At the request of the AEUB, CWNG conducted negotiations during 1998 to review CWNG's 1997 capital structure and return on common equity and to establish customer rates for 1998. As these negotiations did not result in a settlement, CWNG filed a General Rate Application. Hearings concluded in March 1999 and the AEUB has not issued a decision to date.

On June 16, 1998, NUL and CWNG announced that the operations of the two companies are to be merged and then restructured into two new businesses, one of which would focus on transmitting natural gas throughout Alberta through high pressure pipelines, the other of which would distribute natural gas to industrial, commercial and residential customers, primarily in urban areas. The restructuring is subject to AEUB approval. Hearings to consider the restructuring were held in February 1999. To date, the AEUB has not announced a decision.

As a result of the restructuring announcement, the negotiated settlement with NUL's residential, commercial and institutional customers was re-opened and a new agreement was reached for the same period as the original agreement through 2002. The AEUB approved the new agreement effective January 1, 1999.

On October 30, 1998, ATCO Electric filed a General Tariff Application with the AEUB for the 1999 and 2000 test years. Hearings for the tariff application were scheduled to be held in the second quarter of 1999. However, negotiations between ATCO Electric and its customers continued during this time and the parties were successful in reaching a negotiated settlement covering substantially all of the matters raised in the General Tariff Application. The negotiated settlement was approved by the AEUB on May 10, 1999, and the General Tariff Application was withdrawn. The matters not covered in the negotiated settlement are anticipated to be resolved in 1999 through separate AEUB hearings. The negotiated settlement, as well as the resolution of the matters yet to be resolved, are not expected to have a material impact on earnings.

In March 1997, ATCO Electric experienced an outage at two 30 megawatt generating units at its Battle River generating station. These two units have remained out of service since that outage and on January 11, 1999, the AEUB granted ATCO Electric's application to discontinue operation and dismantle these two units. ATCO Electric expects dismantling of the units to be completed by December 31, 1999, with no material impact on earnings.

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 producers or brokers, subject to certain conditions. In any case, the local natural gas utility provides the transportation and distribution services for all customers under AEUB approved tariffs which provide for the recovery of the cost of service and a fair return on rate base.

Customers purchasing natural gas from the Corporation do so at rates that are approved by the AEUB. The Corporation receives no profit or benefit from natural gas supply costs. The cost of 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. The Corporation is required to file an application with the AEUB to adjust customer rates whenever the difference between natural gas costs and cost recoveries from customers exceeds levels set by the AEUB. Customer rates proposed by the Corporation are scrutinized in public hearings which allow intervenors and the AEUB to test the prudence of the Corporation's natural gas purchases and resulting costs.

Electric Utilities Act

The EUA, as amended in 1998, provides the framework for a new structure in Alberta's electric utility industry and introduces competition into the electric utility business. In the amendments adopted, the government of Alberta has set a timetable to pursue a direction, similar to that developing in other jurisdictions, whereby generation is completely deregulated and retail competition is available. Both of these are to be in place beginning January 2001. Significant competition in generation will occur before 2001 as plants are retired and new generation is required to be built. Additional adjustments are being made to the operations of the power pool established by the EUA and in the implementation of open access transmission. New retail rates are being designed to reflect the new structure provided by the EUA.

It is anticipated that ATCO Electric's transmission and distribution activities will continue to be regulated. ATCO Electric, along with other industry participants, continues to be involved in discussions with the government of Alberta regarding the details of this deregulation process.

New Generation

Under the EUA, new generation assets 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 electric energy through the power pool.

Existing Generation

The EUA provides for the continued equalization of costs of existing generation that was in service at December 31, 1995. The equalization is currently achieved by providing for each entitled distributor a stipulated share of the output from each existing generating unit at regulated prices. If the actual pool prices paid by the distributors exceed the entitled prices, the owners of the existing generating units must pay the difference to the distributors. In return, the distributors are obligated to pay the fixed costs associated with the existing generating units in proportion to their share of the output. This system will end in 2000. Beginning in 2001, existing generation will be deregulated through a system of long term power purchase arrangements ("PPAs"). PPAs are commercial arrangements which will be imposed on generation owners and will be auctioned to a new group of participants known as "marketers". The effect of these arrangements will be that the marketers, not generation owners, will be the pool market participants for existing generation. The resulting risk to generation owners is uncertain at this time, as the exact form of PPA is still being developed, under the direction of the Department of Energy of the government of Alberta.

Transmission

Under the EUA, separate wholesale tariffs for transmission must be approved by the AEUB. The transmission tariffs allow any owner of a regulated or non-regulated generating unit to have access to the transmission systems of Alberta's utilities and thus facilitate the sale of its power to the distribution utilities in the province. The same transmission tariff is charged to each distribution utility regardless of location.

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

Distribution

Under the EUA, separate retail rates for distribution must be approved by the AEUB. Costs of distribution are not equalized. All owners of electric distribution systems must buy electric energy through the power pool. The power pool functions as a spot market, matching demand with supply to establish an hourly pool price. The power pool is operated by the Power Pool Administrator, and the Power Pool Council oversees the operation of the pool. The role of the Power Pool Council is to ensure fair and open competition for the exchange of electric energy. The Power Pool Council's membership is independent of market participants, including utilities.

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' facilities have 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 deleterious 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 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, the Corporation carries insurance 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 \$9.4 million in 1998 and are estimated to be \$11.0 million in 1999. 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.

EMPLOYEE RELATIONS

At December 31, 1998, the Corporation had the following number of employees:

	Number
Regulated natural gas operations	1,944
Regulated electric operations	1,365
Total	3,309

Approximately 2,560 employees are members of five employee associations and are covered by seven collective agreements, four of which expire December 31, 1999, and three of which expire December 31, 2001.

YEAR 2000

The Year 2000 problem results from the practice of using only two digits to represent a year, i.e., 98 is used instead of 1998. When a computer sees 00 as the year, it may not know whether that represents the year 1900 or 2000. Incorrect calculations may result or the program logic may refuse to accept the date and simply stop. This problem is not limited to accounting related applications running on computers. Millions of computer chips that utilize dates have been installed in electronic devices of all types and there is the potential that some of these devices may fail to handle the "00" year correctly. The interconnected nature of computers and electronic devices compounds the problem and increases both the probability and impact of failures.

Like other companies, the Corporation is vulnerable to the failure of its computerized systems and those of its key business partners, such as customers, suppliers, other utilities, government agencies and other third parties. Computers, information technology and electronics are used widely throughout the Corporation to facilitate effective and efficient operations and administration. Most operations systems are industry standard, while many administrative systems have been developed, and are supported, by internal staff.

The Corporation has been working on its Year 2000 Project since 1995. Each subsidiary of the Corporation manages its own Year 2000 project and a Year 2000 Program Manager, who reports directly to the President, has been appointed in each subsidiary. The Corporation has dealt with the Year 2000 issue in a methodical and systematic way, incorporating the following elements into its Year 2000 Project:

Awareness: Informing and educating management and employees about the meaning and scope of the Year 2000 issue;

Identification: Listing all systems and devices potentially affected by the Year 2000 date change;

Assessment:	Evaluating the importance of each system and device and determining the need for retirement, replacement or repair. A critical and high priority status is assigned to any system which affects the safe and reliable supply of services and products to the Corporation's customers. The remaining systems, which would impact on efficiency, are evaluated as medium or low priority;
Remediation / Testing:	Repairing or replacing impacted systems and devices on a priority basis as necessary. Tests are performed in compliance with established testing guidelines to ensure consistency of results;
Implementation:	Integrating the corrected systems and devices into normal production operations;
Clean Management:	Monitoring that systems and devices that have been declared Year 2000 ready are protected from changes that may result in the loss of certification as Year 2000 ready;
Audit / Verification:	Engaging independent experts to validate progress, results and conclusions;
	Participating and co-operating with the information technology industry, natural gas and electric industries, and various regulatory and government agencies for review of preparedness measures and contingency planning;
	Evaluating business relationships for Year 2000 responsibility and critically assessing the compliance and readiness efforts of key suppliers and customers;
Business Continuity:	Reviewing business processes and completing an impact/risk analysis of Year 2000 issues;
	Developing mitigation and contingency plans to deal with potential disruptions in the Corporation's businesses and to address uncertainties regarding key suppliers, business partners and infrastructure.

Activities undertaken across the Corporation include:

- A common definition for the term "Year 2000 Ready" has been established and is being enforced. As well, test guidelines for applications and hardware have been developed and implemented.

- Year 2000 warranty clauses have been included in all new purchase orders and contracts.

- Vendors have been requested to confirm that they will be able to maintain their current level of service after January 1, 2000.

- Key suppliers, customers and business partners have been consulted in an effort to minimize the risk of unexpected problems.

- Reviews of business continuity plans have been conducted and contingency plans have been co-ordinated with industry partners to address possible disruptions caused by unexpected Year 2000 failures from internal and external sources.

- Year 2000 project managers have been appointed for each of the Corporation's subsidiaries, with each project team reporting its progress to senior executives of that company on a monthly basis.

For the Corporation, Year 2000 readiness means that systems or devices have been remediated or replaced and tested as functional, or the ability to work around the system has been established. Year 2000 readiness also includes the preparation of contingency plans to deal with unforeseen impacts.

The Corporation is currently on schedule with its remediation efforts. As of April 30, 1999, the milestone of Year 2000 "readiness" for critical and high-priority systems was achieved. Progress continues to be made on medium / low priority systems, which are scheduled to be ready by July 30, 1999. This schedule will allow time for additional testing and co-ordination of key supplier and industry partners' plans prior to the end of 1999.

The target dates for Year 2000 readiness are based on the information currently available to the Corporation. The existing readiness plans and readiness dates for each company are subject to change.

The Corporation is involved in the supply of both natural gas utility services and electric utility services. A disruption in these services is of particular concern because of the potential impact to customers. The Corporation takes very seriously the issues that arise from the Year 2000 problem and its utility operations have been, and continue to be, committed to the reliable supply of electric and natural gas services.

The objective of the Corporation's Year 2000 Project is to minimize the likelihood of any problems with the reliability of services and to prepare for a prompt and appropriate response should a disruption occur. The subsidiaries of the Corporation have committed significant resources to the Year 2000 problem and have undertaken a number of precautions including:

- In ATCO Electric, the clocks on the control systems at all six coal-fired generating stations were advanced to December 31, 1999 and allowed to roll over to the new century. No problems were encountered. The clocks on the electrical transmission system were advanced in a similar manner. No problems were encountered and all of the Corporation's transmission and transmission control systems are now operating in the Year 2000.

- In ATCO Gas and ATCO Pipelines, integrated testing of systems has been conducted with clocks running through the change to the year 2000 as well as other key date changes. Clocks were rolled forward on all receipt and delivery points on the pipeline system, compressor stations, control and communications systems. No problems were encountered.

- Co-operation and sharing of information is established and ongoing with key suppliers, customers, industry associations and various government agencies to minimize the potential of an interruption in service.

- Contingency planning is an established and ongoing effort within the Corporation to address many types of operating disruptions, including acts of nature. The Corporation's operations are particularly focused on supplementing existing plans for Year 2000 related interruptions for all critical and high priority systems. These contingency plans include:

    - manual control procedures are in place and are being tested

    - additional employees will be at key field locations and the remaining staff will be on standby during critical time frames

    - additional supplies will be put in place to meet shortfalls that may arise as a result of supplier failure

    - procedures are in place to maximize the generating and reserve levels and to minimize the tie line loadings.

This activity is closely tied to the efforts to assess the overall readiness of the Corporation's computerized systems, equipment and business processes and their dependencies on and vulnerabilities to key third party business partners.

Due to the complexity of the Year 2000 issue, including the Corporation's dependence on third parties for important products and services, there can be no assurances that the Year 2000 remediation efforts by the Corporation or of such third parties will be completely successful. The impact of a failure to complete such remediation efforts successfully could have a material adverse effect on the results of operations and financial condition of the Corporation. While there can be no guarantees that disruptions will not occur, based on the approach taken by the Corporation and its understanding of the work done by third parties, the Corporation does not expect widespread or extended interruptions in its businesses or services.

The Corporation has taken the approach of attributing only incremental costs unique to the Year 2000 issue to its program costs. As a result, normal replacement of equipment and software has been excluded from Year 2000 costs even if its replacement is coincidental with the Year 2000 remediation. Consequently, the Corporation's costs for Year 2000 are not considered to be material and are expected to be approximately $10.8 million. The majority of these costs will extend the service life of the assets and, therefore, it is expected that these costs will be capitalized. The Corporation’s Year 2000 cost estimate is based on management’s current estimates which are derived from utilizing numerous assumptions of future events and are subject to change.

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**
W.L. Britton, Q.C. (1) Calgary, Alberta	Director	Partner, Bennett Jones (barristers & solicitors)
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	Assistant Corporate Secretary	Assistant Corporate Secretary and Manager, Human Resources, Canadian Utilities Limited and ATCO Ltd.
B.K. French (1) Calgary, Alberta	Director	President, Karusel Management Ltd. (property management and management consultants)
P.J. House Calgary, Alberta	Vice President, Corporate Secretary	Vice President, Corporate Secretary, Canadian Utilities Limited and ATCO Ltd.
C.S. McConnell Calgary, Alberta	Treasurer	Treasurer, Canadian Utilities Limited and ATCO Ltd.
N.C. Southern (1) Calgary, Alberta	Director, Deputy Chairman of the Board and Deputy Chief Executive Officer	Deputy Chairman of the Board and Deputy Chief Executive Officer, Canadian Utilities Limited and ATCO Ltd.
R.D. Southern, C.B.E., C.M., LL.D. Calgary, Alberta	Director, Chairman of the Board and Chief Executive Officer	Chairman of the Board and Chief Executive Officer, Canadian Utilities Limited and ATCO Ltd.

Name and Municipality of Residence	**Position**	**Principal Occupation**
C.O. Twa Calgary, Alberta	Director, President and Chief Operating Officer	President and Chief Operating Officer, Canadian Utilities Limited and ATCO Ltd.
K.M. Watson Calgary, Alberta	Vice President, Controller	Vice President, Controller, Canadian Utilities Limited and ATCO Ltd.
S.R. Werth Calgary, Alberta	Vice President, Administration	Vice President, Administration, Canadian Utilities Limited and ATCO Ltd.

Notes:
(1) Member of the Audit Committee.
(2) All directors were appointed March 12, 1999.
(3) Each director holds office until the close of the annual meeting of shareholders of the Corporation.

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 Ms. N.C. Southern, who was Executive Vice President, Spruce Meadows.

SHAREHOLDINGS OF DIRECTORS AND SENIOR OFFICERS

At July 12, 1999, the directors and officers of CU Inc., as a group, beneficially owned, directly or indirectly (via corporate holdings or otherwise), or exercised control or direction over all of the outstanding shares of CU Inc.

EXECUTIVE COMPENSATION

The officers of CU Inc. were appointed on March 12, 1999, the date of its incorporation. Accordingly, information regarding compensation of the officers is not available for periods prior to March 12, 1999.

R.D. Southern, N.C. Southern, C.O. Twa and J.A. Campbell have been executive officers of CU for each of the years in the three year period ended December 31, 1998. Information regarding their compensation as executive officers of CU is provided on pages 11 to 17 of the information circular of CU dated March 19, 1999, relating to the annual and special meeting of shareholders of CU held on May 12, 1999.

MARKETS FOR THE SECURITIES OF CU INC.

None of CU Inc.'s shares are listed on any exchange or similar market for securities.

AUDITOR

On June 21, 1999, PricewaterhouseCoopers LLP, 1200, 425 - 1 Street S.W., Calgary, Alberta T2P 3V7, was appointed the auditor of CU Inc.

ADDITIONAL INFORMATION

CU Inc. will provide to any person, upon request to the Vice President, Corporate Secretary of CU Inc. at 1500 ATCO Centre, 909 - 11th Avenue S.W., Calgary, Alberta T2R 1N6 (telephone (403) 292-7500 or fax (403) 292-7643):

(a) when the securities of CU Inc. are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities,

  (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 year ended December 31, 1998, together with the accompanying report of the auditor and one copy of any interim financial statements of the Corporation subsequent to the financial statements for the year ended December 31, 1998, and

  (iii) 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) or (ii) above; or

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

Information relating to ATCO or CU may be obtained upon request from the Vice President, Corporate Secretary of ATCO or CU at 1500 ATCO Centre, 909 - 11th Avenue S.W., Calgary, Alberta T2R 1N6 (telephone (403) 292-7500 or fax (403) 292-7643).

COMBINED FINANCIAL STATEMENTS OF THE
CANADIAN UTILITIES LIMITED REGULATED UTILITY SUBSIDIARIES

For the Years Ended December 31, 1998, 1997 and 1996

and for the Three Months ended March 31, 1999 and 1998

PRICEWATERHOUSECOOPERS

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Chartered Accountants
425 1st Street SW
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Calgary Alberta
Canada T2P 3V7
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Auditors' Report

To the Directors of CU Inc.

We have audited the combined balance sheets of the regulated utility subsidiaries of Canadian Utilities Limited as at December 31, 1998, 1997 and 1996 and the combined statements of earnings and retained earnings and cash flows for each of the years in the three year period ended December 31, 1998. These financial statements are the responsibility of the management of CU Inc. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 combined financial statements present fairly, in all material respects, the financial position of the regulated utility subsidiaries of Canadian Utilities Limited as at December 31, 1998, 1997 and 1996 and the results of their operations and cash flows for each of the years in the three year period ended December 31, 1998 in accordance with generally accepted accounting principles.

"PricewaterhouseCoopers LLP"

Chartered Accountants
Calgary, Alberta
April 20, 1999

COMBINED FINANCIAL STATEMENTS OF THE
CANADIAN UTILITIES LIMITED REGULATED UTILITY SUBSIDIARIES
STATEMENT OF EARNINGS AND RETAINED EARNINGS

(Millions of Canadian Dollars)

	Note	Twelve Months Ended December 31			Three Months Ended March 31	
		1998	1997	1996	1999	1998
					(Unaudited)	
Revenues		**$1,556.8**	$1,579.9	$1,491.8	$524.2	$463.9
Costs and expenses						
Natural gas supply		**376.3**	400.9	311.1	169.8	117.2
Fuel and purchased power		**126.1**	124.0	120.8	42.6	36.1
Operation and maintenance		**306.9**	325.8	327.5	77.8	70.0
Depreciation and depletion		**179.3**	174.4	168.0	52.8	51.5
Franchise, property and other taxes		**100.3**	103.5	98.2	30.8	31.6
		1,088.9	1,128.6	1,025.6	373.8	306.4
Financing charges and other						
Interest expense		**5.6**	1.8	5.7	1.3	1.2
Interest expense to parent corporation		**135.6**	135.7	140.4	34.2	34.1
Dividends on retractable preferred shares to parent corporation		**18.0**	18.6	27.8	2.8	4.7
Interest and other income		**(9.8)**	(11.2)	(10.7)	(1.3)	(1.7)
		149.4	144.9	163.2	37.0	38.3
Earnings before income taxes		**318.5**	306.4	303.0	113.4	119.2
Income taxes	2	**156.8**	146.4	152.6	54.0	58.3
Net earnings		**161.7**	160.0	150.4	59.4	60.9
Dividends on non-retractable equity preferred shares		**-**	-	0.8	-	-
Dividends on non-retractable equity preferred shares to parent corporation		**6.4**	8.4	4.7	2.4	1.5
Earnings attributable to Class A and Class B shares		**155.3**	151.6	144.9	57.0	59.4
Retained earnings at beginning of period		**781.7**	729.4	652.4	854.7	781.7
		937.0	881.0	797.3	911.7	841.1
Dividends on Class A and Class B shares		**82.3**	99.3	67.9	23.7	20.6
Retained earnings at end of period		**$ 854.7**	$ 781.7	$ 729.4	$ 888.0	$ 820.5

COMBINED FINANCIAL STATEMENTS OF THE
CANADIAN UTILITIES LIMITED REGULATED UTILITY SUBSIDIARIES
BALANCE SHEET

(Millions of Canadian Dollars)

		December 31			March 31	
	Note	1998	1997	1996	1999	1998
					(Unaudited)	
ASSETS						
Current assets						
Cash and short term investments		**$ -**	$ -	$ -	$ 62.8	$ 27.1
Short term advances to parent corporation		**-**	-	13.4	-	-
Accounts receivable		**275.5**	234.1	232.3	221.5	227.1
Owing from parent and affiliated corporations		**3.1**	2.8	3.0	1.5	2.0
Inventories		**93.3**	81.9	63.2	62.0	56.0
Deferred natural gas costs		**6.0**	(1.6)	34.9	(6.2)	14.0
Prepaid expenses		**8.5**	5.2	3.2	7.5	4.8
		386.4	322.4	350.0	349.1	331.0
Property, plant and equipment	3	**3,095.2**	3,037.3	2,976.2	3,070.3	3,037.6
Deferred financing charges		**8.9**	11.4	13.6	8.8	10.8
Other assets		**47.0**	19.7	13.9	53.2	20.2
		$3,537.5	$3,390.8	$3,353.7	$3,481.4	$3,399.6
LIABILITIES AND SHAREHOLDER'S EQUITY						
Current liabilities						
Bank indebtedness		**$ 37.5**	$ 38.0	$ 26.8	$ 1.2	$ 2.2
Short term advances from parent and affiliated corporations		**-**	4.0	30.8	-	-
Accounts payable and accrued liabilities		**151.3**	151.2	156.7	124.9	140.8
Owing to parent and affiliated corporations		**54.2**	39.7	53.6	61.8	53.4
Income and other taxes payable		**37.1**	49.0	62.5	42.8	55.1
		280.1	281.9	330.4	230.7	251.5
Future income taxes	2	**57.4**	41.6	4.5	58.2	41.9
Unearned revenues		**5.0**	5.0	9.1	6.0	4.9
Other deferred credits		**4.1**	4.0	12.4	4.3	4.0
Notes payable	5	**20.0**	-	-	-	-
Notes payable to parent corporation	5	**164.7**	5.3	5.2	184.7	5.3
Long term debt	4	**4.5**	6.2	6.5	4.5	6.3
Long term debt to parent corporation	4	**1,357.8**	1,407.8	1,399.4	1,315.8	1,407.9
Retractable preferred shares to parent corporation	6	**200.0**	325.0	325.0	200.0	325.0
Non-retractable equity preferred shares to parent corporation	6	**186.9**	130.0	129.5	186.9	130.0
Class A and Class B shareholder's equity						
Class A and Class B shares	7	**402.3**	402.3	402.3	402.3	402.3
Retained earnings		**854.7**	781.7	729.4	888.0	820.5
		1,257.0	1,184.0	1,131.7	1,290.3	1,222.8
		$3,537.5	$3,390.8	$3,353.7	$3,481.4	$3,399.6

"C.O. Twa"
C.O. Twa, Director

"B.K. French"
B.K. French, Director

COMBINED FINANCIAL STATEMENTS OF THE
CANADIAN UTILITIES LIMITED REGULATED UTILITY SUBSIDIARIES
STATEMENT OF CASH FLOWS

(Millions of Canadian Dollars)

	Twelve Months Ended December 31			Three Months Ended March 31	
	1998	1997	1996	1999	1998
Operating activities				(Unaudited)	
Earnings attributable to Class A and Class B shares	**$ 155.3**	$ 151.6	$ 144.9	$ 57.0	$ 59.4
Non-cash items included in earnings					
Depreciation and depletion	**179.3**	174.4	168.0	52.8	51.5
Future income taxes	**15.9**	16.7	4.1	(6.2)	0.2
Other - net	**2.6**	(7.3)	9.8	0.6	1.6
Cash flow from operations	**353.1**	335.4	326.8	104.2	112.7
Changes in non-cash working capital	**(59.1)**	(13.2)	29.4	95.2	23.5
	294.0	322.2	356.2	199.4	136.2
Investing activities					
Capital expenditures - net	**(273.3)**	(274.8)	(213.6)	(34.3)	(57.9)
Contributions by customers for extensions to utility plant	**37.8**	36.8	30.4	7.8	7.1
Other	**(8.0)**	(4.2)	6.3	(5.6)	4.6
	(243.5)	(242.2)	(176.9)	(32.1)	(46.2)
Financing activities					
Change in notes payable	**20.0**	-	-	(20.0)	-
Change in notes payable to parent corporation	**159.4**	0.1	(0.1)	20.0	-
Issue of long term debt to parent corporation	**-**	68.0	1.5	-	-
Repayment of long term debt	**(1.7)**	(0.3)	(0.5)	-	-
Repayment of long term debt to parent corporation	**(50.0)**	(59.6)	(24.2)	(42.0)	-
Issue of non-retractable equity preferred shares to parent corporation	**-**	110.0	20.0	-	-
Redemption of retractable preferred shares to parent corporation	**(68.1)**	-	(76.9)	-	-
Redemption of non-retractable equity preferred shares	**-**	-	(20.0)	-	-
Redemption of non-retractable equity preferred shares to parent corporation	**-**	(109.5)	-	-	-
Dividends paid to Class A and Class B shareholders	**(82.3)**	(99.3)	(67.9)	(23.7)	(20.6)
Other	**(23.3)**	12.8	(2.0)	(2.5)	(2.5)
	(46.0)	(77.8)	(170.1)	(68.2)	(23.1)
Cash position[1]					
Increase (decrease)	**4.5**	2.2	9.2	99.1	66.9
Beginning of period	**(42.0)**	(44.2)	(53.4)	(37.5)	(42.0)
End of period	**$ (37.5)**	$ (42.0)	$ (44.2)	$ 61.6	$ 24.9

[1] Cash position is defined as cash and short term investments and short term advances to parent corporation less current bank indebtedness and short term advances from parent and affiliated corporations.

NOTES TO COMBINED FINANCIAL STATEMENTS

December 31, 1998
(tabular amounts in millions of Canadian dollars)

1. Summary of significant accounting policies

Financial Statement Presentation

The combined financial statements of the Canadian Utilities Limited regulated utility subsidiaries include the accounts of Northwestern Utilities Limited, Canadian Western Natural Gas Company Limited and CU Water Limited (regulated natural gas operations) and Alberta Power Limited (regulated electric operations). The combined financial statements have been prepared by management from the consolidated financial statements of Canadian Utilities Limited using the historical book values of its respective subsidiaries.

Regulation

The subsidiaries 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 award interim rates, subject to final determination.

Revenue Recognition

Revenues are recognized on the accrual basis and include an estimate of services provided but not yet billed.

The Electric Utilities Act ("EUA") provides for the sale of all power for use in Alberta to a power pool for resale to distribution companies at a bid price that matches demand with supply. Existing generating units can recover a return on investment and costs of production from the distribution companies. Over-recoveries can arise where pool prices exceed variable production costs and are repayable to the distribution companies. These cost recovery mechanisms apply to existing regulated generating units. New units that are brought into production receive only pool prices.

Under provisions of the EUA, The Transmission Administrator pays the regulated costs of the electric subsidiary's transmission facilities. The Transmission Administrator administers transmission services needed to serve customers throughout Alberta and charges a uniform tariff to all distribution companies.

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 through revised rates and natural gas supply expense is adjusted accordingly.

Income Taxes

Each subsidiary follows the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not 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.

1. Summary of significant accounting policies (continued)

Property, Plant and Equipment

The subsidiaries include in capital expenditures an allowance for funds used during construction at rates approved by the AEUB for debt and equity capital.

Certain 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. Property, plant and equipment is disclosed net of unamortized contributions.

Depreciation is provided on assets on a straight-line basis over their estimated useful lives. Depreciation rates are approved by the AEUB. For certain assets these approved depreciation rates include a provision for future removal costs and site restoration costs. On retirement of depreciable assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Deferred Financing Charges

Expenses of the issue of long term debt are amortized over the weighted average life of the debt and expenses of the issue of preferred shares are amortized over the expected life of the issue. Unamortized premiums and issue costs of redeemed long term debt and preferred shares are amortized over the life of the issue funding the redemption.

Notes Payable

The subsidiaries may borrow directly from the bank under bank loan agreements that are renewed on a continuing basis and may borrow from the parent corporation, Canadian Utilities Limited. These borrowings allow the subsidiaries to manage the amount and timing of long term debt, preferred share and equity issues and are classified as long term when they intend to refinance these borrowings on a long term basis.

Long Term Debt Due Within One Year

Long term debt due within one year is classified as long term when the subsidiaries have arranged with the parent corporation to refinance that debt on a long term basis.

Hedging

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

Gains and losses are recognized in income in the same period and in the same financial statement category as the income or expense from the hedged position.

1. Summary of significant accounting policies (continued)

Retirement Benefits

The subsidiaries, together with their parent and affiliated companies, have defined benefit pension plans covering approximately 75% of employees. These plans are administered on a combined basis and no separate accounting for assets and obligations is made by each individual corporation in the group. Employees participate through contributions to the plans, which provide for pensions based on length of service and final average earnings. The subsidiaries are assessed a percentage of their payroll at a rate calculated for the plans as a whole. The cost of pension benefits is determined using the projected benefits method prorated on service and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Plan assets are valued based on a three year average of market values. Adjustments resulting from plan enhancements, experience gains and losses and changes in assumptions are amortized over the estimated average remaining service life of employees.

The subsidiaries also have a defined contribution pension plan for employees. Employer contributions are expensed as incurred.

The cost of other benefits, principally health, dental and life insurance for retirees and their dependents, is expensed as paid.

2. Income taxes

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

	1998		1997		1996	
Earnings before income taxes	**$318.5**	**%**	$306.4	%	$303.0	%
Income taxes, at statutory rates	**$142.0**	**44.6**	$136.8	44.6	$135.1	44.6
Dividends on retractable preferred shares	**8.0**	**2.5**	8.3	2.7	12.4	4.1
Allowance for funds used	**(1.4)**	**(0.5)**	(1.5)	(0.5)	(1.5)	(0.5)
Depreciation of capitalized allowance for funds used	**3.7**	**1.2**	3.6	1.2	3.6	1.2
Crown royalties and other non-deductible Crown payments	**3.1**	**1.0**	3.0	1.0	3.2	1.1
Earned depletion and resource allowance	**(4.0)**	**(1.3)**	(4.0)	(1.3)	(3.7)	(1.2)
Unrecorded future income taxes	**1.2**	**0.4**	(3.2)	(1.0)	(1.7)	(0.6)
Large Corporations Tax	**4.7**	**1.5**	3.9	1.3	4.3	1.4
Other	**(0.5)**	**(0.2)**	(0.5)	(0.2)	0.9	0.3
	156.8	**49.2**	146.4	47.8	152.6	50.4
Current income taxes	**136.9**		145.6		133.6	
Future income taxes	**$ 19.9**		$ 0.8		$ 19.0	

	1998	1997	1996
The future income tax liabilities comprise the following:			
Property, plant and equipment	**$ 36.0**	$ 33.1	$ 4.2
Reserves	**10.4**	0.6	(0.1)
Allowance for funds used	**8.2**	5.6	-
Deferred natural gas costs	**4.3**	0.3	14.9
Deferred pension costs	**1.6**	2.0	0.5
Other	**1.2**	0.3	1.3
	61.7	41.9	20.8
Less: Amounts included in income and other taxes payable	**4.3**	0.3	16.3
	$ 57.4	$ 41.6	$ 4.5

Unrecorded future income taxes of the subsidiaries decreased by $1.2 million to $178.6 million at December 31, 1998.

3. Property, plant and equipment

		1998		1997		1996	
	Composite Depreciation Rates	**Cost**	**Accumulated Depreciation**	Cost	Accumulated Depreciation	Cost	Accumulated Depreciation
Regulated natural gas operations	3.9%	**$2,208.0**	**$ 748.3**	$2,094.1	$ 696.6	$1,955.4	$ 627.3
Regulated electric operations	3.6%	**3,163.1**	**1,137.4**	3,061.2	1,053.9	2,962.5	971.1
		$5,371.1	**1,885.7**	$5,155.3	1,750.5	$4,917.9	1,598.4
Property, plant and equipment, less accumulated depreciation			**3,485.4**		3,404.8		3,319.5
Unamortized contributions by customers for extensions to utility plant			**390.2**		367.5		343.3
			$3,095.2		$3,037.3		$2,976.2

Accumulated depreciation includes an amount provided for future removal and site restoration costs, net of salvage value, of $156.9 million (1997 - $137.1 million, 1996 - $114.4 million).

Composite depreciation rates reflect total depreciation expensed and capitalized as a percentage of mid-year cost, excluding non-depreciable assets and construction work-in-progress.

4. Long term debt

	1998	1997	1996
Long term debt			
1988 Series 12% due September 1998 (sinking fund)	**$ -**	$ 1.5	$ 1.6
1990 Series 11.125% due December 1999	**0.7**	0.7	0.7
1992 Term Loan 8.37% due December 2002 (sinking fund)	**3.8**	4.0	4.2
	$ 4.5	$ 6.2	$ 6.5
Long term debt to parent corporation			
Debentures			
1982 Series 17.5% due March 1997 (sinking fund)	**$ -**	$ -	$ 21.0
1994 Medium Term Note 8.95% due July 1997	**-**	-	35.0
1988 Series 11.25% due September 1998	**-**	50.0	50.0
1995 Medium Term Note 7.55% due January 1999	**42.0**	42.0	42.0
1994 Medium Term Note 8.81% due April 2000	**50.0**	50.0	50.0
1997 Medium Term Note 5.42% due November 2002	**68.0**	68.0	-
1993 Series 7.25% due September 2003	**60.0**	60.0	60.0
1994 Series 8.73% due June 2004	**100.0**	100.0	100.0
1995 Series 8.43% due June 2005	**125.0**	125.0	125.0
1986 Series 9.85% due October 2006, redeemable October 2001	**100.0**	100.0	100.0
1986 Second Series 10.25% due December 2006, redeemable December 2001	**90.0**	90.0	90.0
1987 Series 12% due October 2007, redeemable October 2002	**125.0**	125.0	125.0
1989 Series 10.20% due November 2009	**125.0**	125.0	125.0
1990 Series 11.40% due August 2010	**125.0**	125.0	125.0
1990 Second Series 11.77% due November 2020	**100.0**	100.0	100.0
1991 Series 9.92% due April 2022	**125.0**	125.0	125.0
1992 Series 9.40% due May 2023	**100.0**	100.0	100.0
	1,335.0	1,385.0	1,373.0
Other long term obligations, at rates from 6.5% to 7.36%	**14.5**	14.5	18.1
Non-interest bearing long term advances	**8.3**	8.3	8.3
	$1,357.8	$1,407.8	$1,399.4

4. Long term debt (continued)

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

1999	2000	2001	2002	2003
$42.9	$63.7	$0.2	$71.2	$61.0

The $42.9 million due in 1999 is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Redemption privileges

Certain debentures of the subsidiaries are redeemable prior to maturity on the dates specified above at the principal value plus accrued and unpaid interest.

Fair values

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

	1998	1997	1996
Long term debt			
Fixed rate	**$ 0.7**	$ 2.4	$ 2.6
Floating rate	**3.8**	4.0	4.2
	$ 4.5	$ 6.4	$ 6.8
Long term debt to parent corporation			
Fixed rate	**$1,735.1**	$1,760.9	$1,689.9

5. Notes payable and credit lines

At December 31, 1998, notes payable includes bank borrowings of $20.0 million (1997 - nil, 1996 - nil) at an interest rate of 5.24%, maturing January 1999, and notes payable to parent corporation of $164.7 million (1997 - $5.3 million, 1996 - $5.2 million), at interest rates ranging from 5.175% to 5.225%, maturing March 1999.

The subsidiaries have credit lines totaling $176.6 million, which are available on an uncommitted basis by the lenders. In addition, their parent corporation, Canadian Utilities Limited, has credit lines totaling $210.0 million for utility purposes, of which $150.0 million are available on a committed basis by the lenders and $60.0 million are available on an uncommitted basis. These credit lines enable the subsidiaries to obtain financing for general business purposes. At December 31, 1998, $150.0 million of committed credit lines and $194.6 million of uncommitted credit lines were still available.

6. Preferred shares to parent corporation

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

Issued:

	Stated Value	Retraction and Redemption Dates	1998		1997		1996	
			Shares	**Amount**	Shares	Amount	Shares	Amount
	(dollars)							
Retractable								
Cumulative Redeemable								
Second Preferred Shares								
5.9% Series Q	$25.00	-	**-**	**$ -**	5,000,000	$125.0	5,000,000	$125.0
5.3% Series R	$25.00	June 1, 1999	**6,000,000**	**150.0**	6,000,000	150.0	6,000,000	150.0
6.6% Series S	$25.00	March 1, 2000	**2,000,000**	**50.0**	2,000,000	50.0	2,000,000	50.0
				$200.0		$325.0		$325.0
Non-retractable								
Cumulative Redeemable								
Preferred Shares								
5 5/8%	$100.00	-	**-**	**$ -**	-	$ -	105,000	$ 10.5
Cumulative Redeemable								
Second Preferred Shares								
7.3% Series C	$25.00	-	**-**	**-**	-	-	732,480	18.3
7.7% Series L	$25.00	-	**-**	**-**	-	-	604,570	15.1
7.1% Series N	$25.00	-	**-**	**-**	-	-	699,533	17.5
8.0% Series P	$25.00	-	**-**	**-**	-	-	1,923,733	48.1
5.9% Series Q	$25.00	open	**2,277,675**	**56.9**	-	-	-	-
Perpetual Cumulative								
Second Preferred Shares								
4.63% Series U	$25.00	November 26, 2001	**800,000**	**20.0**	800,000	20.0	800,000	20.0
4.66% Series V	$25.00	October 3, 2002	**4,400,000**	**110.0**	4,400,000	110.0	-	-
				$186.9		$130.0		$129.5

On December 1, 1998, 2,722,325 of Cumulative Redeemable Second Preferred Shares Series Q were retracted at a price of $25.00 per share plus accrued dividends.

The dividends payable on the Perpetual Cumulative Second Preferred Shares Series U and V are fixed until November 26, 2001 and October 3, 2002, respectively, at which time a new dividend rate may be established by negotiation between the subsidiaries and the parent corporation, Canadian Utilities Limited.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are:

	1998	1997	1996
Retractable	**$202.2**	$330.7	$340.3
Non-retractable	**$189.2**	$130.7	$133.5

Redemption and retraction privileges

The retractable Cumulative Redeemable Second Preferred Shares are retractable on the dates specified above at the option of the parent corporation, Canadian Utilities Limited, at the stated value plus accrued and unpaid dividends. The retractable and non-retractable preferred shares are redeemable on the dates specified above at the stated value plus accrued and unpaid dividends.

7. Class A and Class B shares

	1998		1997		1996	
	Shares	**Consideration**	Shares	Consideration	Shares	Consideration
Authorized: An unlimited number of Class A non-voting shares						
An unlimited number of Class B common shares						
Issued:						
Class A non-voting shares						
Beginning of year	**32,295,378**	**$250.6**	-	$ -	-	$ -
Converted: Class B to Class A	**-**	**-**	32,295,378	250.6	-	-
End of year	**32,295,378**	**250.6**	32,295,378	250.6	-	-
Class B common shares						
Beginning of year	**19,554,169**	**151.7**	51,849,547	402.3	51,849,547	402.3
Converted: Class B to Class A	**-**	**-**	(32,295,378)	(250.6)	-	-
End of year	**19,554,169**	**151.7**	19,554,169	151.7	51,849,547	402.3
	51,849,547	**$402.3**	51,849,547	$402.3	51,849,547	$402.3

8. Related party transactions

Entity	Relationship	Transaction	Recorded As	**1998**	1997	1996
Canadian Utilities Limited	Parent	Sale of electricity and natural gas and lease of land	Revenues	**$ 0.5**	$ 0.4	$ 0.1
		Administration, rent, aircraft usage, bank activity charges, computer operations and systems development, financial management and security services	Operation and maintenance	**38.3**	40.5	43.8
		Purchase of equipment, leasehold improvements and capitalized software	Property, plant and equipment	**13.4**	10.7	12.7
CU Power Canada Ltd.	Affiliate	Sale of electricity	Revenues	**3.7**	2.2	2.1
		Contract labor	Operation and maintenance	**(1.5)**	(0.5)	(0.4)
ATCO Gas Services Ltd.	Affiliate	Natural gas storage, transportation and other	Revenues	**6.6**	3.5	2.9
		Purchase, transportation and storage of natural gas	Natural gas supply	**53.9**	2.6	-
		Gas management services and other administration fees	Operation and maintenance	**2.3**	6.5	7.3
Frontec Corporation	Affiliate	Property management, security services and contract labor	Operation and maintenance	**2.2**	0.9	(0.6)
		North Warning System joint venture earnings	Other income	**0.2**	0.2	0.3

Transactions in parentheses represent cost recoveries.

These transactions are in the normal course of business and are recorded at the exchange value.

9. Commitments and contingencies

Minimum operating lease payments, which extend over periods not exceeding 13 years, are as follows:

1999	2000	2001	2002	2003	Total of All Subsequent Years
$4.6	$4.6	$4.5	$4.2	$3.2	$21.6

The subsidiaries are 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 combined financial statements.

On August 17, 1998, Canadian Western Natural Gas Company Limited filed an application with the AEUB for 1997 return on common equity and capital structure, and a general rate application for 1998. The hearing is being conducted during the first quarter of 1999, and a decision is expected by the end of 1999. The decision is not expected to have a material effect on the combined financial statements.

10. Segmented information

The subsidiaries operate in two primary business segments:

Regulated natural gas operations provide natural gas production, transmission and distribution to industrial, residential and commercial customers and water to residential and commercial customers in Alberta;

Regulated electric operations provide electric power generation, transmission and distribution to industrial, commercial and residential customers in north central Alberta and parts of the Yukon and the Northwest Territories.

10. Segmented information (continued)

1998 1997 1996	Regulated Natural Gas Operations	Regulated Electric Operations	Intersegment Eliminations	Combined
Revenues – external	**$ 880.9**	**$ 675.9**	**$ -**	**$1,556.8**
	$ 915.0	$ 664.9	$ -	$1,579.9
	$ 834.7	$ 657.1	$ -	$1,491.8
Revenues – intersegment[(1)]	**1.2**	**0.2**	**(1.4)**	**-**
	1.2	0.2	(1.4)	-
	0.7	0.2	(0.9)	-
Revenues	**882.1**	**676.1**	**(1.4)**	**1,556.8**
	916.2	665.1	(1.4)	1,579.9
	835.4	657.3	(0.9)	1,491.8
Operating expenses	**613.1**	**297.9**	**(1.4)**	**909.6**
	659.9	295.7	(1.4)	954.2
	564.9	293.6	(0.9)	857.6
Depreciation and depletion	**74.2**	**105.1**	**-**	**179.3**
	73.5	100.9	-	174.4
	67.7	100.3	-	168.0
Interest expense on debt	**53.3**	**87.9**	**-**	**141.2**
	48.2	89.4	(0.1)	137.5
	53.1	93.1	(0.1)	146.1
Dividends on retractable preferred shares	**6.3**	**11.7**	**-**	**18.0**
	6.5	12.1	-	18.6
	10.2	17.6	-	27.8
Interest and other income	**(4.2)**	**(5.4)**	**(0.2)**	**(9.8)**
	(4.4)	(6.7)	(0.1)	(11.2)
	(3.7)	(6.9)	(0.1)	(10.7)
Earnings before income taxes	**139.4**	**178.9**	**0.2**	**318.5**
	132.5	173.7	0.2	306.4
	143.2	159.6	0.2	303.0
Income taxes	**68.0**	**88.7**	**0.1**	**156.8**
	61.8	84.5	0.1	146.4
	68.2	84.3	0.1	152.6
Net earnings	**71.4**	**90.2**	**0.1**	**161.7**
	70.7	89.2	0.1	160.0
	75.0	75.3	0.1	150.4
Dividends on non-retractable equity preferred shares	**2.7**	**3.7**	**-**	**6.4**
	3.4	5.0	-	8.4
	2.2	3.3	-	5.5
Earnings attributable to Class A and Class B shares	**$ 68.7**	**$ 86.5**	**$ 0.1**	**$ 155.3**
	$ 67.3	$ 84.2	$ 0.1	$ 151.6
	$ 72.8	$ 72.0	$ 0.1	$ 144.9

10. Segmented information (continued)

1998 1997 1996	Regulated Natural Gas Operations	Regulated Electric Operations	Intersegment Eliminations	Combined
Total assets	**$1,478.8**	**$2,059.7**	**$(1.0)**	**$3,537.5**
	$1,365.6	$2,026.8	$(1.6)	$3,390.8
	$1,337.8	$2,016.8	$(0.9)	$3,353.7
Capital expenditures	**$ 143.5**	**$ 124.4**	**$ -**	**$ 267.9**
	$ 144.6	$ 122.4	$ -	$ 267.0
	$ 82.5	$ 125.8	$ -	$ 208.3

March 31, 1999 March 31, 1998				
Revenues – external	**$ 339.8**	**$ 184.4**	**$ -**	**$ 524.2**
	$ 285.2	$ 178.7	$ -	$ 463.9
Revenues – intersegment[1]	**0.3**	**-**	**(0.3)**	**-**
	0.3	-	(0.3)	-
Revenues	**340.1**	**184.4**	**(0.3)**	**524.2**
	285.5	178.7	(0.3)	463.9
Earnings attributable to Class A and Class B shares	**$ 33.3**	**$ 23.7**	**$ -**	**$ 57.0**
	$ 34.6	$ 24.8	$ -	$ 59.4
Total assets	**$1,450.4**	**$2,051.9**	**$(20.9)**	**$3,481.4**
	$1,366.6	$2,033.7	$ (0.7)	$3,399.6

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

11. Uncertainty due to the Year 2000 Issue

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000, and, if not addressed, the impact on operations and financial reporting may affect an entity's ability to conduct normal business operations. While the subsidiaries have implemented a Year 2000 program, it is not possible to be certain that all aspects of the Year 2000 Issue affecting them, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.