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CANADIAN UTILITIES LIMITED
An ATCO Company

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED
DECEMBER 31, 2007

Canadian Utilities Limited

Management's Discussion and Analysis (MD&A)
For the year ended December 31, 2007

This MD&A should be read in conjunction with the Company's unaudited consolidated financial statements for the three months ended December 31, 2007 and the audited consolidated financial statements for the year ended December 31, 2007. This MD&A is dated February 19, 2008. Additional information relating to the Company, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com.

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Glossary

Adjusted Earnings means earnings attributable to Class A and Class B shares after adjustment for items that are not in the normal course of business nor a result of day-to-day operations. These items are usually of a non-recurring or one-time nature. Refer to Reconciliation of Earnings Attributable to Class A and Class B shares and Adjusted Earnings section for a description of these items (non GAAP items).

Adjusted Earnings per Share is calculated by dividing Adjusted Earnings for a period by the weighted average number of Class A and Class B shares outstanding during the period (non GAAP items).

AESO means the Alberta Electric System Operator.

Alberta Power Pool means the market for electricity in Alberta operated by AESO.

AUC means the Alberta Utilities Commission and its predecessor, the Alberta Energy and Utilities Board.

Availability means a measure of time, expressed as a percentage of continuous operation, that a generating unit is capable of producing electricity, regardless of whether the unit is actually generating electricity.

Class A shares means Class A non-voting shares of the Company.

Class B shares means Class B common shares of the Company.

Class I Shares means Class I Non-Voting Shares of ATCO Ltd.

Class II Shares means Class II Voting Shares of ATCO Ltd.

Company means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries.

Frac spread means the premium or discount between the purchase price of natural gas and the selling price of extracted natural gas liquids on a heat content equivalent basis.

GAAP means Canadian generally accepted accounting principles.

GHG means any greenhouse gas which has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide and hydrofluorocarbons.

Gigajoule (GJ) means a unit of energy equal to approximately 948.2 thousand British thermal units.

Mark-to-market means assigning a value to a contract or financial instrument based on the current market prices for that instrument or similar instruments.

Megawatt (MW) means a measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) means a measure of electricity consumption equal to the use of 1,000,000 watts of power over a one-hour period.

NGL means natural gas liquids, such as ethane, propane, butane and pentanes plus, that are extracted from natural gas and sold as distinct products or as a mix.

Petajoule (PJ) means a unit of energy equal to approximately 948.2 billion British thermal units.

PPA means Power Purchase Arrangements that became effective on January 1, 2001, as part of the process of restructuring the electric utility business in Alberta. The PPAs are legislatively mandated and approved by the AUC.

Propane Plus means propane, butane, pentane and other hydrocarbons other than methane and ethane.

Shrinkage Gas means the natural gas which is used to replace, on a heat equivalent basis, the NGL extracted during NGL extraction operations.

Spark spread means the difference between the selling price of electricity and the marginal cost of producing electricity from natural gas. In this MD&A, spark spreads are based on an approximate industry heat rate of 7.5 GJ per MWh.

U.K. means United Kingdom.

Company Overview

Canadian Utilities Limited, an Alberta based worldwide organization of companies with assets of approximately $7.3 billion, and more than 6,500 employees, is comprised of three main business divisions: Utilities (natural gas and electric transmission and distribution); Power Generation; and Global Enterprises (technology, logistics and energy services).

The consolidated financial statements include the accounts of Canadian Utilities Limited and all of its subsidiaries. The consolidated financial statements have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

The Company operates in the following business segments:

The **Utilities** Business Group includes:

- the regulated distribution of natural gas by ATCO Gas;
- the regulated transmission and distribution of water by CU Water;
- the regulated transmission of natural gas by ATCO Pipelines;
- the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical; and
- the provision of non-regulated complementary projects by ATCO Energy Solutions (formerly ATCO Utility Services).

The **Power Generation** Business Group includes:

- the non-regulated supply of electricity and cogeneration steam by ATCO Power;
- the regulated supply of electricity by Alberta Power (2000); and
- the sale of fly ash and other combustion byproducts produced in coal-fired electrical generating plants by ASHCOR Technologies.

The **Global Enterprises** Business Group includes:

- the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream;
- the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec;
- the development, operation and support of information systems and technologies, and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- the sale of travel services to both business and consumer sectors by ATCO Travel.

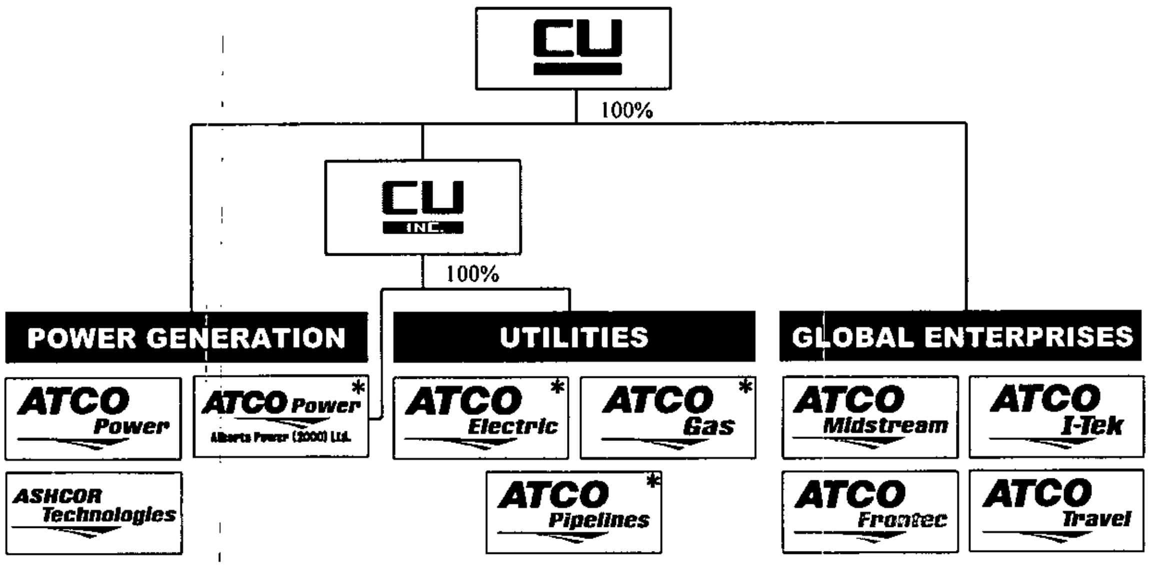
The Corporate and Other segment includes commercial real estate owned by the Company in Alberta.

Transactions between business segments are eliminated in all reporting of the Company's consolidated financial information. For additional information on the Company's business segments, refer to Note 24 of the consolidated financial statements.

Canadian Utilities focuses on operational excellence through transparency, defined accountability, clear communication of corporate goals, pre-emptive decision making, and proactive management. Since repatriation from the United States, some 28 years ago, Canadian Utilities has consistently represented solid performance, quality products and services, and customer satisfaction, while maintaining a commitment to safety, the environment and the communities it serves.

Canadian Utilities' diversity of operations offer stable utility earnings while providing the opportunity to develop profitable products and services in non-regulated businesses.

Simplified Organizational Structure



* Regulated operations include ATCO Electric, ATCO Gas, ATCO Pipelines and the Battle River and Sheerness generating plants of Alberta Power (2000) Ltd.

Forward-Looking Information

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves 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 information. The Company believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

In particular, this MD&A contains forward-looking information pertaining to contractual obligations, planned capital expenditures, the impact of changes in government regulation, non-regulated generating capacity subject to long term contracts and the impact of commodity prices. Actual results could differ materially from those anticipated in this forward-looking information as a result of regulatory decisions, competitive factors in the industries in which the Company operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Company.

Non-GAAP Measures

The Company uses the measures "funds generated by operations", "Adjusted Earnings" and "Adjusted Earnings per Class A and Class B Share" in this MD&A. These measures do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

Funds generated by operations is defined as cash flows from operations before changes in non-cash working capital. In management's opinion, funds generated by operations is a significant performance indicator of the Company's ability to generate cash during a period to fund its capital expenditures without regard to changes in non-cash working capital during the period.

Adjusted Earnings is defined as earnings attributable to Class A and Class B shares after adjustment for items that are not in the normal course of business nor a result of day-to-day operations. These items are usually of a non-recurring or one-time nature. Management believes Adjusted Earnings allow for a more effective analysis of operating performance and trends. A reconciliation of Adjusted Earnings to earnings attributable to Class A and Class B shares is presented in the Results of Operations – Reconciliation of Earnings Attributable to Class A and Class B shares and Adjusted Earnings section.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2007, the Company's management evaluated the effectiveness of the design and operation of its disclosure controls and procedures as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

Disclosure controls are procedures designed to ensure that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis, and is accumulated and communicated to the Company's management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

The Company's management, inclusive of the CEO and the CFO, does not expect that Canadian Utilities' disclosure controls and procedures will prevent or detect all error and all fraud. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues and instances of fraud or error, if any, within Canadian Utilities have been detected.

Based on this evaluation, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, Canadian Utilities' disclosure controls are effective in providing reasonable assurance that material information relating to the Company and its consolidated subsidiaries is made known to the CEO and the CFO by others within those entities.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2007, management of the Company is responsible for evaluating the design of internal control over financial reporting, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and may not prevent or detect all misstatements.

There were no changes in the Company's internal controls over financial reporting that have occurred during the three months ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Annual Results of Operations

SELECTED INFORMATION

($ millions, except per share data, outstanding shares and % return on equity) [1][2]	For the Year Ended December 31 2007	2006	Change to 2007 (2007-2006)
Revenues	2,404.9	2,430.4	(1.0)%
Earnings attributable to Class A and Class B shares	386.7	323.9	19.4%
Adjusted Earnings [3]	343.8	320.8	7.2%
Total assets	7,285.4	6,993.5	4.2%
Long term debt	2,603.2	2,411.5	7.9%
Non-recourse long term debt	478.1	626.7	(23.7)%
Equity preferred shares	625.0	636.5	(1.8)%
Class A and Class B share owners' equity	2,521.7	2,324.7	8.5%
Return on equity	16.0	14.3	11.9%
Cash flow from operations	706.9	617.9	14.4%
Funds generated by operations	725.9	657.5	10.4%
Capital expenditures	700.8	567.7	23.4%
Earnings per Class A and Class B share	3.08	2.57	19.8%
Diluted earnings per Class A and Class B share	3.07	2.56	19.9%
Adjusted Earnings per Class A and Class B share [3]	2.74	2.54	7.9%
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O [4]	1.13	1.26	(10.3)%
Series Q [5]	0.68	1.48	
Series R [5]	0.61	1.33	
Series S [5]	0.77	1.65	
Series T [4]	1.09	1.26	(13.5)%
Series U [4]	1.09	1.26	(13.5)%
Series V [6]	1.28	1.31	(2.3)%
Series W	1.45	1.45	0.0%
Series X	1.50	1.50	0.0%
Class A and Class B share	1.25	1.40	(10.7)%
Equity per Class A and Class B share	20.13	18.54	8.5%
Class A and Class B shares outstanding, year end (thousands)	125,295	125,388	0.0%
Weighted average Class A and Class B shares outstanding (thousands):			
Basic	125,409	126,219	(0.6)%
Diluted	125,934	126,687	(0.6)%

Notes:

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

(2) The above data (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B share) has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

(3) Refer to Significant Non-Operating Financial Items section for a description of adjustments to arrive at Adjusted Earnings.

(4) The dividend rate was reset to $1.09 (from 5.05% to 4.35%) for dividend periods commencing between December 2, 2006, and December 2, 2011.

(5) Series Second Preferred Shares Q, R and S were redeemed on May 18, 2007.

(6) The dividend rate was reset to $1.18 (from 5.25% to 4.70%) for dividend periods commencing between October 3, 2007, and October 3, 2012.

RECONCILIATION OF EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES AND ADJUSTED EARNINGS

Adjusted Earnings are referred to in various sections of this MD&A. The following table reconciles Adjusted Earnings, which are earnings attributable to Class A and Class B shares after adjustment for items that are not in the normal course of business nor a result of day-to-day operations. These items are usually of a non-recurring or one-time nature. Refer to Reconciliation of Earnings Attributable to Class A and Class B shares and Adjusted Earnings section for a description of these items (non GAAP items). A description of each of the adjustments is provided in the Significant Non-Operating Financial Items section.

	For the Year Ended December 31	
($ millions)	**2007**	2006
Earnings attributable to Class A and Class B shares	**386.7**	323.9
H.R. Milner Income Tax Reassessment (1)	**-**	12.4
2007 Change in the Taxation of Preferred Share Dividends (2)	**(15.6)**	-
2007 Changes in Income Taxes and Rates (3)	**(14.9)**	-
2006 Changes in Income Taxes and Rates (4)	**-**	(11.8)
Mark-to-Market Adjustment (5)	**(2.9)**	-
ATCO Gas Tax Reassessments (6)	**(9.5)**	-
Calgary Stores Block (7)	**-**	(3.7)
Adjusted Earnings	**343.8**	320.8

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

Consolidated and segmented financial results include the following Significant Non-Operating Financial Items.

(1) H.R. Milner Income Tax Reassessment

In 2006, the Canada Revenue Agency (CRA) issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Company has appealed the reassessment to the Tax Court of Canada. The impact of the reassessment was a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings ($8.0 million recorded in the second quarter of 2006 and $4.4 million recorded in the third quarter of 2006), and a $28.8 million payment associated with the tax and interest assessed. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims in taxation years subsequent to the reassessed year.

(2) 2007 Change in the Taxation of Preferred Share Dividends

In 2007, the federal government announced an amendment to tax legislation pertaining to Part VI.1 tax (the tax payable on preferred share dividends paid by corporations). Prior to this change, corporations that had Part VI.1 tax payable were entitled to an income tax deduction equal to 9/4ths of the Part VI.1 tax payable. Effective January 1, 2003, this deduction was increased to three times the amount of the Part VI.1 tax payable. The CRA has been assessing corporate tax returns based on this proposed change being in effect since January 1, 2003, resulting in a reduction of taxes paid to the Canadian government. The Company recorded a one-time reduction to current income tax expense which resulted in increased earnings of $15.6 million relating to years prior to 2007. An additional increase to earnings of $0.8 million was recorded relating to the first quarter of 2007. Funds generated by operations increased by $15.6 million, offset by a similar reduction in changes in non-cash working capital, leaving the Company's cash position unchanged.

The earnings impact of the Part VI.1 tax adjustment by Business Group was as follows:

($ millions)	Years Prior to 2007	First Quarter of 2007	Total
Utilities	4.2	0.2	4.4
Power Generation	1.3	0.1	1.4
Global Enterprises	1.4	-	1.4
Corporate & Other and Intersegment Eliminations	8.7	0.5	9.2
Total	15.6	0.8	16.4

(3) 2007 Changes in Income Taxes and Rates

In 2007, the federal government announced a reduction in corporate tax rates from 19% to 15% by 2012. As a result of these changes, the Company made an adjustment to future income taxes amounting to $10.9 million in the fourth quarter of 2007. This one-time adjustment resulted in increased earnings of $10.9 million relating to the change in the future income tax liability as at December 31, 2006. An additional increase to earnings of $1.5 million was recorded relating to the change in the future income tax liability for the first nine months of 2007.

Additionally, in 2007 the British Parliament enacted a 2% reduction in the corporate income tax rate effective April 1, 2008, which impacted ATCO Power's operations in the U.K. This resulted in a further increase in the Company's 2007 earnings of $4.0 million.

The earnings impact of the 2007 Changes in Income Taxes and Rates adjustment by Business Group was as follows:

($ millions)	December 31, 2006 Balance	First 9 Months of 2007	Total
Canadian tax changes:			
Utilities	0.3	-	0.3
Power Generation	8.2	1.3	9.5
Corporate & Other and Intersegment Eliminations	2.4	0.2	2.6
	10.9	1.5	12.4
U.K. tax changes in Power Generation	4.0	-	4.0
Total	14.9	1.5	16.4

(4) 2006 Changes in Income Taxes and Rates

In 2006, federal and provincial governments announced a reduction in corporate tax rates from 22.12% to 19% by 2011 and from 11.5% to 10% by 2007 respectively. As a result of these changes, the Company made an adjustment to income taxes amounting to $11.8 million in the second quarter of 2006, most of which related to future income taxes. The adjustment increased the Company's 2006 earnings by $11.8 million.

	Total
($ millions)	
Utilities	1.9
Power Generation	7.2
Global Enterprises	2.3
Corporate and Other	0.4
Total	11.8

(5) Natural Gas Purchase Contracts and Associated Power Generation Revenue Contract Liability (Mark-to-Market Adjustment)

ATCO Power has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that ATCO Power is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, ATCO Power is required to designate these entire contracts as derivative instruments. ATCO Power recognized a non-current derivative asset of $59.0 million on January 1, 2007; thereafter, ATCO Power will record Mark-to-Market Adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts mature in November 2014.

As all but the excess volume of natural gas is committed to ATCO Power's power generation obligations, ATCO Power could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, on January 1, 2007, ATCO Power recognized a provision for a power generation revenue contract in the amount of $44.8 million, thereafter, ATCO Power will record adjustments to the power generation revenue contract liability concurrently with the Mark-to-Market Adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The Mark-to-Market Adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability increased earnings by $2.8 million, net of income taxes, for the three months ended December 31, 2007 and increased earnings by $2.9 million, net of income taxes, for the year ended December 31, 2007. At December 31, 2007, the natural gas purchase contracts derivative asset is $72.5 million and the power generation revenue contract liability is $54.2 million.

(6) ATCO Gas Tax Reassessments

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

(7) Calgary Stores Block

In October 2001, the AUC approved the sale by ATCO Gas of certain properties in the City of Calgary, known as the Calgary Stores Block, for $6.6 million (excluding costs of disposition) and directed that $4.1 million of the proceeds be allocated to customers. ATCO Gas appealed the decision through the courts until the matter was addressed by the Supreme Court of Canada on February 9, 2006. The Supreme Court decision upheld ATCO Gas' rights to these proceeds and directed the AUC to issue a new decision to this effect. In the third quarter of 2006, ATCO Gas recorded an additional $4.1 million net proceeds from the sale, which increased ATCO Gas' earnings by $3.7 million.

CONSOLIDATED REVENUES AND EARNINGS

Consolidated **revenues** in 2007 were **substantially unchanged** with a **decrease** of $25.5 million (1.0%) over 2006.

Decreased revenues were primarily attributable to the refund of future income tax balances resulting from the ATCO Electric 2007-2008 GTA Decision (refer to Regulatory Developments – ATCO Electric section), lower natural gas fuel purchases recovered on a "no-margin" basis and the impact of a fourth quarter outage at the Barking generating plant in ATCO Power's U.K. operations, and lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream. These decreases were partially offset by colder temperatures, higher sales per customer and customer growth in ATCO Gas, the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream, and the impact of finalization of customer rates related to the ATCO Electric 2007-2008 GTA Decision (refer to Regulatory Developments – ATCO Electric section).

Earnings in 2007 were $386.7 million, an **increase** of $62.8 million (19.4%), over 2006, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2007, **Adjusted Earnings** were $343.8 million, an **increase** of $23.0 million (7.2%) over 2006. The primary reasons for the increased Adjusted Earnings in 2007 were colder temperatures, higher sales per customer and customer growth in ATCO Gas, and the timing and demand of natural gas storage capacity sold, higher storage fees and higher margins for NGL extraction in ATCO Midstream. These increases were partially offset by increased operation and maintenance and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures, and lower earnings in ATCO Power's Alberta generating plants due to lower spark spreads realized on sales of electricity and the impact of a fourth quarter outage at the Barking generating plant in ATCO Power's U.K. operations.

Interest and other income increased by $5.8 million to $64.3 million mainly due to increased income earned on cash balances due to higher short term interest rates and Mark-to-Market Adjustment in ATCO Power, partially offset by the Calgary Stores Block decision in 2006 in ATCO Gas.

CONSOLIDATED EXPENSES

($ millions)	For the Year Ended December 31		
	2007	2006	Change to 2007 (2007-2006)
Operating expenses:			
Natural gas supply	**42.1**	36.4	15.7%
Purchased power	**49.9**	46.1	8.2%
Operation and maintenance	**941.6**	950.3	(0.9)%
Selling and administrative	**216.8**	207.5	4.5%
Franchise fees	**151.2**	150.4	0.5%
	1,401.6	1,390.7	0.8%
Depreciation and amortization	**351.5**	348.5	0.9%
Interest	**217.4**	222.9	(2.5)%
Dividends on equity preferred shares	**34.3**	35.8	(4.2)%
Income taxes	**77.7**	167.1	(53.5)%

In 2007, **operating expenses** were **substantially unchanged**. Increases were primarily due to increased business activity in ATCO Gas and ATCO Electric and the recording of GHG emission fees by Alberta Power (2000) recovered from its customers in accordance with the PPAs which cover costs of recent changes in environmental laws (refer to Business Risks - Environmental Matters section). These increases were partially offset by lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations.

Depreciation and amortization expenses increased primarily due to capital additions in 2006 and 2007 in the Utilities segment, partially offset by a one-time amortization expense of certain deferred items approved by the AUC for ATCO Gas in 2006.

Interest expense decreased by $5.5 million (2.5%) over 2006 primarily due to repayment of non-recourse long term debt ($122.8 million in 2007 and $64.6 million in 2006) and the H.R. Milner Income Tax Reassessment in 2006

The impact of tax adjustments in 2006 and 2007 was a **decrease** in income taxes of $89.4 million (53.5%). The following table summarizes these impacts:

($ millions)	For the Year Ended December 31		
	2007	2006	Total
H.R. Milner Tax Reassessment	**-**	(7.2)	(7.2)
2006 Change in Income Taxes and Rates	**-**	11.8	11.8
2007 Change in Income Taxes and Rates	**(14.9)**	-	(14.9)
2007 Change in Taxation of Preferred Share Dividends	**(15.6)**	-	(15.6)
2007/2006 ATCO Gas Tax Reassessments	**(8.8)**	1.0	(7.8)
2006 ATCO Gas refund of future income taxes	**-**	4.0	4.0
2007 ATCO Electric change in tax methodology:			
• refund of future income taxes	**(34.4)**	-	(34.4)
• refund of current income taxes	**(5.2)**	-	(5.2)
• impact on 2007 income taxes	**(11.8)**	-	(11.8)
2007 Provincial, Federal and Preferred Share Dividends tax changes on 2007 earnings	**(7.0)**	-	(7.0)
Other	**(1.3)**	-	(1.3)
	(99.0)	9.6	(89.4)

SEGMENTED INFORMATION

($ millions)	Utilities	Power Generation	Global Enterprises	Corporate & Other	Intersegment Eliminations	Total
			For the Year Ended December 31			
2007						
Revenues	**1,116.5**	**773.0**	**672.6**	**13.6**	**(170.8)**	**2,404.9**
Earnings attributable to Class A and Class B shares	**139.7**	**134.7**	**110.0**	**3.1**	**(0.8)**	**386.7**
2007 Changes in the Taxation of Preferred Share Dividends (2)	**(4.2)**	**(1.3)**	**(1.4)**	**(8.7)**	**-**	**(15.6)**
2007 Changes in Income Taxes and Rates (3)	**(0.3)**	**(12.2)**	**-**	**-**	**(2.4)**	**(14.9)**
Mark-to-Market Adjustment (5)	**-**	**(2.9)**	**-**	**-**	**-**	**(2.9)**
ATCO Gas Tax Reassessments (6)	**(9.5)**	**-**	**-**	**-**	**-**	**(9.5)**
Adjusted Earnings	**125.7**	**118.3**	**108.6**	**(5.6)**	**(3.2)**	**343.8**
Capital expenditures	**588.9**	**49.2**	**62.7**	**-**	**-**	**700.8**
Operating expenses	**640.6**	**422.6**	**486.1**	**18.6**	**(166.3)**	**1,401.6**
2006						
Revenues	1,110.8	799.5	667.2	12.7	(159.8)	2,430.4
Earnings attributable to Class A and Class B shares	121.2	119.2	101.0	(11.7)	(5.8)	323.9
H.R. Milner Income Tax Reassessment (1)	-	12.4	-	-	-	12.4
2006 Changes in Income Taxes and Rates (4)	(1.9)	(7.2)	(2.3)	(0.4)	-	(11.8)
Calgary Stores Block (7)	(3.7)					(3.7)
Adjusted Earnings	115.6	124.4	98.7	(12.1)	(5.8)	320.8
Capital expenditures	505.0	48.1	14.2	0.4	-	567.7
Operating expenses	601.4	431.3	490.5	18.7	(151.2)	1,390.7

Note:
(1) Number references refer to order of items disclosed in the Significant Non-Operating Financial Items section.

Utilities

Utilities **revenues** in 2007 were **substantially unchanged** with an increase of $5.7 million (0.5%) from 2006. Items that contributed to increased revenues were colder temperatures, higher sales per customer and customer growth in ATCO Gas and the impact of finalization of customer rates offset by the refund of future income tax balances resulting from the ATCO Electric 2007-2008 GTA Decision (refer to Regulatory Developments – ATCO Electric section).

Temperatures in ATCO Gas in 2007 were 1.0% warmer than normal, compared to 5.5% warmer than normal in 2006.

Earnings for 2007 were $139.7 million, an **increase** of $18.5 million (15.3%) over 2006, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2007, **Adjusted Earnings** were $125.7 million, an **increase** of $10.1 million (8.7%) over 2006. The primary reason for higher Adjusted Earnings in 2007 was colder temperatures, higher sales per customer and customer growth in ATCO Gas. This increase was partially offset by increased operation and maintenance and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures.

Capital expenditures to maintain capacity and meet planned growth were $588.9 million in 2007. Capital expenditures rose by $83.9 million from 2006 as a result of the rapid growth of the Alberta economy, customer growth, and safety and reliability enhancements. Capital expenditures for 2008 to 2010 are expected to be approximately $3.0 billion for the Utilities segment.

Regulatory Developments

The AUC administers acts and regulations regarding rates, financing, accounting, construction, operation, and service area. The return on common equity for regulated utility operations was established by the AUC using its standardized rate of return methodology for utilities in Alberta. The rate of return was established in 2004 and is adjusted annually by 75% of the change in long term Government of Canada bond yield, similar to the adjustment mechanism used by the National Energy Board. The rate of return in 2007 was 8.51% and for 2008 has been set at 8.75%. The rate of return in 2006 was 8.93%.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process. A benchmarking report was received on January 23, 2008, and an application is anticipated to be made to the AUC by the end of February 2008 to finalize the placeholder costs. An AUC decision is expected before the end of the second quarter of 2008.

Adjustments to ATCO I-Tek's fees as a result of the benchmarking report for information technology services will be retroactive to January 1, 2008. Price changes relating to ATCO I-Tek's customer care and billing contract services for ATCO Gas and ATCO Electric will be applied following renegotiation of a new fee schedule.

ATCO Electric

2007 and 2008 General Tariff Application

In November 2006, ATCO Electric filed a general tariff application (GTA) with the AUC for 2007 and 2008 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Electric also filed an application requesting interim refundable rates for transmission and distribution operations, pending the AUC's decision on the GTA. In December 2006, ATCO Electric received a decision from the AUC approving interim refundable rate increases amounting to 50% of ATCO Electric's requested increases for transmission and distribution operations.

In September 2007, the AUC issued a decision on ATCO Electric's GTA for 2007 and 2008 (ATCO Electric GTA Decision). The decision established, among other things, the amount of revenue to be collected in 2007 and 2008 from customers for transmission and distribution services. The AUC also approved a return on common equity of 8.51% for 2007, as determined by its standardized rate of return methodology. The effect of this decision on the earnings of ATCO Electric was not material as higher revenues primarily resulting from increased capital expenditures and previously approved interim customer rates were offset by a lower approved rate of return on common equity (8.51% in 2007 versus 8.93% in 2006) and other adjustments.

The decision also directed ATCO Electric to change its income tax methodology for federal purposes. This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in the third quarter, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $49.3 million, offset by a regulatory asset of $14.9 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities increased by $34.4 million as a result of this decision. In December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers, thereby realizing $5.2 million of current income tax savings, which further reduced revenues, and reduced the future income taxes to be refunded by $10.9 million, and will be refunding the remaining $23.5 million balance to distribution customers over a five year period commencing in 2008.

Transmission Infrastructure Projects

In August 2006, the AUC approved the AESO application for increased transmission infrastructure in northwest Alberta. The AESO has approval to assign to the transmission facility owner, ATCO Electric, work consisting of several distinct projects that is expected to result in 725 kilometres of new transmission lines to be constructed by 2011.

The first of these projects was assigned by the AESO in June 2007, with final approval received from the AUC on November 23, 2007. This first project consists of the construction of a 226 kilometre transmission line with an estimated cost of $210 million and anticipated completion by March 31, 2010.

As a result of price escalation caused by the change in completion date of the remaining distinct projects (post 2010), coupled with the increasing costs of construction in Alberta, ATCO Electric is unable to estimate the cost of the entire project at this time.

In addition to the increased transmission infrastructure in northwestern Alberta, ATCO Electric anticipates that an additional 180 kilometres of transmission line projects will be required in its service area over the next five years.

ATCO Gas

2005, 2006, and 2007 General Rate Application

On January 27, 2006, ATCO Gas received a decision on its general rate application which was filed with the AUC in May 2005 for 2005, 2006, and 2007. The decision established the amount of revenue ATCO Gas can recover through distribution rates for natural gas distribution service to its customers for 2005 through 2007. The AUC also approved a rate of return on common equity of 9.5% for 2005, 8.93% for 2006 and 8.51% for 2007, as determined by its standardized rate of return methodology.

In May 2006, the City of Calgary filed a review and variance application with the AUC, alleging that the AUC made errors in the decision related to the calculation of working capital needed by ATCO Gas to operate its Carbon natural gas storage facility. The AUC issued its decision on January 17, 2007, denying the City of Calgary's application. On February 15, 2007, the City of Calgary filed for leave to appeal this review and variance decision with the Alberta Court of Appeal. On June 19, 2007, the application was heard with the court granting the City of Calgary leave to appeal on August 31, 2007. The appeal is scheduled to be presented at a hearing set for September 9, 2008.

In October 2006, ATCO Gas filed a review and variance application with the AUC for the ATCO Gas general rate application (GRA) decision. The application alleges that the AUC made errors in the ATCO Gas GRA decision related to the approved level of administrative expense. In December 2006, the AUC issued a decision which acknowledged an error for a portion of the administrative expense in question. On April 18, 2007, the AUC agreed to review its original decision. On November 27, 2007, a decision on this matter was received granting ATCO Gas $4.7 million in costs to be collected during the first two quarters of 2008, with a total increase to ATCO Gas' 2007 earnings of $3.2 million.

2008 and 2009 General Rate Application

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

Carbon Natural Gas Storage Facility

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta. ATCO Gas has leased the entire storage capacity of the facility to ATCO Midstream. ATCO Gas has taken the position that the facility is no longer required for utility service and should be removed from regulation. In the process of obtaining AUC approval a number of significant events have occurred. In July 2004, the AUC initiated a written process to consider its role in regulating the operations of the facility. In June 2005, the AUC issued a decision with respect to this process. In addition to addressing other matters, the decision found that the AUC has the authority, when necessary in the public interest, to direct a utility to utilize a particular asset in a specific manner, even over the objection of the utility. ATCO Gas filed for leave to appeal the decision with the Alberta Court of Appeal. In October 2005, the AUC established processes to review the use of the facility for utility purposes. A hearing to review the use of the facility for revenue generation was held in April 2006, and a hearing to review the use of the facility for load balancing was held in June 2006. On October 11, 2006, the AUC issued a decision confirming ATCO Gas' position that the facility is no longer required for utility service with respect to the use of the facility for load balancing purposes. The City of Calgary then filed a leave to appeal and a Review and Variance application of this decision. On February 5, 2007, the AUC issued a decision in which it determined that a legitimate utility use for the facility is that it be used for purposes of generating revenues to offset customer rates. This decision requires ATCO Gas to maintain the status quo with respect to the use of the facility including the lease of the entire facility to ATCO Midstream. On February 26, 2007, ATCO Gas filed for leave to appeal this decision with the Alberta Court of Appeal (refer to Business Risks - Regulated Operations – Carbon Natural Gas Storage Facility section). The Alberta Court of Appeal granted ATCO Gas' leave to appeal on October 24, 2007. A hearing has been set for May 9, 2008.

Deferred Gas Account

ATCO Gas has filed an application with the AUC to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in the Company's pipelines) that have impacted ATCO Gas' deferred gas account. In April 2005, the AUC issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in a decrease to ATCO Gas' 2005 revenues and earnings of $1.8 million and $1.2 million, respectively. The City of Calgary filed a leave to appeal the AUC's decision. ATCO Gas filed a cross appeal of the AUC's decision. The leave to appeal was heard by the Alberta Court of Appeal on April 18, 2006. On July 7, 2006, the Alberta Court of Appeal issued its decision granting the City of Calgary's leave to appeal on the question of whether the AUC erred in law or jurisdiction in assuming that it had the authority to allow recovery in 2005, for costs relating to prior years. At a hearing on April 13, 2007, the Alberta Court of Appeal declined to consider the City of Calgary's appeal and referred the jurisdictional question back to the AUC. On September 5, 2007, the AUC commenced proceedings to address the jurisdictional question. On January 3, 2008, the AUC issued a decision confirming its jurisdiction to approve the prior period adjustment it had approved previously.

ATCO Pipelines

2008 and 2009 General Rate Application

On October 1, 2007, ATCO Pipelines filed a general rate application for the 2008 and 2009 test years requesting increased revenues to recover increased financing, depreciation, and operating costs associated with an increased rate base in Alberta. In November 2007, ATCO Pipelines filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Pipelines received a decision from the AUC approving interim adjustable rate increases amounting to 40% of ATCO Pipelines' requested revenue increase. A decision from the AUC on the general rate application is not expected until the fourth quarter of 2008.

On October 5, 2007, the AUC approved ATCO Pipelines' request to negotiate, until January 11, 2008, a settlement with customers for revenue requirements. On January 11, 2008, ATCO Pipelines informed the AUC that a negotiated settlement had not been reached.

Competitive Proceedings

During 2007, the AUC reinstituted its review of the competitive natural gas pipeline issues under its jurisdiction. This review will address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. (NOVA). This review process is continuing.

Other Matters

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

Power Generation

Power Generation 2007 **revenues decreased** by $26.5 million (3.3%) over 2006, primarily as a result of lower natural gas fuel purchases recovered on a "no-margin" basis and the impact of a fourth quarter outage at the Barking generating plant in ATCO Power's U.K. operations. These decreases were partially offset by the recording of GHG emission fees by Alberta Power (2000) recovered from its customers in accordance with the PPAs which cover costs of recent changes in environmental laws (refer to Business Risks - Environmental Matters section).

Earnings for 2007 were $134.7 million, an **increase** of $15.5 million (13.0%) over 2006 including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings were $118.3 million, a **decrease** of $6.1 million (4.9%) over 2006. The primary reasons for the lower Adjusted Earnings in 2007 were lower earnings in ATCO Power's Alberta generating plants due to lower spark spreads realized on sales of electricity, higher general and administrative costs in ATCO Power's operations and the impact of a fourth quarter outage at the Barking generating plant in ATCO Power's U.K. operations.

Availability of Power Generation's generating plants by geographic region is set forth below:

	For the Year Ended December 31		
	2007	2006	Change to 2007 (2007-2006)
ATCO Power			
Canada	**96.3%**	95.7%	0.6%
U.K. [1]	**83.2%**	91.6%	(8.4)%
Australia	**94.6%**	94.4%	0.2%
Alberta Power (2000)			
Canada	**90.2%**	90.0%	0.2%

Note:
(1) The lower availability in 2007 reflects the outage at the Barking generating plant which started on October 25, 2007. The plant is expected to return to service in March 2008.

Unplanned Outage at Barking Power Plant

On October 25, 2007, ATCO Power's 1,000 MW Barking generating plant in the U.K. experienced an unplanned outage due to failure in a steam turbine generator. This outage reduced the plant capacity to approximately 400 MWs during this period. The financial impact of the failure was a decrease to ATCO Power's 2007 earnings of approximately $8.6 million. Discussions have been ongoing with insurers and their advisers, who have endorsed the repair strategy and have approved interim payments which commenced in early 2008. As a result of the uncertainty of the timing of the units return to service and the ability to allocate the interim payment proceeds, ATCO Power's first quarter 2008 earnings may be lower as a result of this continuing situation.

TXU Europe Settlement

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited (TXU Europe) which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Company, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

In settlement of its claim, Barking Power received distributions of £144.5 million (approximately $327 million) in 2005, of which the Company's share was $83.1 million, and distributions of £34.8 million (approximately $71 million) in 2006, of which the Company's share was $18.2 million. Income taxes of approximately $28.5 million relating to the distributions have been paid.

The Company's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2007, earnings after income taxes of approximately $10 million per year have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

On May 31, 2007, £95.0 million of the TXU proceeds, of which the Company's share was $52.7 million, were applied to Barking Power's non-recourse long term debt.

Other Power Generation Developments

On January 30, 2008, Alberta Power (2000)'s 150 MW Battle River Unit 4 experienced an unplanned outage due to a failure in the unit's generator. It is anticipated that the unit will remain off-line until mid March 2008. Alberta Power (2000) has claimed Force Majeure relief under the provisions of its PPA. If the claim for relief is successful, Alberta Power (2000) does not expect any material financial impact. If the claim for relief is not successful, the cash impact will be approximately $10 million. Due to the availability incentive pool deferral account, Alberta Power (2000) does not expect any material earnings impact in 2008 as a result of this outage.

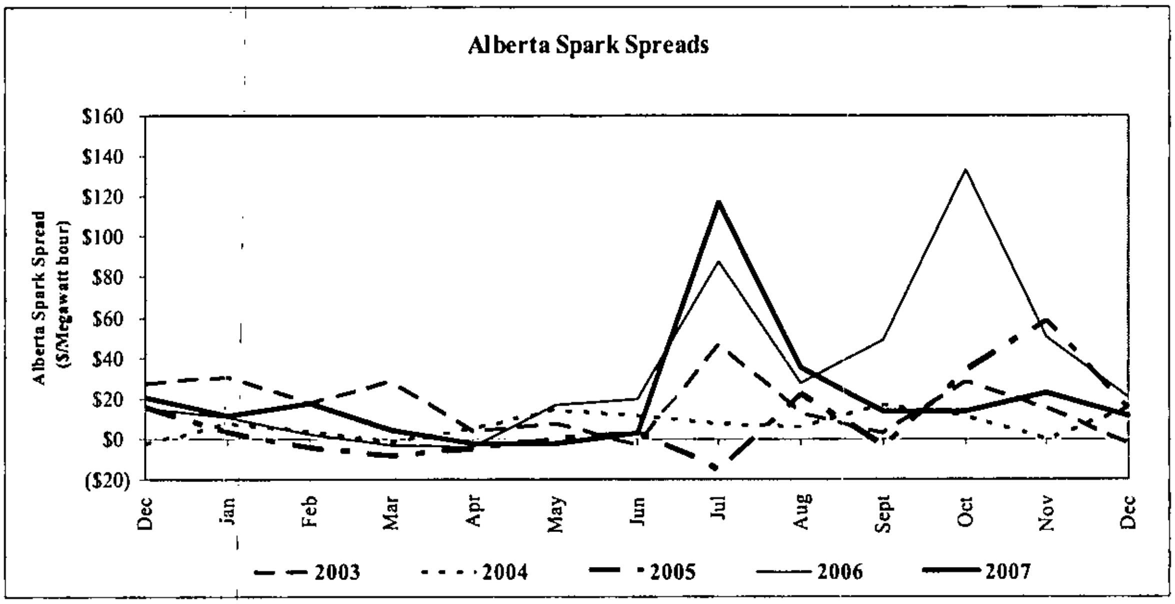
On July 1, 2007, the Piikani Nation of Brockett, Alberta exercised its option to purchase a 25% interest in ATCO Power's and ATCO Resources' 32 MW hydroelectric generating plant at the Oldman River dam near Pincher Creek, Alberta.

On May 10, 2007, ATCO Power announced that it would construct a 45 MW natural gas-fired generating unit for its Valleyview generating plant in Valleyview, Alberta. All of the electricity produced by the unit is to be sold to the Alberta Power Pool. Construction of the unit is expected to be completed in the fourth quarter of 2008.

The majority of ATCO Power's electricity sales to the Alberta Power Pool are from natural gas-fired generating plants, and as a result earnings are affected by natural gas prices and Alberta Power Pool prices. Alberta Power Pool electricity prices averaged $66.95 per MWh in 2007, compared to average prices of $80.79 per MWh in 2006. Natural gas prices averaged $6.10 per GJ, compared to average prices of $6.17 per GJ in 2006. These electricity and natural gas prices resulted in an average Spark spread of $21.22 per MWh in 2007, down from $34.52 per MWh in 2006.

Changes in spark spread affect the results of approximately 406 MW of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta-owned capacity of approximately 1,709 MWs and approximately 70 MW of plant capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of approximately 262 MW and a worldwide owned capacity by ATCO Power and Alberta Power (2000) of approximately 2,474 MW.

The following chart demonstrates the volatility of Alberta sparks spreads experienced by ATCO Power for the period of December 2002 to December 2007.



The Company's merchant power sales are effected by volatility in power and natural gas prices caused by market forces such as fluctuating supply and demand for electricity. The Company manages this volatility through its adoption of asset optimization strategies for bidding its merchant power into both the Alberta and U.K. power markets.

Alberta Power (2000)

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

Alberta Power (2000) operated the Rainbow generating plant during 2006 and the electricity generated was sold to the Alberta Power Pool. Alberta Power (2000) had one year after the expiry of the PPA for the Rainbow generating plant (December 31, 2005) to determine whether to decommission the plant in order to fully recover plant decommissioning costs or to continue to operate the plant. In 2007, the AESO and Alberta Power (2000) executed a contract resulting in Alberta Power (2000) continuing to operate the plant and thus be responsible for future decommissioning costs. These costs are included in Alberta Power (2000)'s asset retirement obligation liability. Under the terms of the agreement, the Company makes the plant available for transmission support services and can continue to sell energy into the Alberta Power Pool.

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, 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 Government of 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 PPAs were based. The return on common equity rate used in its PPA tariff calculations for Alberta Power (2000) was 8.65% in 2007 and 8.75% for 2006. The rate of return on common equity for 2008 is 8.88%.

Under the terms of the PPAs, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets, and penalties are payable by Alberta Power (2000) when the availability targets are not achieved.

Accumulated incentives in excess of accumulated penalties are deferred. For any of the individual PPAs, 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 PPAs. 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.

During 2007, the deferred availability incentive account increased by $2.2 million to $41.8 million at December 31, 2007, due to additional availability incentives received for plant availability in excess of amortization and planned outages. During 2007, the amortization of deferred availability incentives, recorded in revenues, increased by $1.2 million to $11.8 million, compared to 2006.

Greenhouse Gas Emissions

In 2007, Alberta Power (2000) began to record GHG emissions fees recovered from its customers in accordance with the PPAs which cover costs of recent changes in environmental laws (refer to Business Risks – Environmental Matters section). As the collection of the majority of these fees is on a flow-through basis, there is minimal impact on the earnings of Alberta Power (2000).

Global Enterprises

Global Enterprises **revenues increased** by $5.4 million (0.8%) from 2006. Items that increased revenues include the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream. These increases were offset by lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream.

Earnings for 2007 were $110.0 million, an **increase** of $9.0 million (8.9%) over 2006, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2007, **Adjusted Earnings** were $108.6 million, an **increase** of $9.9 million (10.0%) over 2006. The primary reason for the higher Adjusted Earnings in 2007 was the timing and demand of natural gas storage capacity sold, higher storage fees and higher margins for NGL in ATCO Midstream.

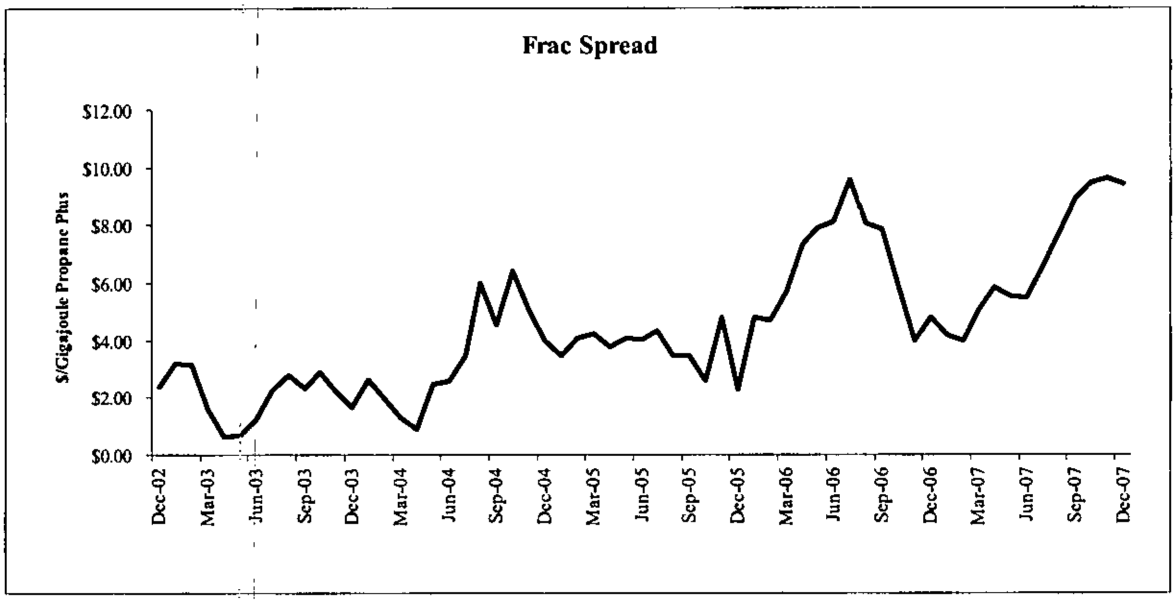
ATCO Midstream

ATCO Midstream provides non-regulated gathering and processing, NGL extraction, and natural gas storage services to natural gas producers.

NGL Extraction Operations

A portion of ATCO Midstream's revenues is derived from the extraction of NGL from natural gas and the marketing of NGL products under supply or marketing contracts. Total licensed capacity of ATCO Midstream's NGL plants is 371 million cubic feet per day.

ATCO Midstream's NGL extraction operations involve the extraction of NGL from natural gas and the replacement (on a heat content equivalent basis) of the NGL extracted with shrinkage gas. For Propane Plus, the difference between the price of natural gas and the value of the liquids extracted is commonly referred to as the frac spread. Frac spreads vary with fluctuations in the price of natural gas and the prices of the applicable liquid extracted. Frac spreads can be volatile, as shown in the following graph, which illustrates monthly frac spreads during the period of December 2002 to December 2007.



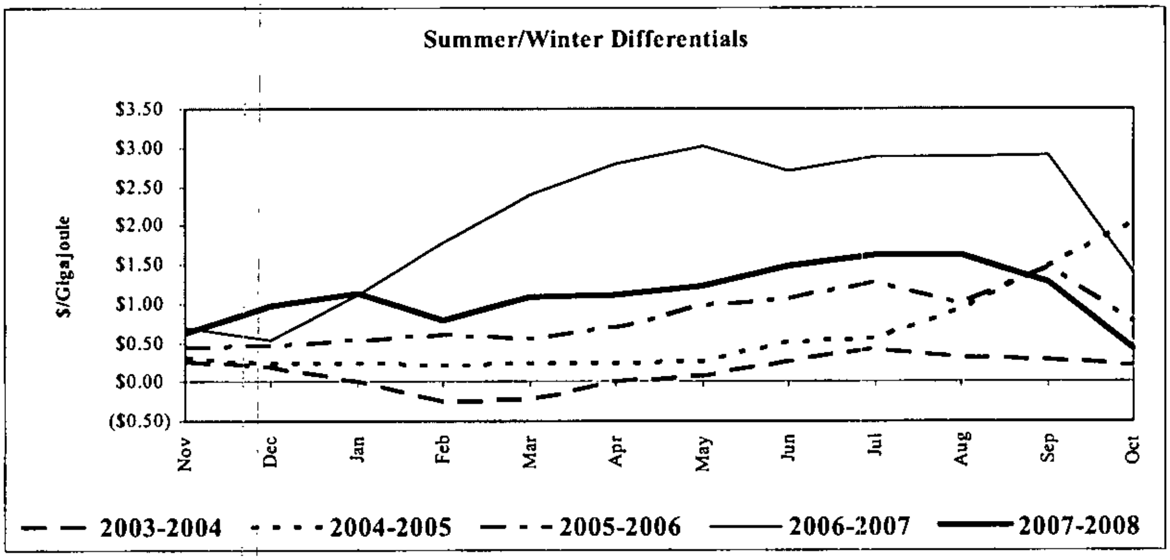
Note:
[1] The above chart represents measurements of Frac spreads in Alberta, as reported by an independent consultant.

Fluctuations in frac spreads affect ATCO Midstream's earnings and cash flow from operations. A $1.00 change in the average annual frac spread impacts annual earnings by approximately $6 million.

Storage Operations

The majority of ATCO Midstream's natural gas storage revenues come from seasonal differences (summer/winter) in the price of natural gas. Recognition of ATCO Midstream's revenues is determined through the terms of the contractual arrangements.

Summer/winter natural gas storage differentials can be volatile, as shown in the following graph, which illustrates a range of seasonal spreads experienced during the storage periods from 2003-2004 to 2007-2008. Storage differentials at any point in time may not always be indicative of the storage revenues and earnings for the same period due to the types of contracts and the timing of revenue recognition associated with these contracts.



ATCO Midstream faces risks associated with natural gas commodity prices volatility due to weather related supply and demand. To mitigate this risk ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for its storage operations.

In the fourth quarter of 2007, ATCO Midstream purchased a 50% interest in a joint venture which owns and operates a 2.5 million cubic feet per day natural gas processing plant near Kisbey, Saskatchewan, and 22 kilometres of pipeline serving four regional natural gas producers. Bayhurst Energy Services Corporation, a subsidiary of SaskEnergy Incorporated, owns the remaining interest in the joint venture and operates the plant, with ATCO Midstream providing operational and marketing support.

ATCO Frontec

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 North Warning System, Alaska Radar System and various remote sites for Northwestel Inc. in northern Canada. ATCO Frontec provides construction, site support and technical support for NATO, United Nations and the Swedish Armed Forces in Afghanistan and eastern Europe. ATCO Frontec also provides airport operation and maintenance, facilities management, bulk fuel storage and distribution and a wide variety of services and business activities in numerous locations throughout Canada. A number of the Canadian operations are conducted with a variety of aboriginal partners throughout Canada's north.

The following is a summary of the principal contracts which provide significant contributions to ATCO Frontec's earnings:

Contract	Customer	Start Date	Completion Date	Possible Extension [1]
Alaska Radar System [2]	U.S. Department of Defense	Oct. 2004	Sep. 2008	2014
North Warning System [2]	Department of National Defense	Sep. 2001	Sep. 2009	2011
Iqaluit Fuel Contract [2]	Government of Nunavut	Jun. 2007	Nov. 2012	2017
Stabilization Force Organization	NATO	Feb. 2004	Nov. 2008	-
Kabul International Airport	NATO	Feb. 2005	Mar. 2008	yr to yr
NATO Flight Training	NATO	Jun. 2000	May 2020	-
Kandahar Projects	NATO	Sep. 2007	Sep. 2010	2012

Notes:
(1) The contract may be extended at the option of the customer.
(2) Joint venture with aboriginal partners.

Recent Developments

In June 2007, ATCO Frontec was awarded five NATO support contracts at the Kandahar Airfield in Afghanistan for up to five years. Specific sectors of responsibility include fire and crash rescue, visiting aircraft services, roads and grounds maintenance, facility maintenance, construction, engineering, equipment and vehicle maintenance, aircraft movement control and terminal transport, accommodation services, supply operations, airfield mechanical transport, delivery of potable water, sewage management, and waste management and disposal.

In June 2007, UQSUQ Corporation, a joint venture between ATCO Frontec and Nunavut Petroleum Corporation, was awarded a five year contract renewal to lease and operate the 79 million litre bulk fuel storage facility, the pipeline distribution system, and the municipal fuel distribution system in Iqaluit, Nunavut.

On October 17, 2007, ATCO Frontec entered into a limited partnership with the Fort McKay First Nation to construct, own and operate a 500-room lodge in Fort McMurray, Alberta. The Creeburn Lake Lodge, which will be assembled primarily using modules built by ATCO Structures, is scheduled for completion in the second quarter of 2008, with full operations scheduled for the third quarter of 2008. The lodge has been designed to allow for future expansion to 1,000 rooms.

ATCO I-Tek

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

ATCO I-Tek provides billing services, payment processing, credit, collection and call centre services to its clients. ATCO I-Tek currently provides such services to Direct Energy for its regulated retail and competitive energy supply businesses in Alberta. In addition, ATCO I-Tek also supplies distribution-related billing and customer care services to ATCO Gas and ATCO Electric. In 2007, ATCO I-Tek's call centre was named the top customer service provider in the North American energy sector by Service Quality Measurement Group Inc. for the second year in a row.

Direct Energy has entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek to provide billing and call centre services to ensure continued quality customer service. Direct Energy has the ability to terminate this contract after the fifth anniversary upon immediate payment of termination fees which decline over the remaining term of the contract. Based upon current customer counts and service levels and a 10 year contract, revenues are estimated to be between $400-$500 million over the term of the contract.

Corporate and Other

Earnings for 2007 were $3.1 million, an **increase** of $14.8 million (126.5%) over 2006, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2007, **Adjusted Earnings** were $(5.6) million, an **increase** of $6.5 million (53.7%) over 2006. The primary reasons for the higher Adjusted Earnings in 2007 were lower share appreciation rights expense resulting from changes in Canadian Utilities Class A non-voting share and ATCO Class I Share prices since December 31, 2006, and increased income earned on cash balances due to higher short term interest rates.

Liquidity and Capital Resources

A major portion of the Company's operating income and funds generated by operations is generated from its Utility operations. Canadian Utilities and CU Inc., a wholly owned subsidiary of Canadian Utilities, use commercial paper borrowings and short term bank loans to provide flexibility in the timing and amounts of long term financing.

SUMMARY OF CASH FLOW	For the Year Ended December 31		
($ millions)	**2007**	2006	Change to 2007 (2007-2006)
Cash position, beginning of period	**798.8**	824.4	(3.1)%
Cash provided by (used in)			
Operating activities	**706.9**	617.9	14.4%
Investing activities	**(642.1)**	(527.5)	21.7%
Financing activities	**(98.8)**	(132.3)	25.3%
Foreign currency impact on cash balances	**(17.6)**	16.3	(208.0)%
Cash position, end of period	**747.2**	798.8	(6.5)%

OPERATING ACTIVITIES

Cash flow from operations increased by 14.4% in 2007, primarily due to increases in funds generated by operations. **Funds generated by operations** increased by 10.4% in 2007 primarily due to higher earnings and increased deferred availability incentives in Alberta Power (2000).

INVESTING ACTIVITIES

In 2007, cash used in **investing activities increased** 21.7% primarily due to higher capital expenditures in 2007, and changes in non-current deferred electricity costs. Capital expenditures increased by $133.1 million primarily due to:

- increased investment in regulated electric distribution and transmission and regulated natural gas distribution projects; and
- increased investment in ATCO Frontec projects.

CAPITAL EXPENDITURES	For the Year Ended December 31		
($ millions)	**2007**	2006	Change to 2007 (2007-2006)
Utilities	**588.9**	505.0	16.6%
Power Generation	**49.2**	48.1	2.3%
Global Enterprises	**62.7**	14.2	341.5%
Corporate and Other	**-**	0.4	(100.0)%
	700.8	567.7	23.4%

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately $0.9 billion in 2008, an increase of 28.4% from 2007. The majority of these expenditures are uncommitted and relate primarily to the Utility operations. Capital expenditures for 2008 to 2010 are expected to be approximately $3.0 billion for the Utilities segment.

FINANCING ACTIVITIES

In 2007, the Company had **net debt increases** of $82.2 million. **Issuance** of debt included $220.0 million of 5.556% Debentures due October 2037, and $35.0 million of 4.883% Debentures due November 2012. **Redemptions** were comprised of $50.0 million of 4.801% Debentures due November 2007 and $122.8 million of non-recourse long term debt, including a one time payment of $52.7 million which represented the company's portion of proceeds from the TXU settlement applied to Barking Power's non-recourse long term debt.

On April 18, 2007, CU Inc., a subsidiary company, issued $115.0 million of Cumulative Redeemable Preferred Shares Series 1 at a price of $25.00 per share for cash. The dividend rate was fixed at 4.60%. The net proceeds of the issue were used in part to redeem, on May 18, 2007, $91.8 million of the outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S of ATCO Electric, ATCO Gas and ATCO Pipelines, subsidiaries of CU Inc., that were held by the Company. On May 18, 2007, the Company redeemed all of the $126.5 million outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S at a price of $25.00 per share plus accrued and unpaid dividends. These changes resulted in a net equity preferred share decrease of $11.5 million.

The dividend rate on the Perpetual Cumulative Second Preferred Shares Series V was reset to $1.18 (from 5.25% to 4.70%) for the period between October 3, 2007 and October 3, 2012.

Purchases of Canadian Utilities' Class A non-voting shares under normal course issuer bids amounted to $8.0 million and issues of Canadian Utilities' Class A non-voting shares due to stock option exercises amounted to $1.6 million for a net change of $6.4 million, a net decrease of $61.1 million from 2006.

On May 23, 2006, Canadian Utilities Limited commenced a **normal course issuer bid** for the purchase of up to 5% of the outstanding Class A shares. The bid expired on May 22, 2007. Over the life of the bid, 1,679,700 shares were purchased, all of which were purchased in 2006. On May 23, 2007, Canadian Utilities commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2008. From May 23, 2007, to February 15, 2008, 157,800 shares have been purchased, all of which were purchased in 2007.

Dividends paid to Class A and Class B share owners **decreased** 11.3% to $156.8 million due to the one-time special dividend paid in 2006. In the first quarter of 2007, the dividend was **increased** by $0.015 to $0.305 per share. For the second, third and fourth quarters the dividend was **increased** by $0.01 to $0.315 per share. The Company has increased its annual common share dividend each year since its inception as a holding company in 1972. At their meeting in the first quarter of 2008, the Board of Directors **increased** the quarterly dividend by $0.0175 to $0.3325. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Company and other factors.

On October 18, 2007, Standard and Poor's announced that it had upgraded its rating on Canadian Utilities' unsecured long term debt from A- to A.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation negatively impacted the Company's cash position by $33.9 million as a result of changes in U.K. and Australian exchange rates used for balance sheet translations.

SHORT TERM INVESTMENT POLICY

It is the Company's policy to not invest any of its cash balances in asset-backed commercial paper.

LINES OF CREDIT

At December 31, 2007, the Company had the following credit lines that enable it to obtain funding for general corporate purposes.

($ millions)	Total	Used	Available
Long term committed	326.0	48.2	277.8
Short term committed	600.0	10.0	590.0
Uncommitted	74.1	12.9	61.2
Total	1,000.1	71.1	929.0

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

CONTRACTUAL OBLIGATIONS

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

	Payments Due by Period				
($ millions)	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
Long term debt	2,603.2	100.0	254.5	182.0	2,066.7
Non-recourse long term debt	543.5	65.4	96.3	81.1	300.7
Operating leases	61.7	16.3	20.1	11.7	13.6
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1)	3.5	0.5	1.0	1.0	1.0
Alberta Power (2000) coal purchase contracts (2)	554.6	49.3	101.7	107.3	296.3
ATCO Power natural gas fuel supply contracts (3)	183.5	49.8	98.2	30.2	5.3
Alberta Power (2000) and ATCO Power operating and maintenance agreements (4)	154.5	19.4	34.4	31.8	68.9
Capital expenditures (5)	84.4	84.4	-	-	-
Other	7.0	3.9	2.3	0.6	0.2
Total	4,195.9	389.0	608.5	445.7	2,752.7

Notes:

(1) ATCO Gas has ongoing 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. These obligations relate primarily to operational contracts pertaining to the Carbon natural gas storage facility, which continues to be subject to AUC regulation. 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, 2007, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. Direct Energy has agreed to purchase the natural gas purchased under these contracts at the prices paid by 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 PPAs.

(3) ATCO Power has various contracts to purchase natural gas for certain of its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 78% of these costs. The balance of 22%, related to ATCO Power's Barking generating plant, is recovered through merchant sales in the U.K. electricity market. The ATCO Power and ATCO Resources merchant component of their generating plants in Alberta do not have any long term contracts to purchase natural gas.

(4) Alberta Power (2000) and ATCO Power have various contracts with suppliers to provide operating and maintenance services at certain of their generating plants.

(5) Various contracts to purchase goods and services with respect to capital expenditure programs.

CURRENT AND LONG TERM FUTURE INCOME TAX LIABILITY

Current and long term future income tax liabilities of $155.5 million at December 31, 2007, 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.

BASE SHELF PROSPECTUS

On April 12, 2006, CU Inc. filed a **base shelf prospectus** which permits CU Inc. to issue up to an aggregate of $850.0 million of debentures over the twenty-five month life of the prospectus. As at December 31, 2007 the following debentures had been issued:

- on November 20, 2006, CU Inc. issued $160.0 million of 4.801% Debentures due November 22, 2021, at a price of 100 to yield 4.801% and $160.0 million of 5.032% Debentures due November 20, 2036, at a price of 100 to yield 5.032%. The proceeds of these two issues were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines for use in funding capital expenditures, repay indebtedness and for other general corporate purposes.
- on November 1, 2007, CU Inc. issued $220.0 million of 5.556% Debentures due October 30, 2037, at a price of 100 to yield 5.556%. The proceeds of this issue were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines for use in funding capital expenditures, repay indebtedness and for other general corporate purposes.
- on November 1, 2007, CU Inc. issued $35.0 million of 4.883% Debentures due November 1, 2012, at a price of 100 to yield 4.883%. The proceeds of this issue were advanced to Alberta Power (2000) for use in funding capital expenditures, repay indebtedness and for other general corporate purposes.

Share Capital

The equity securities of the Company consist of Class A shares and Class B shares.

At February 15, 2008, the Company had outstanding 81,555,386 Class A shares, 43,739,284 Class B shares, and options to purchase 1,304,200 Class A shares.

CLASS A NON-VOTING SHARES AND CLASS B VOTING 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 Company on either of such classes of shares as well as the remaining property of the Company 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 Company, 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 Company if ATCO Ltd., the present controlling share owner of the Company, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares of the Company. 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.

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 3,122,200 Class A non-voting shares are available for issuance at December 31, 2007. 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. As of February 15, 2008, options to purchase 1,304,200 Class A shares were outstanding.

Business Risks

ENVIRONMENTAL MATTERS

Canadian Utilities' 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.

On April 26, 2007, the federal government released a plan that proposes mandatory GHG emission targets on industry. The proposed plan requires an initial reduction in 2010 of 18% from 2006 levels followed thereafter by annual reductions of an additional 2%. New facilities (2004 or later) are allowed a 3-year grace period after which they must improve emission intensity by 2% per year below the clean fuel standard. Compliance may be achieved by reduction or capture, limited investment in a technology fund, emission credit trading, purchase of offset credits, *Kyoto Protocol Clean Development Mechanisms* (maximum 10%) and very limited opportunity for early action credits. Specific details on the regulations have yet to be released and will be required to assess the financial impact of the federal framework. It is anticipated that the PPAs will allow the Company to recover most of the costs associated with complying with the new regulations.

On April 20, 2007 and June 27, 2007, respectively, the Government of Alberta approved Bill 3, Climate Change and Emissions Management Amendment Act and the Specified Gas Emitters Regulation Amendment that requires Alberta facilities that emit 100,000 tonnes or more of GHG to reduce facility emission intensities by 12% starting July 1, 2007. Units commissioned before January 1, 2000, or that have less than nine years of commercial operation are required to reduce their emission intensity by 2% per year starting in the fourth year of commercial operation to a maximum of 12% in the ninth year of commercial operation. Cogeneration units with emissions less than a deemed emission target based on a stand-alone natural gas combined cycle unit and conventional boiler will be eligible for credits. It is anticipated that the PPAs will allow the Company to recover most of the costs associated with complying with the new regulations.

The Alberta government implemented a mercury emission regulation in March 2006. The regulation requires coal-fired plant operators, including Alberta Power (2000), to monitor mercury emissions and capture at least 70% of the mercury in the coal starting January 1, 2011. It is anticipated that the PPAs will allow the Company to recover most of the costs associated with complying with the new regulation.

REGULATED OPERATIONS

Regulated operations are conducted by Canadian Utilities' wholly owned subsidiary CU Inc., which in turn has the following subsidiaries: ATCO Electric and its subsidiaries, ATCO Gas, ATCO Pipelines, and CU Water. Alberta Power (2000)'s two largest generating plants are also considered regulated operations because they are governed by legislatively mandated PPAs, approved by the AUC.

ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water are regulated primarily by the AUC, which administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area. The AUC may approve interim rates or approve the recovery of costs, including capital and operating costs, on a placeholder basis, 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 AUC 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. In addition, these risks include the disallowance by the AUC, of costs incurred. The Company'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.

Carbon Natural Gas Storage Facility

ATCO Gas leases the entire storage capacity of the Carbon natural gas storage facility to ATCO Midstream at AUC approved placeholder rates. On February 5, 2007, the AUC issued a decision to ATCO Gas that leaves in question these placeholder rates and the effect that these placeholder rates will have on future ATCO Gas revenues.

Temperatures

Temperature fluctuations have a significant impact on throughput in ATCO Gas. As approximately 50% of ATCO Gas' delivery charge is recovered based on throughput, ATCO Gas' revenues and earnings are sensitive to temperature. Temperatures that are 10% warmer or colder than normal temperatures impact ATCO Gas' annual earnings by approximately $9.7 million.

As part of its 2008 and 2009 general rate application filed with the AUC in November 2007, ATCO Gas is seeking approval from the AUC to set up a deferral account mechanism which would, if approved, eliminate the impact of temperature on ATCO Gas' earnings.

Benchmarking

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process. A benchmarking report was received on January 23, 2008, and an application is anticipated to be made to the AUC by the end of February 2008 to finalize the placeholder costs. An AUC decision is expected before the end of the second quarter of 2008.

Transfer of the Retail Energy Supply Businesses

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy and one of its affiliates (collectively Direct Energy), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Although ATCO Gas and ATCO Electric transferred to Direct Energy certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if Direct Energy fails to perform. In certain events (including where Direct Energy fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AUC to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to Direct Energy by ATCO Gas and/or ATCO Electric.

Centrica plc, Direct Energy's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of Direct Energy's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek's payment and indemnity obligations to Direct Energy contemplated under the transaction agreements.

Late Payment Penalties on Utility Bills

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

Measurement Inaccuracies in Metering Facilities

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow up are found to be inadequate by the AUC.

An AUC decision applicable to ATCO Gas established a two-year adjustment limitation period for inaccuracies in gas supply costs, including measurement inaccuracies in metering facilities. The AUC stated that it will consider specific applications for adjustments beyond the two-year limitation period.

Alberta Power (2000)

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

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, 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 Government of 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 PPAs were based.

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.

NON-REGULATED OPERATIONS

ATCO Power

The Company'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 Company, under these agreements, assumes the operating risks.

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 2007, sales from approximately 71% of ATCO Power's and ATCO Resources Ltd's, (a wholly owned subsidiary of ATCO Ltd.), generating capacity were subject to long term agreements, while the remaining 29% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. In 2008, these percentages are expected to be approximately the same. These sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool 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 good 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.

Changes and volatility in Alberta Power Pool electricity prices, natural gas prices and related Spark spreads may have a significant impact on the Company's earnings and cash flow from operations in the future. The Company has adopted asset optimization strategies for bidding its merchant power into the Alberta and U.K. power markets.

Since October 2004, the output from ATCO Power's Barking generating plant previously sold to TXU Europe has been sold into the U.K. power exchange market. In the U.K., electricity generators, on average, sell over 90% of their output to electricity suppliers in bilateral contracts, with the remaining output sold via various power pool mechanisms. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants. The Barking generating plant has a long term, fixed price gas purchase agreement and, as a result, has been able to experience increased margins due to the high market prices for electricity. Changes in the U.K. market electricity prices may have an impact on the Company's earnings and cash flow from operations in the future.

ATCO Power and ATCO Resources have financed their 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 Company's equity therein. Canadian Utilities has provided a number of guarantees related to ATCO Power's and ATCO Resources' obligations under their respective non-recourse loans associated with certain of their projects. ATCO Power (80%) and ATCO Resources (20%) have a joint venture in these projects subject to guarantees, excluding Barking Power. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest. The guarantees outstanding at December 31, 2007, are described in Note 12 to the consolidated financial statements. To date, Canadian Utilities has not been required to make any payments related to its guaranteed obligations.

The Company's generating plants are exposed to operational risks which may cause outages due to such issues as boiler and turbine failures. In order to mitigate this risk, a proactive maintenance program is carried out on a regular basis with scheduled outages for major overhauls and other maintenance issues. In addition, the Company carries property and business interruption insurance to protect against the risk of extended outages.

ATCO Midstream

ATCO Midstream is exposed to the difference between the selling prices of the NGL produced and the purchase price of shrinkage gas. The amount of profit made from ATCO Midstream's NGL extraction operations will increase or decrease as the difference between the price of NGL and natural gas commodities increases or decreases.

ATCO Midstream is exposed to seasonal natural gas price spreads. The amount of earnings and cash flow from the storage business will vary as the differences between the price of natural gas in the summer and the following winter fluctuates. To mitigate this risk ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for the storage operations.

In June 2007, the AUC initiated an industry wide review of NGL extraction rights as the existing industry agreement expires in 2008. The process is ongoing and is expected to be completed in 2008. The impact to ATCO Midstream's earnings and cash flow from operations is uncertain at this time.

ATCO Frontec

ATCO Frontec's operations include providing support to military agencies in foreign locations which may be subject to military risk. ATCO Frontec maintains insurance to mitigate the risk associated with the nature of these contracts. Additionally, in areas where the risk of injury is considered to be severe, ATCO Frontec confines its staff to specific military compounds and all employees are given pre-deployment orientation and ongoing safety training.

A fuel spill occurred in January 2007 at the Brevoort Island, Northwest Territories, radar site maintained by Nasittuq Corporation, a corporation jointly owned by ATCO Frontec and Pan Arctic Inuit Logistics Corporation. ATCO believes that it has sufficient insurance coverage in place to cover any material amounts that might become payable as a result of the fuel spill. Accordingly, this spill is not expected to have any material impact on Canadian Utilities' financial position.

ATCO I-Tek

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AUC approval after completion of a collaborative benchmarking process. A benchmarking report was received on January 23, 2008.

Adjustments to ATCO I-Tek's fees as a result of the benchmarking report for information technology services will be retroactive to January 1, 2008. Price changes relating to ATCO I-Tek's customer care and billing contract services for ATCO Gas and ATCO Electric will be applied following renegotiation of a new fee schedule. The final impact of the benchmarking report may result in reduced revenues for ATCO I-Tek in 2008 and beyond for services provided to ATCO Electric, ATCO Gas, and ATCO Pipelines.

Derivative Financial Instruments

In conducting its business, the Company 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. For details on the financial instruments in place at December 31, 2007, see Note 21 to the consolidated financial statements.

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

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

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

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

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

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

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

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:

(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,

(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

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

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

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

Transactions with Related Parties

The Company's transactions with related parties are in the normal course of business and under normal commercial terms. For a description of these transactions, see Note 19 to the consolidated financial statements.

Off-Balance Sheet Arrangements

At December 31, 2007, unrecorded future income tax liabilities of the regulated operations amounted to $159.4 million and unrecorded future income tax assets of other operations amounted to $0.8 million. The liabilities include $4.7 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. There are tax loss carryforwards of $0.4 million for Canadian subsidiary companies and $4.6 million for a foreign subsidiary company for which no tax benefit has been recorded. The losses for the Canadian subsidiary companies begin to expire in 2010, and the losses for the foreign subsidiary company does not expire. For additional information on the Company's unrecorded future income tax liabilities (refer to Note 6 to the consolidated financial statements).

Other than the financial instruments discussed under the Derivative Financial Instruments section, the Company 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.

Contingencies

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

Critical Accounting Estimates

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

DEFERRED AVAILABILITY INCENTIVES

Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPAs. Each quarter, management uses these estimates to forecast high case, low 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. As at December 31, 2007, the Company had recorded $41.8 million of deferred availability incentives. The amortization of deferred availability incentives recorded in revenues amounted to $11.8 million in 2007.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately $5.3 million, whereas the low case scenario would have resulted in lower revenues of approximately $5.3 million.

EMPLOYEE FUTURE BENEFITS

The expected long term rate of return on pension plan assets is determined at the beginning of the year on the basis of the long bond yield rate 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 1.5%, which, when added to the long bond yield rate of 5.1% at the beginning of 2007, resulted in an expected long term rate of return of 6.6% for 2007. This methodology is supported by actuarial guidance on long term asset return assumptions for the Company'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 expected long term rate of return has declined over the past six years, from 8.1% in 2001 to 6.6% in the year ended December 31, 2007. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the same period has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

The liability discount rate that is used to calculate the cost of benefit obligations reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate has also declined over the same period, from 6.9% at the end of 2001 to 5.5% at the end of 2007. The result has been an increase in benefit obligations (i.e., an experience loss), which is contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

In accordance with the Company's accounting policy to amortize cumulative experience gains and losses in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, the Company began amortizing a portion of the net cumulative experience losses on plan assets and accrued benefit obligations in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization in 2007.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the year ended December 31, 2007, are as follows: for drug costs, 7.8% starting in 2007 grading down over six years to 4.5%, and for other medical and dental costs, 4.0% for 2007 and thereafter. Combined with lower recent claims experience, the effect of these changes has been to decrease the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AUC 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 cost (income) for 2007 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.

	2007 Pension Benefit Plans		**2007 Other Post Employment Benefit Plans**	
($ millions)	**Accrued Benefit Obligation**	**Benefit Plan Cost**	**Accrued Benefit Obligation**	**Benefit Plan Cost**
Expected long term rate of return on plan assets				
1% increase (1)	-	(4.0)	-	-
1% decrease (1)	-	4.0	-	-
Liability discount rate				
1% increase (1)	(82.3)	(5.6)	(3.7)	(0.3)
1% decrease (1)	104.9	8.4	4.6	0.4
Future compensation rate				
1% increase (1)	21.9	3.0	-	-
1% decrease (1)	(20.1)	(2.8)	-	-
Long term inflation rate				
1% increase (1)(2)(3)	36.5	4.5	3.9	0.6
1% decrease (1)(3)	(63.8)	(7.7)	(3.1)	(0.4)

Notes:

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

(2) The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.

(3) 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.

Changes in Accounting Policies

Effective January 1, 2007, the Company adopted the CICA recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity, and other financial liabilities are measured at their amortized cost. This change in accounting had the following effect on the consolidated financial statements for the three months and year ended December 31, 2007:

- Recognition of interest rate swaps, foreign currency forward contracts and certain natural gas purchase contracts as derivative assets and liabilities in the consolidated financial statements (see Note 21 to the consolidated financial statements).
- Recognition of the fair value of a power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (see Note 21 to the consolidated financial statements).
- Recognition of a Mark-to-Market Adjustment for the change in fair value of the natural gas purchase contracts derivative asset and recognition of an adjustment to the associated power generation revenue contract liability (see Note 5 to the consolidated financial statements).
- Restatement of opening retained earnings at January 1, 2007 to recognize the prior years' earnings effect of the natural gas purchase contracts derivative asset and the associated power generation revenue contract liability, as well as the prior years' earnings effect of accounting for certain financial assets and financial liabilities at amortized cost using the effective interest method (see Note 7 to the consolidated financial statements).
- Reclassification of deferred financing charges from other assets to long term debt and non-recourse long term debt (see Note 12 to the consolidated financial statements).

Effective January 1, 2007, the Company adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the consolidated financial statements for the three months and year ended December 31, 2007.

Effective January 1, 2007, the Company adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Company from sources other than the Company's share owners, and includes earnings of the Company, the foreign currency translation adjustment relating to self-sustaining foreign operations and unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the consolidated financial statements.

Effective January 1, 2007, the Company adopted the CICA recommendations regarding the presentation of equity and changes in equity. These recommendations require separate presentation of the components of equity, including retained earnings, accumulated other comprehensive income, contributed surplus, share capital and reserves, and the changes therein. As a result of this change in accounting, the Company has included a reconciliation of accumulated other comprehensive income in the notes to the consolidated financial statements (see Note 22 to the consolidated financial statements). In accordance with the recommendations, comparative figures have been adjusted to incorporate the foreign currency translation adjustment into accumulated other comprehensive income.

Effective January 1, 2007, the Company adopted the CICA recommendations that prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. Adoption of these recommendations had no effect on the consolidated financial statements for the three months and year ended December 31, 2007, except for the disclosure of accounting changes that have been issued by the CICA but have not yet been adopted by the Company because they are not effective until a future date (see Future Accounting Changes section).

FUTURE ACCOUNTING CHANGES

The CICA has issued new accounting recommendations for capital disclosures which require disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the Company's objectives, policies and processes for managing capital. These recommendations are effective for the Company beginning January 1, 2008. This recommendation requires additional disclosure in the notes to the financial statements.

The CICA has issued new accounting recommendations for disclosure and presentation of financial instruments which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks arising from financial instruments to which the Company is exposed. These recommendations are effective for the Company beginning January 1, 2008. This recommendation requires additional disclosure in the notes to the financial statements.

The CICA has issued new accounting recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any writedown to net realizable value, and on the cost formulas that are used to assign costs to inventories. The adoption of these recommendations is not expected to have a material impact on the earnings or assets of the Company. These recommendations are effective for the Company beginning January 1, 2008.

The CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. The Company is evaluating the possibility of using standards issued by the Financial Accounting Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of GAAP. At this time the Company is unable to determine the effect that this decision will have on earnings or assets and liabilities of the Company. The CICA has also issued new recommendations pertaining to regulated income taxes to require the recognition of future regulated income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. These recommendations are effective for the Company beginning January 1, 2009, and will be applied prospectively. This recommendation requires additional disclosure in the notes to the financial statements; however, the company believes that there will be no material impact on its earnings.

In 2006, the CICA announced that accounting standards in Canada are to converge with International Financial Reporting Standards ("IFRS"). The Company will need to begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to GAAP, but there are significant differences on recognition, measurement and disclosures that will need to be addressed. The Company is currently assessing the impact of these standards on its financial statements.

Quarterly Results of Operations

SELECTED INFORMATION

($ millions except per share data)	For the Three Months Ended				
	Mar 31	Jun 30	Sep 30	Dec 31	Total
			(unaudited)		
2007 (1) (2) (3)					
Revenues	697.6	560.3	489.9	657.1	2,404.9
Earnings attributable to Class A and Class B shares	134.7	81.1	72.2	98.7	386.7
Earnings per Class A and Class B share	1.07	0.65	0.58	0.78	3.08
Diluted earnings per Class A and Class B share	1.07	0.64	0.58	0.78	3.07
Adjusted Earnings (4)	130.2	67.5	70.6	75.5	343.8
Adjusted Earnings per Class A and Class B share (4)	1.04	0.54	0.56	0.60	2.74
2006 (1) (2) (3)					
Revenues	642.0	563.4	553.9	671.1	2,430.4
Earnings attributable to Class A and Class B shares	86.9	70.2	66.8	100.0	323.9
Earnings per Class A and Class B share	0.68	0.56	0.53	0.80	2.57
Diluted earnings per Class A and Class B share	0.68	0.55	0.53	0.80	2.56
Adjusted Earnings (4)	86.9	66.4	67.5	100.0	320.8
Adjusted Earnings per Class A and Class B share (4)	0.68	0.52	0.54	0.80	2.54

Notes:

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

(2) Due to the seasonal nature of the Company's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees and the timing of rate decisions, revenues, earnings and Adjusted Earnings for any quarter are not necessarily indicative of operations on an annual basis.

(3) The above data (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B share) has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

(4) Refer to Significant Non-Operating Financial Items section for a description of adjustments made to earnings attributable to Class A and Class B shares to obtain Adjusted Earnings.

The principal factors that caused variations in **financial condition** and **results of operations** over the past eight quarters were:

- unplanned outage in ATCO Power's Barking generating plant in the fourth quarter of 2007 resulting in a $8.6 million reduction in earnings compared to the same period in 2006;
- the timing of utility rate decisions;
- amount of franchise fees collected by ATCO Gas on behalf of cities and municipalities;
- availability of power generating plants in ATCO Power and Alberta Power (2000);
- TXU Europe Energy Trading Limited (TXU Europe settlement);
- fluctuations in temperatures, natural gas prices, electricity prices and related Spark spreads in Alberta and the U.K.;
- changes in market conditions in ATCO Midstream's NGL and storage operations;
- changes in business activity in ATCO Frontec;
- exchange rates;
- H.R. Milner Income Tax Reassessment in Alberta Power (2000) in 2006;
- 2006 and 2007 Changes in Income Taxes and Rates;
- 2007 Changes in the Taxation of Preferred Share Dividends;
- ATCO Gas Tax Reassessments; and
- changes in share appreciation rights expense due to changes in Canadian Utilities Class A non-voting share and ATCO Ltd. Class I Share prices.

Fourth Quarter 2007

All quarterly information in this document is unaudited and has been shaded to differentiate it from the annual information.

SEGMENTED REVENUE	For the Three Months Ended December 31		
($ millions)	**2007**	2006	Change to 2007 (2007-2006)
		(unaudited)	
Utilities	**313.3**	314.7	(0.4)%
Power Generation	**193.9**	226.7	(14.5)%
Global Enterprises	**198.2**	173.9	14.0%
Corporate and Other	**3.5**	3.3	6.1%
Intersegment eliminations	**(51.8)**	(47.5)	9.1%
Revenues	**657.1**	671.1	(2.1)%

Notes:

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

(2) Due to the seasonal nature of the Company's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees and the timing of rate decisions, revenues for any quarter are not necessarily indicative of operations on an annual basis.

(3) The above data has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

Fourth quarter **revenues decreased** by $14.0 million primarily due to:

- lower sales in ATCO Power's Alberta generating plants due to lower Alberta Power Pool prices; and
- the impact of a fourth quarter outage at the Barking generating plant in ATCO Power's U.K. operations.

These decreases were partially offset by:

- higher prices and volumes of natural gas processed for NGL extraction operations in ATCO Midstream; and
- the recording of GHG emission fees by Alberta Power (2000) recovered from its customers in accordance with the PPAs which cover costs of recent changes in environmental laws (refer to Business Risks - Environmental Matters section).

Temperatures in ATCO Gas for the three months ended December 31, 2007, were 0.8% colder than normal, compared to 5.2% colder than normal in 2006.

SEGMENTED EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES	**For the Three Months Ended December 31**		
($ millions)	**2007**	2006	Change to 2007 (2007-2006)
		(unaudited)	
Utilities	**48.0**	43.7	9.8%
Power Generation	**25.5**	36.9	(30.9)%
Global Enterprises	**27.7**	27.3	1.5%
Corporate and Other	**(4.1)**	(6.5)	(36.9)%
Intersegment eliminations	**1.6**	(1.4)	214.3%
Earnings attributable to Class A and Class B shares	**98.7**	100.0	(1.3)%
Earnings per Class A and Class B share	**0.78**	0.80	(2.5)%
Diluted earnings per Class A and Class B share	**0.78**	0.80	(2.5)%
Adjusted earnings per Class A and Class B share	**0.60**	0.80	(25.0)%

Notes:

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

(2) Due to the seasonal nature of the Company's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.

(3) The above data has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

RECONCILIATION OF EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES AND ADJUSTED EARNINGS	**For the Three Months Ended December 31**					
($ millions)	Utilities	Power Generation	Global Enterprises	Corporate & Other	Intersegment Eliminations	Total
2007						
Earnings attributable to Class A and Class B shares	**48.0**	**25.5**	**27.7**	**(4.1)**	**1.6**	**98.7**
2007 Changes in Income Taxes and Rates (2)	**(0.3)**	**(8.2)**	**-**	**-**	**(2.4)**	**(10.9)**
Mark-to-Market Adjustment	**-**	**(2.8)**	**-**	**-**	**-**	**(2.8)**
ATCO Gas Tax Reassessments	**(9.5)**	**-**	**-**	**-**	**-**	**(9.5)**
Adjusted Earnings	**38.2**	**14.5**	**27.7**	**(4.1)**	**(0.8)**	**75.5**
2006						
Earnings attributable to Class A and Class B shares	43.7	36.9	27.3	(6.5)	(1.4)	100.0
Adjusted Earnings	43.7	36.9	27.3	(6.5)	(1.4)	100.0

Notes:

(1) Refer to the Significant Non-Operating Financial Items section for a description of the items.

(2) In the fourth quarter an additional adjustment was made to reduce income tax expense relating to the impact of the income tax rate changes for the first nine months of 2007. This portion of the adjustment increased the Company's fourth quarter 2007 earnings by $1.5 million.

Fourth quarter **earnings were substantially unchanged** over 2006, including the impact of adjustments identified in the Significant Non-Operating Financial Items section.

Fourth quarter **Adjusted Earnings decreased** by $24.5 million (24.5%) over 2006 primarily due to:

- lower earnings in ATCO Power's Alberta generating plants due to lower spark spreads realized on sales of electricity;
- the impact of a fourth quarter outage at the Barking generating plant in ATCO Power's U.K. operations;
- increased operation and maintenance and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures; and
- warmer temperatures in ATCO Gas.

Partially offsetting the lower Adjusted Earnings were impacts from:

- higher prices and volumes of natural gas processed in NGL extraction operations in ATCO Midstream; and
- decreased share appreciation rights expense due to change in Canadian Utilities Class A non-voting share and ATCO Ltd. Class I Share prices since September 2007.

Alberta Power Pool electricity prices for the three months ended December 31, 2007, averaged $61.75 per MWh, compared to average prices of $116.81 per MWh for the corresponding period in 2006. Natural gas prices for the three months ended December 31, 2007, averaged $5.83 per GJ, compared to average prices of $6.55 per GJ for the corresponding period in 2006. The consequence of these changes in electricity and natural gas prices was an average spark spread of $18.00 per MWh for the three months ended December 31, 2007, compared to $67.66 per MWh for the corresponding period in 2006.

During the three months ended December 31, 2007, Alberta Power (2000)'s deferred availability incentive account increased by $4.5 million to $41.8 million. The increase was due to availability incentives earned in the quarter net of quarterly amortization. Amortization of deferred availability incentives, recorded in revenues, was $2.9 million, $0.2 million higher than the same period in 2006.

Interest and other income for the fourth quarter were positively impacted by increased income earned on cash balances due to higher short term interest rates and the Mark-to-Market Adjustment in ATCO Power.

OTHER EXPENSES	**For the Three Months Ended December 31**		
($ millions)	**2007**	2006	Change to 2007 (2007-2006)
		(unaudited)	
Operating expenses:			
Natural gas supply	**24.8**	10.2	143.1%
Purchased power	**13.6**	12.5	8.8%
Operation and maintenance	**251.4**	243.5	3.2%
Selling and administrative	**77.1**	74.9	2.9%
Franchise fees	**37.4**	42.4	(11.8)%
	404.3	383.5	5.4%
Depreciation and amortization expenses	**99.0**	95.6	3.6%
Interest expenses	**55.0**	54.6	0.7%
Income taxes	**13.1**	47.4	(72.4)%

Fourth quarter **operating expenses increased** by $20.8 million (5.4%) over 2006. Increased operating expenses were primarily due to higher prices and volumes of natural gas purchased for NGL extraction in ATCO Midstream higher operation and maintenance and selling and administrative expenses due to customer growth and increased business activity in ATCO Gas and ATCO Electric, higher operation and maintenance in ATCO Frontec due to increased international operations and the recording of GHG emission fees by Alberta Power (2000) recovered from its customers in accordance with the PPAs which cover costs of recent changes in environmental laws (refer to Business Risks - Environmental Matters section). These increases were offset by lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations and lower franchise fees collected by ATCO Gas on behalf of cities and municipalities.

Fourth quarter **depreciation and amortization** expenses increased as a result of increased capital additions in 2006 and 2007, mainly in the Utilities segment.

Interest expenses for the fourth quarter increased as a result of the new financings issued in 2006 and 2007, to fund capital expenditures in the Utilities operations, partially offset by the repayment of non-recourse long term debt in 2006 and 2007.

Income taxes in the fourth quarter decreased mainly due to the 2007 Changes in Income Taxes and Rates and the ATCO Gas Tax Reassessments.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CASH FLOW	For the Three Months Ended December 31		
($ millions)	**2007**	2006	Change to 2007 (2007-2006)
		(unaudited)	
Cash position, beginning of period	**682.9**	732.6	(6.8)%
Cash provided by (used in):			
Operating activities	**127.1**	119.9	6.0%
Investing activities	**(201.9)**	(160.6)	25.7%
Financing activities	**141.8**	95.3	48.8%
Foreign currency impact on cash balances	**(2.7)**	11.6	(123.3)%
Cash position, end of period	**747.2**	798.8	(6.5)%

OPERATING ACTIVITIES

Cash flow from operations for the fourth quarter increased by 6.0% primarily due to increases in funds generated by operations. **Funds generated by operations** increased by 6.9%, primarily due to increased deferred availability incentives in Alberta Power (2000).

INVESTING ACTIVITIES

Investing in the fourth quarter increased by 25.7%, primarily as a result of higher capital expenditures and changes in non-cash working capital. Increases in capital expenditures reflect increased investment in regulated electric distribution and transmission, regulated natural gas distribution and ATCO Frontec projects.

FINANCING ACTIVITIES

In the fourth quarter, the Company had **net debt increases** of $192.7 million. **Issuance** of debt included $220.0 million of 5.556% Debentures due October 2037 and $35.0 million of 4.883% Debentures due November 2012. **Redemptions** were comprised of $50.0 million of 4.801% Debentures due November 2007, and $12.3 million of non-recourse long term debt.

Fourth quarter **purchases** of Canadian Utilities' Class A non-voting shares under normal course issuer bids amounted to $8.0 million and issues of Canadian Utilities' Class A non-voting shares due to stock option exercises amounted to $0.3 million for a net change of $7.7 million.

FOREIGN CURRENCY TRANSLATION

Changes in U.K. and Australian exchange rates had a negative impact on the Company's cash position of $14.3 million.

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CANADIAN UTILITIES LIMITED
An ATCO Company

2007 ANNUAL INFORMATION FORM

February 19, 2008

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FORWARD-LOOKING INFORMATION

Certain statements contained in this Annual Information Form ("AIF") constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves 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 information. The Company believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

In particular, this AIF contains forward-looking information pertaining to, among other things, planned capital expenditures and the impact of changes in government regulation. Actual results could differ materially from those anticipated in this forward-looking information as a result of regulatory decisions, competitive factors in the industries in which the Company operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Company.

DEFINITIONS OF CERTAIN TERMS

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

"AESO" means the Alberta Electric System Operator;

"AGP" means ATCO Gas and Pipelines Ltd.;

"Alberta Power (2000)" means Alberta Power (2000) Ltd.;

"Alberta Power Pool" means the market for electricity in Alberta operated by the AESO;

"ASHCOR Technologies" means ASHCOR Technologies Ltd.;

"ATCO Electric" means ATCO Electric Ltd.;

"ATCO Energy Solutions" means ATCO Energy Solutions Ltd. (formerly ATCO Utility Services Ltd.);

"ATCO Frontec" means ATCO Frontec Corp. together with its subsidiaries;

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

"ATCO I-Tek" means ATCO I-Tek Inc.;

"ATCO Midstream" means ATCO Midstream Ltd.;

"ATCO Pipelines" means the natural gas transmission 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.;

"AUC" means the Alberta Utilities Commission and its predecessor, the Alberta Energy and Utilities Board;

"BPL" means Barking Power Limited;

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

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

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

"CU" means Canadian Utilities Limited;

"CU Water" means CU Water Limited;

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

"GHG" means any greenhouse gas which has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide and hydrofluorocarbons;

"GUA" means the Gas 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 AUC;

"NGL" means natural gas liquids, such as ethane, propane, butane and pentanes plus, that are extracted from natural gas and sold as distinct products or as a mix;

"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" means Power Purchase Arrangements that became effective on January 1, 2001, as part of the process of restructuring the electric utility business in Alberta. The PPAs are legislatively mandated and approved by the AUC;

"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;

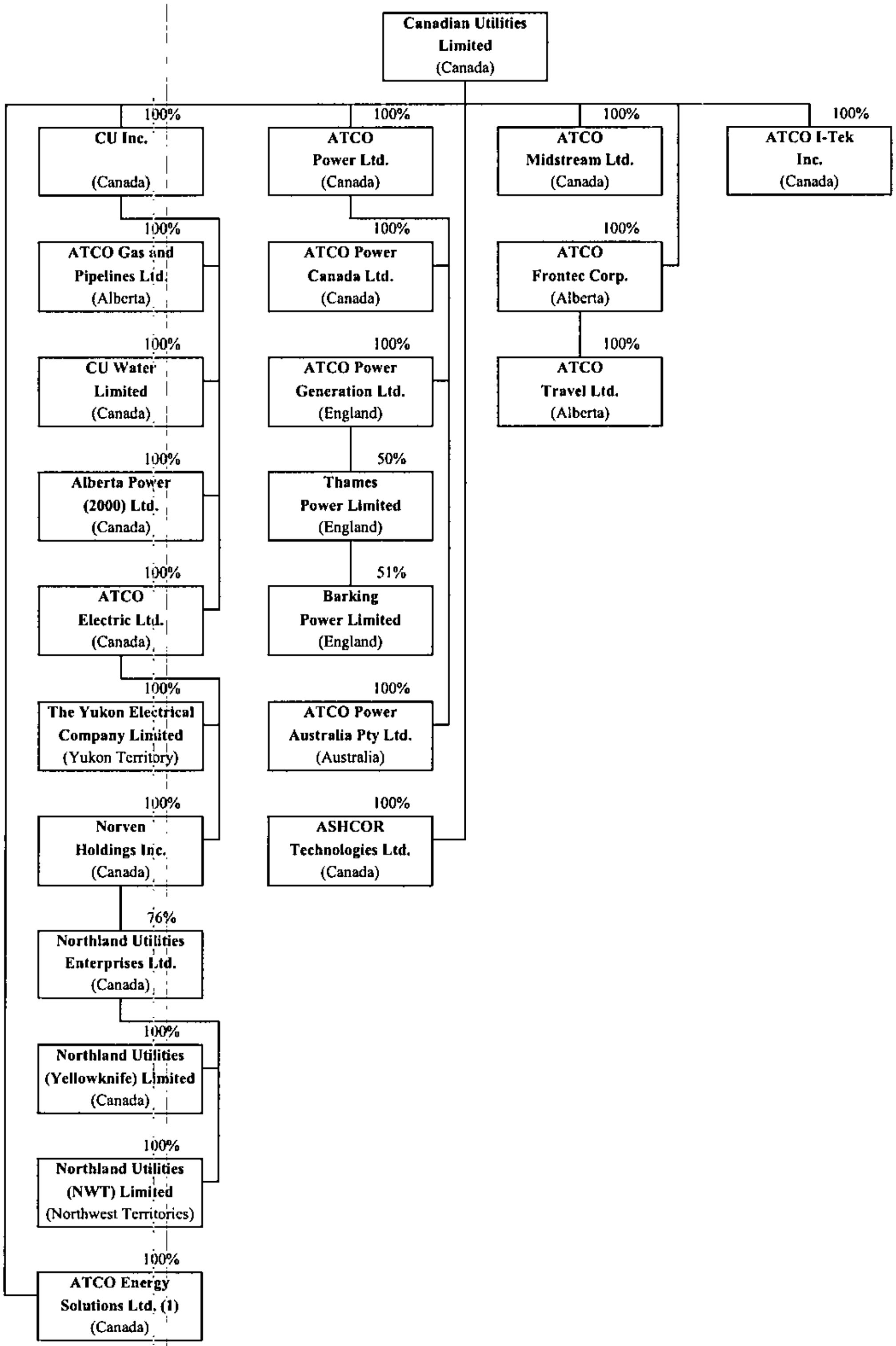
"U.K." means United Kingdom;

"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 Company was reorganized on September 10, 1982. The address of the principal office of the Company is 1600, 909 – 11th Avenue S.W., Calgary, Alberta T2R 1N6 and the registered office of the Company is 20th Floor, 10035 – 105 Street, Edmonton, Alberta, T5J 2V6.

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



<u>*Note:*</u>

(1) Effective January 24, 2008, ATCO Utility Services Ltd. changed its name to ATCO Energy Solutions Ltd.

BUSINESS OF THE COMPANY

The Company 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 (and its subsidiaries, NLD, NUY and YECL), ATCO Gas and ATCO Pipelines. Included in regulated operations are the generating plants of Alberta Power (2000), which were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are included in regulated operations primarily because the PPAs 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 PPAs. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPAs expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant and be responsible for decommissioning costs. For PPAs expiring after 2018, decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

The Company operates in the following business segments:

The Utilities Business Group includes:

- the regulated distribution of natural gas by ATCO Gas;
- the regulated transmission and distribution of water by CU Water;
- the regulated transmission of natural gas by ATCO Pipelines;
- the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical; and
- the provision of non-regulated complementary projects by ATCO Energy Solutions (formerly ATCO Utility Services).

The Power Generation Business Group includes:

- the non-regulated supply of electricity and cogeneration steam by ATCO Power;
- the regulated supply of electricity by Alberta Power (2000); and
- the sale of fly ash and other combustion byproducts produced in coal-fired electrical generating plants by ASHCOR Technologies.

The Global Enterprises Business Group includes:

- the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream;
- the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec;
- the development, operation and support of information systems and technologies, and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- the sale of travel services to both business and consumer sectors by ATCO Travel.

The Corporate and Other segment includes commercial real estate owned by the Company in Alberta.

Three Year History

The significant events and conditions that have influenced the general development of the Company's business over the past three years are summarized below.

2007:

- Increased business activity in ATCO Frontec.
- Increased capital expenditures in the Utilities Business Group.
- Fluctuations in temperatures affecting ATCO Gas' operations.
- In November 2007, the AUC announced that a generic return on common equity of 8.75% would be applied on rate applications filed for 2008. ATCO Gas and ATCO Pipelines have filed applications for 2008. ATCO Electric's 2008 general tariff application decision included a placeholder rate of return on common equity for 2008, with the generic rate for 2008 replacing the placeholder rate.
- Availability of generating plants in ATCO Power and Alberta Power (2000).
- On October 25, 2007, ATCO Power's 1,000 MW Barking generating plant in the U.K. experienced an unplanned outage due to failure in a steam turbine generator. This outage reduced the plant capacity to approximately 400 MWs during this period. The financial impact of the failure was a decrease to ATCO Power's 2007 earnings of approximately $8.6 million. Discussions have been ongoing with insurers and their advisers, who have endorsed the repair strategy and have approved interim payments which commenced in early 2008. As a result of the uncertainty of the timing of the units return to service and the ability to allocate the interim payment proceeds, ATCO Power's first quarter 2008 earnings may be lower as a result of this continuing situation.
- Volatility in prices received for electricity sold to the Alberta Power Pool by ATCO Power and for electricity sold into the United Kingdom Power Exchange Market by ATCO Power.
- Lower PPA tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate that is based on long term Government of Canada bond yields plus 4.5%. The rate of return on common equity for 2008 is 8.88%.
- Changes in market conditions in natural gas liquids and storage operations in ATCO Midstream.
- In June 2007, ATCO Frontec was awarded five NATO support contracts at the Kandahar Airfield in Afghanistan for up to five years. Specific sectors of responsibility include fire and crash rescue, visiting aircraft services, roads and grounds maintenance, facility maintenance, construction, engineering, equipment and vehicle maintenance, aircraft movement control and terminal transport, accommodation services, supply operations, airfield mechanical transport, delivery of potable water, sewage management, and waste management and disposal.
- In 2003, the federal government announced that the income tax deduction available to corporations that pay taxes on dividends on preferred shares (Part VI.1 tax) would be decreased from 9/4ths of the Part VI.1 tax paid to 9/3rds in 2003, but this change was not enacted by parliament until 2007. Accordingly, the

Company recorded a one-time reduction to current income tax expense which resulted in increased earnings of $15.6 million relating to years prior to 2007. An additional increase to earnings of $0.8 million was recorded relating to the first quarter of 2007. Funds generated by operations increased by $16.4 million, offset by a similar reduction in changes in non-cash working capital, leaving the Company's cash position unchanged.

- In 2007, the federal government announced a reduction in corporate tax rates from 19% to 15% by 2012. As a result of these changes, the Company made an adjustment to future income taxes amounting to $10.9 million in the fourth quarter of 2007. This one-time adjustment resulted in increased earnings of $10.9 million relating to the change in the future income tax liability as at December 31, 2006. An additional increase to earnings of $1.5 million was recorded relating to the change in the future income tax liability for the first nine months of 2007. Additionally, in 2007 the British Parliament enacted a 2% reduction in the corporate income tax rate effective April 1, 2008, which impacted ATCO Power's operations in the U.K. This resulted in a further increase in the Company's 2007 earnings of $4.0 million.

- ATCO Power has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that ATCO Power is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, ATCO Power is required to designate these entire contracts as derivative instruments. ATCO Power recognized a non-current derivative asset of $59.0 million on January 1, 2007; thereafter, ATCO Power will record Mark-to-Market Adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts mature in November 2014. As all but the excess volume of natural gas is committed to ATCO Power's power generation obligations, ATCO Power could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, on January 1, 2007, ATCO Power recognized a provision for a power generation revenue contract in the amount of $44.8 million, thereafter, ATCO Power will record adjustments to the power generation revenue contract liability concurrently with the Mark-to-Market Adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet. The Mark-to-Market Adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability increased earnings by $2.8 million, net of income taxes, for the three months ended December 31, 2007 and increased earnings by $2.9 million, net of income taxes, for the year ended December 31, 2007. At December 31, 2007, the natural gas purchase contracts derivative asset is $72.5 million and the power generation revenue contract liability is $54.2 million.

- In September 2007, the AUC issued a decision on ATCO Electric's general tariff application for the 2007 and 2008 test years. Included in this decision were the following:
    - rate of return on common equity of 8.75% for 2008 and 8.51% for 2007;
    - common equity ratio of 33% for transmission operations and 37% for distribution operations
    - the decision also directed ATCO Electric to change its income tax methodology for federal purposes. This change in tax methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Accordingly, in the third quarter, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $49.3 million, offset by a regulatory asset of $14.9 million which represents current income tax savings to be realized in future periods. Unrecorded future income tax liabilities increased by $34.4 million as a result of this decision. In December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers, thereby realizing $5.2 million of current income tax savings, which further reduced revenues, and reduced the future

income taxes to be refunded by $10.9 million, and will be refunding the remaining $23.5 million balance to distribution customers over a five year period commencing in 2008.

- In the fourth quarter of 2007, ATCO Gas successfully appealed previous Canada Revenue Agency ("CRA") reassessments which resulted in an $8.8 million decrease in income taxes and an increase in interest income (net of tax) of $0.7 million for an overall increase to the Company's earnings of $9.5 million. These appeals applied to the 1999 to 2006 taxation years and allow ATCO Gas to treat previously reported capital outlays as current expenditures for income tax purposes.

2006:

- Increased capital expenditures in the Utilities Business Group.
- Fluctuations in temperatures affecting ATCO Gas' operations.
- In November 2006, the AUC announced that a generic return on common equity of 8.51% would be applied on rate applications filed for 2007.
- Availability of generating plants in ATCO Power and Alberta Power (2000).
- Volatility in prices received for electricity sold to the Alberta Power Pool by ATCO Power and for electricity sold into the United Kingdom Power Exchange Market by ATCO Power.
- Lower PPA tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate that is based on long term Government of Canada bond yields plus 4.5%.
- Changes in market conditions in natural gas liquids and storage operations in ATCO Midstream.
- In 2006, the CRA issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Company has made submissions to the CRA opposing the CRA's position. The impact of the reassessment is a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings and a $28.8 million payment associated with the tax and interest assessed. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims. Due to the uncertainty as to whether the reassessment will ultimately be resolved in the Company's favour, the Company reduced earnings by $12.4 million in 2006.
- Federal and provincial governments have recently announced a number of changes to income taxes and rates. As these changes are considered to have been substantively enacted, the Company made an adjustment to income taxes amounting to $11.8 million in the second quarter of 2006, most of which relates to future income taxes. The adjustment increased 2006 earnings by $11.8 million, of which $1.9 million relates to the Utilities Business Group, $7.2 million to the Power Generation Business Group, $2.3 million to the Global Enterprises Business Group and $0.4 million to Corporate and Other.
- In June 2005, as part of their rate applications, ATCO Electric and ATCO Gas submitted a filing to the AUC that addressed certain common matters. ATCO Pipelines was also a party to this filing as the concerns were common to all three utilities. On October 11, 2006, the AUC issued a decision which

resulted in no significant impact on earnings. Among other things, the decision upheld ATCO's treatment of pension costs and approved the continued use of preferred shares. In addition, the decision approved minimal changes to head office rent expense and executive compensation.

- On November 24, 2006, the Company announced that its Board of Directors had completed its review of the strategic alternatives available for its gas gathering and processing and natural gas liquids midstream business and reached a decision to retain the business under the Company's current structure. The strategic review, commenced in May 2006, was conducted by the Board of Directors in conjunction with the Company's management and legal and financial advisors. The review involved the evaluation of a number of alternatives, including reorganization into a business trust or newly-created company or a sale to a third party.

2005:

- Volatility in prices received for electricity sold to the Alberta Power Pool and for electricity sold into the United Kingdom Power Exchange Market by ATCO Power.

- Fluctuations in temperatures affecting ATCO Gas' operations.

- In 2005, the Company received $83.1 million as its share of the partial settlement of the claim for damages related to TXU Europe's breach of its contract with BPL. An additional payment of $16.6 million was received on January 19, 2006 and a final installment of approximately $1.6 million was expected in the second quarter of 2006. The settlement is expected to generate earnings after income taxes and non-controlling interests of approximately $69 million, based on foreign currency exchange rates in effect on March 30, 2005, which will be recognized over the remaining term of the TXU Europe contract to September 30, 2010, at approximately $11 million per year. These earnings will be dependent upon the foreign currency exchange rates in effect at the time the earnings are recognized.

- In November 2005, the AUC announced a generic return on common equity of 8.93% for 2006. In January 2006, the AUC clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply to each year of the test period in the companies' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year.

- In November 2005, the AUC approved ATCO Pipelines as the party to manage the acquisition and sale of working gas at its salt cavern storage. Salt cavern working gas had historically been acquired by ATCO Gas and its predecessors.

- In May 2005, ATCO Gas filed a general rate application with the AUC for the 2005, 2006 and 2007 test years requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. In June 2005, ATCO Gas filed an application requesting interim refundable rates pending the AUC's decision on the general rate application. On August 28, 2005, ATCO Gas received a decision from the AUC approving an interim refundable rate increase, to be collected from northern customers, of $7.0 million. A decision from the AUC was received on January 27, 2006, which resulted in an earnings impact that is not materially different from the earnings based on the interim rates approved by the AUC in August 2005.

- In April 2005, ATCO Midstream leased the full storage capacity at ATCO Gas' Carbon natural gas storage facility for the 2005/2006 year resulting in higher storage revenues due to higher capacity leased and the timing and demand of storage capacity sold.

Utilities

As a result of the transfer of the retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "Direct Energy"), a subsidiary of Centrica plc in May 2004, ATCO Electric and ATCO Gas are no longer involved in arranging for the supply and sale of electricity and natural gas to customers and are therefore no longer responsible for electric energy or natural gas supply, but continue to own the assets and provide transportation and distribution services under AUC approved rates that provide for a recovery of costs of service and fair return.

Natural Gas Distribution

ATCO Gas is primarily engaged in the business of distributing natural gas throughout Alberta and in the Lloydminster area of Saskatchewan. 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 distribution 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 2,269,000. Also served are 279 smaller communities as well as rural areas having a combined population of approximately 599,000, located on or in the vicinity of ATCO Pipelines' transmission systems or the natural gas transmission pipelines of other companies. ATCO Gas provides approximately 1,002,000 customers with natural gas service, 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:

	2007	2006
Residential	916,875	886,999
Commercial	84,588	82,490
Industrial	353	358
Other	30	30
Total	1,001,846	969,877

ATCO Gas owns and operates approximately 36,500 km of distribution mains. In addition, ATCO Gas owns modern service and maintenance facilities in major centres.

Revenues and earnings of ATCO Gas are affected by temperature and consequently winter weather can have a significant impact. During a typical year, more than 90% of the earnings of ATCO Gas are generated during the months of January, February, November and December.

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

	2007	2006
	(petajoules)	
Residential	113.2	105.3
Commercial	104.2	98.6
Industrial	14.5	14.4
Other	0.6	0.4
Total	232.5	218.7

Natural Gas Supply

Prior to April 1, 2005, as directed by the AUC, ATCO Gas purchased fixed quantities of natural gas from various gas producers at market prices that were in effect at the time the quantities were purchased. Effective April 1, 2005, as directed by the AUC, ATCO Gas no longer purchases fixed quantities of natural gas related to storage purchases and operational contracts pertaining to its natural gas field storage facility at Carbon, Alberta. ATCO Gas has leased the entire storage capacity of the 43.5 petajoule Carbon facility to ATCO Midstream since April 1, 2005. For additional information related to the leasing of the Carbon natural gas storage facility to ATCO Midstream, refer to the Annual Results of Operations – Segmented Information – Utilities – Regulatory Developments – ATCO Gas section of the Company's Management's Discussion and Analysis ("MD&A"), which is available at www.sedar.com.

In 2003, ATCO Gas commenced a project to relocate natural gas meters located inside homes to the outside. Since inception of the project, the project has cost $148 million. 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 AUC 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.

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 2007, approximately 1,080 customers were being served directly by CU Water and, in addition, bulk water sales were being made to the towns of Tofield and Viking and to 14 commercial water haulers. The operations of CU Water are subject to regulation by the AUC.

Natural Gas Transmission

ATCO Pipelines is engaged in the business of transporting natural gas throughout Alberta and the operation of a salt cavern storage peaking facility.

ATCO Pipelines owns and operates extensive natural gas transmission systems. The systems consist of approximately 8,400 km of pipelines, 22 compressor sites and a salt cavern storage peaking facility. The systems have 236 producer receipt points, 78 interconnections with TransCanada Pipelines Limited, five 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:

	2007	2006
	(terajoules/day)	
Contract Demand:		
Producer	1,470	1,366
Industrial	960	966
Distribution	104	95
Affiliates	2,609	2,605
Total	5,143	5,032
IT/OR/Variable Volumes:		
Producer	187	244
Industrial	214	234
Total	401	478
Total Contract Demand and IT/OR/Variable Volumes	5,544	5,510

Electric Distribution and Transmission

ATCO Electric is engaged in the business of transmitting and distributing electric energy to 245 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 9 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:

	2007		2006	
	Millions of Kilowatt Hours	**%**	**Millions of Kilowatt Hours**	**%**
Industrial	7,026	65	6,719	65
Commercial	2,028	19	1,967	19
Residential	1,170	11	1,098	11
Rural, REAs and other	520	5	502	5
Total	10,744	100	10,286	100

The aggregate population of the areas provided with electric utility service by ATCO Electric, NUY, NLD and YECL is approximately 473,000 and service is provided to approximately 223,000 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:

	2007		2006	
	Number	%	Number	%
Industrial	11,083	5	10,894	5
Commercial	29,912	14	29,284	13
Residential	152,146	68	146,503	68
Rural, REAs and other	29,848	13	29,657	14
Total	222,989	100	216,338	100

ATCO Electric, NUY, NLD and YECL own and operate extensive electric transmission and distribution systems. The systems consist of approximately 9,300 km of main transmission lines and 61,700 km of distribution lines. In addition, ATCO Electric delivers power to and operates approximately 12,000 km of REA-owned distribution lines.

ATCO Electric, NUY, NLD and YECL own and operate 28 diesel, natural gas turbine and hydro generating plants having an aggregate nameplate capacity of 60 megawatts in Alberta and in the Yukon and Northwest Territories. The maximum peak load demand for these plants during the year ended December 31, 2007, was 31 megawatts.

In August 2006, the AUC approved the AESO application for increased transmission infrastructure in northwest Alberta. The AESO has approval to assign to the transmission facility owner, ATCO Electric, work consisting of several distinct projects that is expected to result in 725 kilometres of new transmission lines to be constructed by 2011. The first of these projects was assigned by the AESO in June 2007, with final approval received from the AUC on November 23, 2007. This first project consists of the construction of a 226 kilometre transmission line with an estimated cost of $210 million and anticipated completion by March 31, 2010. As a result of price escalation caused by the change in completion date of the remaining distinct projects (post 2010), coupled with the increasing costs of construction in Alberta, ATCO Electric is unable to estimate the cost of the entire project at this time. In addition to the increased transmission infrastructure in northwestern Alberta, ATCO Electric anticipates that an additional 180 kilometres of transmission line projects will be required in its service area over the next five years..

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. In 2004, AGP entered into an agreement with the City of Edmonton for a 10 year renewal of the franchise to November 15, 2015. 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 used in supplying natural gas to the city. The purchase price would be determined by an arbitration process according to the arbitration laws of Alberta. 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.

Franchise Renewals

ATCO Electric has four material franchises, one of which has expired and is currently being renegotiated. Of the remaining franchises, one was renewed in 2007 and expires in 2018, one expires in 2008 and the other expires in 2014.

ATCO Gas has five material franchise agreements which expire between 2012 and 2018.

The Company anticipates that all material franchise agreements currently held will be renewed.

Power 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 AUC. All owners of new and existing generating units must sell their surplus electric energy through the Alberta Power Pool.

Regulated (Alberta Power (2000))

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

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, 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 Government of 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 PPAs were based. The return on common equity rate used in its PPA tariff calculations for Alberta Power (2000) was 8.65% in 2007 and 8.75% for 2006. The rate of return on common equity for 2008 is 8.88%.

Alberta Power (2000) operated the Rainbow generating plant during 2006 and the electricity generated was sold to the Alberta Power Pool. Alberta Power (2000) had one year after the expiry of the PPA for the Rainbow generating plant (December 31, 2005) to determine whether to decommission the plant in order to fully recover plant decommissioning costs or to continue to operate the plant. In 2007, the AESO and Alberta Power (2000) executed a contract resulting in Alberta Power (2000) continuing to operate the plant and thus be responsible for future decommissioning costs. These costs are included in Alberta Power (2000)'s asset retirement obligation liability. Under the terms of the agreement, the Company makes the plant available for transmission support services and can continue to sell energy into the Alberta Power Pool.

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

Plant	**Commissioning Date**	**Type of Generating Plant**	Name Plate Capacity Rating (megawatts)	**PPA Purchaser**	**PPA Expiry Date**
Battle River					
Unit 3	1969	coal-fired steam turbine	150	ENMAX Corporation	2013
Unit 4	1975	coal-fired steam turbine	150	ENMAX Corporation	2013
Unit 5	1981	coal-fired steam turbine	370	ENMAX Corporation	2020
			670		
Sheerness (1)					
Unit 1	1986	coal-fired steam turbine	190	TransCanada Energy Ltd.	2020
Unit 2	1990	coal-fired steam turbine	190	TransCanada Energy Ltd.	2020
			380		
Rainbow..........	1968	natural gas turbine	88	Merchant	
Sturgeon..........	1957	natural gas turbine	18	Merchant	
Total			1,156		

Note:
(1) Alberta Power (2000)'s ownership of the 760 megawatt name plate capacity.

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.

Non-Regulated (ATCO Power)

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 (megawatts)	Ownership	Net Ownership (megawatts)
Canada:				
McMahon, B.C.	1993	120	50.0%	60
Primrose, Alberta	1998	85	40.0%	34
Poplar Hill, Alberta	1998	45	80.0%	36
Rainbow Lake, Alberta	1999	90	40.0%	36
Joffre, Alberta	2000	480	32.0%	154
Valleyview, Alberta	2001	45	80.0%	36
Muskeg River, Alberta	2003	170	56.0%	95
Cory, Saskatchewan	2003	260	40.0%	104
Oldman River, Alberta	2003	32	60.0%	19
Scotford, Alberta	2003	170	80.0%	136
Brighton Beach, Ontario	2004	580	40.0%	232
United Kingdom:				
Barking, London	1995	1,000	25.5%	255
Heathrow Airport	1990	14	50.0%	7
Australia:				
Osborne, South Australia	1998	180	50.0%	90
Bulwer Island, Queensland	2001	33	50.0%	17
Total		3,304		1,311

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 pursuant to an electricity purchase agreement expiring in 2014. 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 generating 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 Alberta Power Pool or to specific customers. ATCO Power owns a 40% interest in the plant, ATCO Resources owns 10% and CNRL owns 50%.

ATCO Power operates a 45 megawatt natural gas-fired generating plant at Poplar Hill near Grande Prairie, Alberta. Revenues are derived from power sold to the Alberta Power Pool and for transmission support required by the Alberta Power Pool. ATCO Power owns an 80% interest in the plant and ATCO Resources owns 20%.

ATCO Power operates a 90 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 Alberta Power Pool. ATCO Power owns a 40% interest in the plant, ATCO Resources owns 10% and Husky owns 50%.

ATCO Power, EPCOR Power Development Corporation 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 Alberta Power Pool or to specific customers. ATCO Power owns a 32% interest in the plant, ATCO Resources owns 8%, EPCOR Power Development Corporation owns 40% and NOVA owns 20%.

ATCO Power operates a 45 megawatt natural gas-fired generating plant near Valleyview, Alberta. All of the electricity produced by the plant is sold to the Alberta Power Pool. ATCO Power owns an 80% interest in the plant and ATCO Resources owns 20%. On May 10, 2007, ATCO Power announced that it will construct an additional 45 megawatt natural gas-fired unit at this plant. All of the electricity produced by the unit will be sold to the Alberta Power Pool. Construction of the unit is scheduled for completion in 2008.

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. Pursuant to the terms of the 40 year supply contract which expires at the end of 2042, 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 Alberta Power Pool. ATCO Power owns a 56% interest in the plant, 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. Pursuant to a contract expiring in 2028, Saskatchewan Power Corporation has agreed to purchase all of the electricity generated by the plant for 25 years. ATCO Power owns a 40% interest in the plant, 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 Alberta Power Pool. On July 1, 2007, the Piikani Nation of Brockett, Alberta exercised its option to purchase a 25% interest in the plant. ATCO Power owns a 60% interest in the plant and ATCO Resources owns 15%.

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 Alberta Power Pool. The 40 year contract with AOSP expires in 2043. ATCO Power owns an 80% interest in the plant and ATCO Resources owns 20%.

A partnership formed by ATCO Power and Ontario Power Generation Inc. ("OPG") owns and operates the Brighton Beach power plant, a 580 megawatt natural gas-fired combined cycle generating plant in Windsor, Ontario. Shell Energy North America (Canada) Inc. (formerly Coral Energy Canada Inc.) supplies and pays for the natural gas used at the plant and owns, markets and trades all the electricity produced under contracts expiring in 2024. ATCO Power owns a 40% interest in the plant, ATCO Resources owns 10% and OPG owns 50%.

United Kingdom

ATCO Power and Balfour Beatty 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 generating plant"). EDF Energy plc ("EDF") and SSE Energy Supply Limited ("SSE") own the remaining 49% interest in BPL. EDF and SSE have entered into long term agreements expiring in 2010 to purchase 72.5% of the electricity produced at the plant. The remaining 275 megawatts of power is being sold into the United Kingdom electricity market on a merchant basis under a two year marketing agreement expiring September 30, 2008. The majority of the 275 megawatts has been sold forward under this agreement through the end of March 2008 with smaller volumes sold forward through September 2008. The Barking generating plant is operated by ATCO Power.

ATCO Power has a 50% interest in a joint venture with a subsidiary of EDF. 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 the 180 megawatt Osborne cogeneration plant in Adelaide, 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. The Government of South Australia has guaranteed the obligations of FOT under these agreements.

ATCO Power has a 50% interest in a second 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.

ASHCOR Technologies

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

Global Enterprises

Non-Regulated Natural Gas Gathering, Processing and Storage

ATCO Midstream owns and operates non-regulated natural gas gathering and processing facilities in Alberta. ATCO Midstream provides natural gas procurement/load balancing services for other ATCO subsidiaries, management services for ATCO Gas' storage field at Carbon and markets storage services.

Natural Gas Liquids Extraction Operations

ATCO Midstream owns a 51.3% interest in the Edmonton Ethane Extraction Plant. Located in south Edmonton, the plant extracts ethane and other natural gas liquids from natural gas flowing into the Edmonton market area. Ethane and natural gas liquids are sold under long term contracts.

ATCO Midstream owns a 12.2% working interest and operates the Empress Gas Liquids Straddle Plant. Located in southern Alberta near the Saskatchewan border, the plant extracts ethane and other natural gas liquids from natural gas flowing into TransCanada Corporation's main pipeline. Ethane is sold under long term contracts, while natural gas liquids are sold under short term contracts.

ATCO Midstream's natural gas liquids extraction plants, with their respective licensed capacities, are shown below:

Facility	NGL Extracted	Licensed Capacity (mmcf/day)	Ownership	Net Ownership (mmcf/day)	Operator
Edmonton Ethane Extraction Plant	(1)	390	51.3%	200	No
Empress Gas Liquids Straddle Plant	(1)	1,100	12.2%	134	Yes
Villeneuve Ethane Extraction Plant	(2)	40	100.0%	40	Yes
Fort Saskatchewan Ethane Extraction Plant	(2)	37	100.0%	37	Yes
		1,567		411	

Notes:

(1) Ethane and a mixture of propane, butane and pentanes plus.

(2) A mixture of ethane, propane, butane and pentanes plus.

Natural Gas Gathering and Processing Operations

ATCO Midstream owns or has a joint venture interest in eleven natural gas gathering and processing facilities, nine 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's natural gas processing plants, with their respective licensed capacities, are shown below:

Facility	Licensed Capacity (mmcf/day)	Ownership	Net Ownership (mmcf/day)	Operator
Carbondale Gas Plant	55	100.0%	55	Yes
Cranberry Gas Plant	35	100.0%	35	Yes
Golden Spike Gas Plant	65	100.0%	65	Yes
Kinsella Gathering and Compression Facility	5	100.0%	5	Yes
Nottingham Gas Plant	13	7.0%	1	No
Kisbey Gas Plant	2	50.0%	1	Yes
Puskwaskau Gas Plant	21	41.0%	9	No
Watelet Gas Plant	20	100.0%	20	Yes
West Pembina Gas Plant	145	2.4%	3	Yes
Widewater Gas Plant	10	100.0%	10	Yes
	371		204	

ATCO Midstream owns and operates the Integrated Gas System west and north of Edmonton. The system comprises approximately 525 km of gathering pipelines and a compression facility, and is connected to other ATCO Midstream processing plants. The system has a total capacity of approximately 100 mmcf/day.

Natural Gas Storage Operations

ATCO Midstream manages ATCO Gas' Carbon natural gas storage facility at Carbon, Alberta. The facility is a natural gas reservoir with a storage capacity of 43.5 petajoules (approximately 40 bcf), and has a maximum injection rate of 400 TJ/day (369 mmcd/day) and a maximum withdrawal rate of 600 TJ/day (550 mmcf/day). The facility is situated at the intersection of pipelines owned by ATCO Pipelines and TransCanada Corporation. ATCO Midstream leases the facility from ATCO Gas on an annual storage year basis. Since April 1, 2005, ATCO Midstream has leased the full storage capacity of the facility.

ATCO Midstream provides storage services on a daily to annual basis to banks, financial institutions, marketing companies, pipelines, local distribution companies and producers.

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 North Warning System, Alaska Radar System and various remote sites for Northwestel Inc. in northern Canada. ATCO Frontec provides construction, site support and technical support for NATO, United Nations and the Swedish Armed Forces in Afghanistan and eastern Europe. ATCO Frontec also provides airport operation and maintenance, facilities management, bulk fuel storage and distribution and a wide variety of services and business activities in numerous locations throughout Canada. A number of the Canadian operations are conducted with a variety of aboriginal partners throughout Canada's north.

Principal Contracts

ARCTEC Alaska, a joint venture between ATCO Frontec and Arctic Slope World Services, has a contract with the United States Air Force to manage and maintain the Alaska Radar System. The contract is extendible on a year to year basis until 2014 at the option of the United States Air Force. The joint venture has managed and maintained the Alaska Radar System since 1994.

ATCO Frontec and Pan Arctic Inuit Logistics Corporation ("Pan Arctic") have a contract with the Government of Canada, until September 2009, to operate and maintain the North Warning System. The Government of Canada has an option to extend the contract until 2011. Nasittuq Corporation, a corporation jointly owned by ATCO Frontec and Pan Arctic, operates as agent for the purposes of the North Warning System contract.

In June 2007, ATCO Frontec was awarded five NATO support contracts at the Kandahar Airfield in Afghanistan for up to five years. Specific sectors of responsibility include fire and crash rescue, visiting aircraft services, roads and grounds maintenance, facility maintenance, construction, engineering, equipment and vehicle maintenance, aircraft movement control and terminal transport, accommodation services, supply operations, airfield mechanical transport, delivery of potable water, sewage management, and waste management and disposal.

ATCO Frontec has a contract with NATO to operate and maintain communications information systems in Bosnia. ATCO Frontec will support the CRISIS Network of the Multi-National Task Force North West headquartered in Banja Luka, which provides classified and non-classified communication of data between task force command and its multi-national units stationed at four remote locations throughout northwestern Bosnia. The contract was extendible on a year to year basis and was completed May 2007 at the option of NATO.

ATCO Frontec has a contract with NATO to provide facilities and service support at the Kabul Afghanistan International Airport. The contract includes information technology support, camp support services, equipment and facility maintenance and engineering services. The contract is extendible on a year to year basis until 2009 at the option of NATO.

ATCO Frontec manages, operates and maintains facilities to support NATO Flying Training in Canada ("NFTC") located at 15 Wing, Moose Jaw, Saskatchewan. NFTC trains approximately 140 pilots per year from various NATO countries. Services include facilities operation and maintenance, utilities maintenance and management, crash fire rescue services and maintenance of a 1.5 million litre above-ground fuel farm, aircraft refueling, operation and maintenance of the site vehicle refueling point, HAZMAT and environmental first response and fire suppression systems operation and maintenance. The current contract is in effect until 2020.

Technologies

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

ATCO I-Tek provides billing services, payment processing, credit, collection and call centre services to its clients. ATCO I-Tek currently provides such services to Direct Energy for its regulated retail and competitive energy supply businesses in Alberta. In addition, ATCO I-Tek also supplies distribution-related billing and customer care services to ATCO Gas and ATCO Electric. In 2007, ATCO I-Tek's call centre was named the top customer service provider in the North American energy sector by Service Quality Measurement Group Inc. for the second year in a row.

Direct Energy has entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek to provide billing and call centre services to ensure continued quality customer service. Direct Energy has the ability to terminate this contract after the fifth anniversary upon immediate payment of termination fees which decline over the remaining term of the contract. Based upon current customer counts and service levels and a 10 year contract, revenues are estimated to be between $400-$500 million over the term of the contract.

ATCO Travel

ATCO Travel is engaged in the sale of travel services to both business and consumer sectors. ATCO Travel was awarded the 2007 Association of Canadian Travel Agencies Atlas Award for Travel Agency of the Year in Alberta and the Northwest Territories. This award recognizes ATCO Travel's commitment to its customers by developing and implementing innovative solutions for their travel needs.

BUSINESS RISKS

The business risks section in the Company's MD&A is hereby incorporated by reference and is available at www.sedar.com.

GOVERNMENT REGULATION

Under Alberta legislation, owners of public, electric or gas utilities are required to obtain AUC approval prior to issuing securities, however, through AUC orders CU and CU Inc. are exempt from this requirement.

The utility operations of the Company in Alberta (ATCO Gas, ATCO Electric, ATCO Pipelines and CU Water) are subject to the jurisdiction of the AUC 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 the delivery of electric energy, natural gas and water.

The regulated operations of the Company 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.

The provincial and territorial utility boards regulate and approve customer rates based on anticipated energy deliveries 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 deliveries are based on a forecast of economic and business conditions and, in the case of natural gas distribution 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 regulator 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.

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

	Year	Date of Decision (1)	Mid-Year Rate Base ($ Millions)	Rate of Return on Common Equity (2) (%)		Common Equity Ratio (3) (%)	
ATCO Electric							
Transmission	2007	Dec. 21/07	844.2	8.51	(4)	33.0	(4)
	2008	Dec. 21/07	888.4	8.75	(4)	33.0	(4)
Distribution	2007	Dec. 21/07	772.0	8.51	(4)	37.0	(4)
	2008	Dec. 21/07	883.7	8.75	(4)	37.0	(4)
ATCO Pipelines							
North	2003	Dec. 02/03	351.8	9.50		43.5	
	2004	Dec. 02/03	355.2	9.60	(4)	43.0	(4)
South	2003	Dec. 02/03	144.8	9.50		43.5	
	2004	Dec. 02/03	147.6	9.60	(4)	43.0	(4)
ATCO Gas							
North	2005	May 15/07	508.9	9.50	(4)	38.0	(4)
	2006	May 15/07	532.8	8.93	(4)	38.0	(4)
	2007	May 15/07	558.3	8.51	(4)	38.0	(4)
South	2005	May 15/07	559.6	9.50	(4)	38.0	(4)
	2006	May 15/07	534.2	8.93	(4)	38.0	(4)
	2007	May 15/07	550.6	8.51	(4)	38.0	(4)

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) *The common equity ratio is the percentage of rate base considered to be financed by common equity.*

(4) *The rate of return on common equity and common equity ratio were determined by the AUC's generic cost of capital decision dated July 2, 2004.*

Generic Cost of Capital

The AUC approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares and establishes the capital structure for each utility. On July 2, 2004, the AUC established a standardized approach for determining the rate of return on common equity for each utility regulated by the AUC. This rate of return will be adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Government of Canada bond yields for the month of October as reported in the National Post. The generic return on equity determined on an annual basis in accordance with the generic cost of capital decision applies to each year of the test period in the utilities' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year. The rate of return was 8.93% for 2006, 8.51% for 2007 and has been set at 8.75% for 2008.

Electric Utilities Act

Transmission

Under the EUA, wholesale tariffs for transmission must be approved by the AUC. 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 Alberta Power Pool. The Alberta Power Pool then aggregates these costs and charges a common transmission rate to all who use the transmission system.

The Alberta Power Pool has developed and approved rules as mandated in the Transmission Regulation enacted by the Government of Alberta in 2004. These rules direct that new transmission projects will be assigned to the Transmission Facility Owners based on the service areas of the distribution companies they have been historically affiliated with. Ownership of facilities will change at service area boundaries except where, in the opinion of the Alberta Power Pool, only a small portion of the project is in another service area. All expansions of existing facilities will be assigned to the existing owner.

Distribution

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

Environmental Protection

The Company'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 Company'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 Company'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, the Company 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 Company'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 $32 million in 2007 and are estimated to be $38 million in 2008.

On April 26, 2007, the federal government released a plan that proposes mandatory GHG emission targets on industry. The proposed plan requires an initial reduction in 2010 of 18% from 2006 levels followed thereafter by annual reductions of an additional 2%. New facilities (2004 or later) are allowed a 3-year grace period after which they must improve emission intensity by 2% per year below the clean fuel standard. Compliance may be achieved by reduction or capture, limited investment in a technology fund, emission credit trading, purchase of offset credits, Kyoto Protocol Clean Development Mechanisms (maximum 10%) and very limited opportunity for early action credits. Specific details on the regulations have yet to be released and will be required to assess the financial impact of the federal framework. It is anticipated that the PPAs will allow the Company to recover most of the costs associated with complying with the new regulations.

On April 20, 2007, and June 27, 2007, respectively, the Government of Alberta approved Bill 3, Climate Change and Emissions Management Amendment Act and the Specified Gas Emitters Regulation Amendment that requires Alberta facilities that emit 100,000 tonnes or more of GHG to reduce facility emission intensities by 12% starting July 1, 2007. Units commissioned before January 1, 2000, or that have less than nine years of commercial operation are required to reduce their emission intensity by 2% per year starting in the fourth year of commercial operation to a maximum of 12% in the ninth year of commercial operation. Cogeneration units with emissions less than a deemed emission target based on a stand-alone natural gas combined cycle unit and conventional boiler will be eligible for credits. It is anticipated that the PPAs will allow the Company to recover most of the costs associated with complying with the new regulations.

The Alberta government implemented a mercury emission regulation in March 2006. The regulation requires coal-fired plant operators, including Alberta Power (2000), to monitor mercury emissions and capture at least 70% of the mercury in the coal starting January 1, 2011. It is anticipated that the PPAs will allow the Company to recover most of the costs associated with complying with the new regulation.

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

The authorized share capital of the Company consists of 150,000 Series Preferred Shares issuable in series, an unlimited number of Series Second Preferred Shares issuable in series and an unlimited number of Class A shares and Class B shares. At February 15, 2008, the Company had outstanding:

- no Series Preferred Shares;
- six series of Series Second Preferred Shares totaling 20,400,000 shares ($510.0 million);
- 81,555,386 Class A Shares; and
- 43,739,284 Class B Shares.

Series Preferred Shares

The Series Preferred Shares are entitled, in priority to the Series Second Preferred Shares and the Class A shares and Class B shares, to fixed cumulative preferential cash dividends and, in the event of the liquidation, dissolution or winding-up of the Company, or other distribution of assets of the Company among its shareholders for the purpose of winding up its affairs, to the amount paid up thereon and accrued and unpaid dividends and, if such action is voluntary, the premiums payable on redemption, if any.

The Series Preferred Shares are subject to redemption on 30 days' notice and are non-voting except upon the failure of the Company to pay dividends on any such shares for a period of 18 months, in which case the holders of all such shares are entitled to one vote per share and to elect at meetings of shareholders at which directors are elected just under one-half of the directors of the Company.

The provisions attaching to the Series Preferred Shares stipulate that no shares ranking junior to the Series Preferred Shares may be retired unless all dividends then payable on the Series Preferred Shares shall have been declared and paid.

Two series of Series Preferred Shares aggregating 65,000 shares have been designated and issued to date, all of which have been redeemed and cancelled.

Series Second Preferred Shares

An unlimited number of Series Second Preferred Shares are issuable in series, each series consisting of such number of shares and having such provisions attaching thereto as may be determined by the directors. The Series Second Preferred Shares as a class have, among others, provisions to the following effect:

(i) The Series Second Preferred Shares rank junior to the Series Preferred Shares but are, with respect to priority in payment of dividends and in the distribution of assets in the event of liquidation, dissolution or winding up of the Company, entitled to preference over the Class A Shares and the Class B Shares and any other shares of the Company ranking junior to the Series Second Preferred Shares. The Series Second Preferred Shares may also be given such other preference over the Class A Shares and the Class B Shares and any other junior shares as may be determined for any series authorized to be issued.

(ii) The Series Second Preferred Shares of each series rank equally with the Series Second Preferred Shares of every other series with respect to priority in payment of dividends and in the distribution of assets in the event of liquidation, dissolution or winding up of the Company.

(iii) The holders of the Series Second Preferred Shares are not entitled as such (except as provided in any series) to any voting rights nor to receive notice of or to attend shareholders' meetings unless dividends on the Series Second Preferred Shares of any series are in arrears to the extent of eight quarterly dividends or four half-yearly dividends, as the case may be, whether or not consecutive. Until all arrears of dividends have been paid, such holders will be entitled to receive notice of and to attend all shareholders' meetings at which directors are to be elected (other than separate meetings of holders of another class of shares) and to one vote in respect of each Series Second Preferred Share held.

The following Series Second Preferred Shares are currently outstanding:

	Stated Value	Redemption Dates (1)	2007	
			Shares	Amount
	(dollars)			(millions of dollars)
Cumulative Redeemable Second Preferred Shares				
5.8% Series W (2)	$25.00	See below	6,000,000	150.0
6.0% Series X (3)	$25.00	See below	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares				
4.35% Series O (4)	$25.00	December 2, 2011	1,600,000	40.0
4.35% Series T (4)	$25.00	December 2, 2011	1,600,000	40.0
4.35% Series U (4)	$25.00	December 2, 2011	800,000	20.0
4.70% Series V (4)	$25.00	October 3, 2012	4,400,000	110.0
				510.0

Notes:

(1) *The preferred shares, except for the Series W and X, are redeemable on the dates specified above at the option of the Company at the stated value per share plus accrued and unpaid dividends.*

(2) *The Series W preferred shares are redeemable commencing on March 1, 2008 at the stated value per share 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.*

(3) *The Series X preferred shares are redeemable commencing June 1, 2008 at the stated value per share 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.*

(4) *The dividends payable on the Series O, T, U and V preferred shares are fixed until the redemption dates specified above, at which time a new dividend rate may be established by negotiations between the Company and the owners of the shares.*

On May 18, 2007, the Company redeemed all of the $126.5 million of outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S at a price of $25.00 per share plus accrued and unpaid dividends per share.

Class A Shares and 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 Company on either of such classes of shares as well as the remaining property of the Company 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 Company, 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 Class A shares are entitled to exchange their shares for Class B shares of the Company if ATCO Ltd., the present controlling share owner of the Company, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares of the

Company. 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.

DIVIDENDS

Cash dividends declared during the past three years for all series and classes of preferred and common shares are as follows:

	Year Ended December 31		
	2007	2006	2005
		($ per share)	
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O (1)	1.13	1.26	1.26
Series Q (2)	0.68	1.48	1.48
Series R (2)	0.61	1.33	1.33
Series S (2)	0.77	1.65	1.65
Series T (1)	1.09	1.26	1.26
Series U (1)	1.09	1.26	1.26
Series V (3)	1.28	1.31	1.31
Series W	1.45	1.45	1.45
Series X	1.50	1.50	1.50
Class A and Class B Shares	1.25	1.40	1.10

Notes:

(1) *The dividend was reset to $1.09 (from 5.05% to 4.35%) for dividend periods commencing between December 2, 2006 and December 2, 2011.*

(2) *Redeemed May 18, 2007.*

(3) *The dividend was reset to $1.18 (from 5.25% to 4.70%) for dividend periods commencing between October 3, 2007 and October 3, 2012.*

It is the policy of the Company to pay dividends quarterly on its Class A and Class B shares. For the first quarter of 2007, the quarterly dividend payment on the Corporation's Class A and Class B shares was increased by $0.015 to $0.305 per share. For the second quarter of 2007, the quarterly dividend on the Corporation's Class A and Class B shares was increased by $0.01 to $0.315 per share. The quarterly dividend payment for the third and fourth quarters remained unchanged at $0.315 per share. The Company 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 2008, the quarterly dividend payment has been increased by $0.0175 to $0.3325 per share. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Company and other factors.

CREDIT RATINGS

The current credit ratings on the Company'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	Pfd-2 (high)	P-2 (high)
CU Inc.:		
Debentures	A (high)	A
Commercial paper	R-1 (low)	A-1 (mid)
Preferred Shares	Pfd-2 (high)	P-2 (high)

Notes:

(1) DBRS Limited ("DBRS") maintains a stable trend on the above securities.

(2) Standard and Poor's ("S&P") maintains a stable trend on the above securities.

Long Term Debt Credit Ratings

An A rating by DBRS is the third highest of ten categories. Long term debt rated A is of satisfactory credit quality. Protection of interest and principal is substantial with a higher degree of strength than that of B rated entities. A is a respectable rating. Entities in this category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher-rated securities. "High" and "low" grades may be used to indicate the relative standing of a credit within a particular rating category.

An A rating by S&P is the third highest of eleven categories. Obligations rated A by S&P are somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories, however, the obligor's capacity to meet its financial commitment on the obligations is still strong. The addition of a plus or minus sign shows relative standing within the rating categories. On October 18, 2007, Standard and Poor's announced that it had upgraded its rating on Canadian Utilities' unsecured long term debt from A- to A.

Commercial Paper Credit Ratings

An R-1 (low) rating by DBRS is the third highest of ten categories and is granted to short-term debt of satisfactory credit quality. The overall strength and outlook for key liquidity, debt, and profitability ratios is more favourable than with lower rating categories. Any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in its industry.

An A-1 (mid) rating by S&P is the second highest of eight categories in its Canadian commercial paper ratings scale and is granted where the obligor's capacity to meet its financial commitment on the obligation is strong.

Preferred Share Credit Ratings

A Pfd-2 rating by DBRS is the second highest of six categories granted by DBRS for preferred shares and is granted to companies presenting satisfactory credit quality where protection of dividends and principal is still substantial, but earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies. "High" and "low" grades may be used to indicate the relative standing of a credit within a particular rating category.

A P-2 rating by S&P is the second highest of eight categories S&P uses in its Canadian preferred share rating scale and is granted where the obligor's capacity to meet its financial commitments is considered adequate, but adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity to meet its financial commitment on the obligation. "High", "mid" and "low" grades may be used to indicate the relative standing of a credit within a particular rating category.

Credit Ratings Generally

A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

DIRECTORS AND EXECUTIVE OFFICERS

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

Name, Province or State and Country of Residence	Position	Principal Occupation	Periods Served as a Director of the Company
R.T. Booth (4) Alberta, Canada	Director	Partner, Bennett Jones LLP (barristers and solicitors)	1998 to date
W.L. Britton, Q.C. (2) Alberta, Canada	Director & Vice Chairman of the Board	Vice Chairman of the Board, Canadian Utilities Limited and ATCO Ltd.	1980 to date
L.M. Charlton (3) Alberta, Canada	Director	Corporate Director	2006 to date
D.T. Davis Alberta, Canada	Vice President, Internal Audit & Risk Management	Vice President, Internal Audit & Risk Management, Canadian Utilities Limited and ATCO Ltd.	
B.P. Drummond (2) (5) Quebec, Canada	Director	Corporate Director	1997 to date

Name, Province or State and Country of Residence	Position	Principal Occupation	Periods Served as a Director of the Company
O.G. Edmondson Alberta, Canada	Vice President, Business Development Finance	Vice President, Business Development Finance, Canadian Utilities Limited and ATCO Ltd.	
B.K. French (3) (4) Alberta, Canada	Director	President, Karusel Management Ltd. (property management and management consultants)	1981 to date
C. Gear Alberta, Canada	Assistant Corporate Secretary	Assistant Corporate Secretary, Canadian Utilities Limited and ATCO Ltd.	
I.D. Hargrave Alberta, Canada	Vice President, Project Development	Vice President, Project Development, Canadian Utilities Limited and ATCO Ltd.	
L.A. Heathcott (5) Alberta, Canada	Director	President & Chief Executive Officer, Spruce Meadows (international show jumping venue)	2000 to date
E.M. Kiefer Alberta, Canada	Vice President, Human Resources	Vice President, Human Resources, Canadian Utilities Limited and ATCO Ltd.	
S.W. Kiefer Alberta, Canada	Managing Director, Utilities & Chief Information Officer	Managing Director, Utilities & Chief Information Officer, Canadian Utilities Limited and ATCO Ltd.	
C.S. McConnell Alberta, Canada	Treasurer	Treasurer, Canadian Utilities Limited and ATCO Ltd.	
T.B. McLaren Alberta, Canada	Vice President, Special Projects	Vice President, Special Projects, Canadian Utilities Limited	
H.M. Neldner (2) (3) (4) (5) Alberta, Canada	Director	Corporate Director	1991 to date

Name, Province or State and Country of Residence	Position	Principal Occupation	Periods Served as a Director of the Company
M.R.P. Rayfield (5) Ontario, Canada	Director	Vice Chairman, Investment & Corporate Banking, BMO Capital Markets	2004 to date
M.M. Shaw Alberta, Canada	Managing Director, Global Enterprises	Managing Director, Global Enterprises, Canadian Utilities Limited and ATCO Ltd.	
J.W. Simpson (2) (3) (4) California, U.S.A.	Lead Director	Corporate Director	2004 to date
N.C. Southern Alberta, Canada	Director, President & Chief Executive Officer	President & Chief Executive Officer, Canadian Utilities Limited and ATCO Ltd.	1990 to date
R. D. Southern, C.B.E., C.C., LL.D. (6) Alberta, Canada	Director & Chairman of the Board	Chairman of the Board, Canadian Utilities Limited and ATCO Ltd.	1977 to 1979 1980 to date
P. Spruin Alberta, Canada	Corporate Secretary	Corporate Secretary, Canadian Utilities Limited and ATCO Ltd.	
R. J. Urwin (3) London, England	Director	Corporate Director	2007 to date
R.H. Walthall Alberta, Canada	Managing Director, Power Generation Group	Managing Director, Power Generation, Canadian Utilities Limited and ATCO Ltd.	
K.M. Watson Alberta, Canada	Senior Vice President & Chief Financial Officer	Senior Vice President & Chief Financial Officer, Canadian Utilities Limited and ATCO Ltd.	
S.R. Werth Alberta, Canada	Senior Vice President & Chief Administration Officer	Senior Vice President & Chief Administration Officer, Canadian Utilities Limited and ATCO Ltd.	
C.W. Wilson (3) (4) Colorado, U.S.A.	Director	Corporate Director	2000 to date

Name, Province or State and Country of Residence	Position	Principal Occupation	Periods Served as a Director of the Company
P.G. Wright Alberta, Canada	Vice President, Finance & Controller	Vice President, Finance & Controller, Canadian Utilities Limited and ATCO Ltd.	

<u>*Notes:*</u>

(1) All directors hold office until the close of the annual meeting of shareholders of the Company or until their successors are elected or appointed.

(2) Member of the Corporate Governance – Nomination, Compensation and Succession Committee.

(3) Member of the Audit Committee.

(4) Member of the Risk Review Committee.

(5) Member of the Pension Fund Committee.

(6) R.D. Southern was a director of Canadian Airlines Corporation when it filed for protection under the Companies' Creditors Arrangement Act on March 24, 2000.

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. Charlton who was Business Consultant, Investors' Petroleum Consultants Ltd. (oil and gas consulting and management company) from 2005-2006, and prior thereto was Vice President, Chief Operating Officer, Investors' Petroleum Consultants Ltd. from 1984 to 2005; Ms. C. Gear who was Deputy Company Secretary of LogicaCMG plc (global information technology company); Mr. J.W. Simpson who was Vice President, Middle East & North Africa, Business Development, Chevron Texaco Corporation from 2003 to 2004, and prior thereto was President, Chevron Canada Resources Ltd. from 1999-2003; and Dr. R.J. Urwin who was Group Chief Executive of National Grid Group plc (international gas and electric utility) from 2001 to 2006.

SHAREHOLDINGS OF DIRECTORS AND EXECUTIVE OFFICERS

At December 31, 2007, the directors and officers of the Company, as a group, beneficially owned, directly or indirectly (via corporate holdings or otherwise), or exercised control or direction over approximately 74.9% of the outstanding Class B common shares of the Company.

AUDIT COMMITTEE

Audit Committee Charter

Canadian Utilities Limited Audit Committee Mandate

Purpose

The purpose of this mandate is to establish the terms of reference of the Audit Committee (the "Committee") of the Company. The Committee is appointed by the Board of Directors (the "Board") of the Company. The Committee is responsible for contributing to the effective stewardship of the Company by assisting the Board in fulfilling its oversight of:

- the integrity of the Company's financial statements;
- the Company's compliance with applicable legal and regulatory requirements;
- the independence, qualifications and appointment of the Company's external auditor;
- the performance of the Company's internal audit function and external auditor;
- the accounting and financial reporting processes of the Company; and
- audits of the financial statements of the Company.

Composition

The Board shall elect annually from among its members an Audit Committee comprised of not less than 3 directors. Each member of the Committee must be:

- a director of the Company;
- independent (within the meaning of sections 1.4 and 1.5 of Multilateral Instrument 52-110 - Audit Committees); and
- financially literate (within the meaning of section 1.6 of Multilateral Instrument 52-110 - Audit Committees).

In order to be considered to be an independent director for the purposes of membership on the Committee, a director must have been determined by the Board to be independent in accordance with all applicable regulatory requirements.

The Board will appoint one member of the Committee as Chairman. Any member of the Committee may be removed or replaced at any time by the Board, and a member shall cease to be a member of the Committee upon ceasing to be independent.

Meetings

The Committee shall meet at least four times per year and whenever deemed necessary by the Chairman of the Committee or at the request of a Committee member or the Company's external or internal auditor. The Committee Chairman shall prepare and/or approve an agenda in advance of each meeting. Reasonable notification of meetings, which may be held in person, by telephone or other communication device, shall be sent to the members of the Committee, the external auditor and any additional attendees as determined by the Chairman. The external auditor has the right to appear before and be heard at any meeting of the Committee. Upon the request of the external auditor, the Chairman of the Committee shall convene a meeting of the Committee to consider any matters which the auditor believes should be brought to the attention of the directors or shareholders of the Company. Meetings will be scheduled to permit timely review of Committee materials. A majority of the Committee will constitute a quorum. Minutes of each meeting will be prepared by the person designated by the Committee to act as secretary and will be kept by the Corporate Secretarial Department.

Reporting

The Committee shall report to the Board of the Company on such matters and questions relating to the financial position of the Company as the Board may from time to time refer to the Committee. A summary of all meetings will be provided to the Board by the Committee Chairman. Supporting schedules and information reviewed by the Committee will be available for examination by any director upon request. The external auditor and the Vice President, Internal Audit & Risk Management shall report directly to the Committee. The Committee is expected to maintain free and open communication with the Company's external auditor, internal auditor and management. This communication shall include private sessions, at least annually, with each of these parties.

Responsibilities and Authority

The Committee relies on the expertise and knowledge of management and the internal and external auditors in carrying out its oversight responsibilities. Management of the Company is responsible for determining that the Company's financial statements are complete, accurate and in accordance with generally accepted accounting principles. The external auditor is responsible for auditing the Company's financial statements.

The Committee shall have the power to conduct or authorize investigations into any matters within the Committee's scope of responsibilities. The Committee shall have the authority to retain independent counsel, accountants or other outside advisors as it determines necessary to permit it to carry out its duties, to set and pay the compensation for any advisors employed by the Committee, and to communicate directly with the internal and external auditors.

The Committee shall:

- Recommend to the Board:

  (a) The external auditor to be nominated for the purpose of preparing or issuing an audit report or performing other audit, review or attestation services for the Company;
  (b) The compensation of the external auditor; and
  (c) The approval of the Company's annual financial statements, AIF and MD&A.

- Be directly responsible for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attestation services for the Company, including the resolution of disagreements between management and the external auditors regarding financial reporting.

- Pre-approve all non-audit services to be provided to the Company or its subsidiaries by the external auditor of the Company or its subsidiaries. The Committee may delegate to one or more of its members the authority to grant pre-approvals provided that any pre-approvals so granted are presented in writing to the Committee at the next regularly scheduled meeting. The Committee will ensure that relevant policies and procedures are in place to manage this process and comply with all applicable regulatory requirements.

- Review the Company's annual and interim financial statements, AIF, MD&A and annual and interim earnings press releases before this information is publicly disclosed.

- As delegated by the Board, review and approve the interim financial statements, MD&A and earnings press releases before this information is publicly disclosed.

- Be satisfied that adequate procedures are in place for the review of the Company's disclosure of financial information extracted or derived from the Company's financial statements, and periodically assess the adequacy of such procedures. This would include an annual review of the Company's Disclosure Policy.

- Establish procedures for:

  (a) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, auditing matters, fraud or theft; and
  (b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters, fraud or theft.

- Ensure the Company has implemented appropriate systems of internal control over financial reporting and that these systems are operating effectively;

- Ensure the internal audit function has been effectively carried out and the internal auditors have adequate resources;

- Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Company;

- Review and reassess annually the adequacy of this mandate and recommend any proposed changes to the Board for approval.

The members of the Committee, for the purpose of performing their duties, have the right to inspect all the books and records of the Company and its subsidiary entities and to discuss such books and records in any manner relating to the financial position of the Company and its subsidiary entities with the officers, employees and external auditors of the Company and its subsidiary entities.

The Committee will inquire into any other matters referred to it by the Board.

Composition of the Audit Committee

The following are members of the Company's Audit Committee. All members are independent and financially literate:

- L.M. Charlton
- B.K. French
- H.M. Neldner
- J.W. Simpson
- R.J. Urwin
- C.W. Wilson

Relevant Education and Experience

L.M. Charlton	Ms. Charlton has a Bachelor of Commerce degree. Ms. Charlton has held positions of increasing financial responsibility ranging from Financial Analyst to Chief Financial Officer during her 22 year career at Investors' Petroleum Consultants Ltd. In April 2006, Ms. Charlton completed the Institute of Corporate Directors "Financial Literacy for Directors and Executives Course".
B.K. French	Mr. French has a Bachelor of Commerce with an Accounting and Finance Major and is a Chartered Accountant. Mr. French was engaged in public practice for 25 years.
H.M. Neldner	Mr. Neldner has a Bachelor of Commerce (Finance). Mr. Neldner held various senior management positions in accounting and finance including General Accountant, Comptroller, Vice President Finance and President & CEO with Alberta Government Telephones and Telus Corporation.
J.W. Simpson	Mr. Simpson graduated from an Executive Program at M.I.T's Sloan School of Business. During Mr. Simpson's career at Chevron Corporation various financial positions reported to him. In his capacity as General Manager the accounting department reported to him and as President of Chevron Canada the Vice President Finance directly reported to Mr. Simpson. In addition, Mr. Simpson was Chairman of the Internal Audit Committee of Chevron Canada.
R.J. Urwin	Dr. Urwin was the Chief Executive Officer of the National Grid Group plc's transmission business from 1995 until his retirement in 2006. National Grid plc is a public international gas and electric utility with operations in the United States and is subject to Sarbanes-Oxley requirements. Dr. Urwin has been a member of the Audit Committees of a series of public UK companies and is currently on the Audit Committee of Utilico Investment Trust plc.
C.W. Wilson	Mr. Wilson has an understanding of the accounting principles of the Company. In addition, Mr. Wilson previously supervised a CFO directly for a seven year period as President & CEO of Shell Canada Ltd.

Reliance on Certain Exemptions

The Company did not rely on any exemptions from the Audit Committee requirements of Canadian securities legislation.

Audit Committee Oversight

Since January 1, 2007, all recommendations of the Audit Committee to nominate or compensate an external auditor were adopted by the Board of Directors.

Pre-Approval Policies and Procedures

The Audit Committee and the Board of Directors of the Company have adopted a policy for approval of external auditor services. The policy prohibits the external auditor from providing specified services to the Company and its subsidiaries.

The engagement of the external auditor for a range of services defined in the policy has been pre-approved by the Audit Committee. If an engagement of the external auditor is contemplated for a particular service that is neither prohibited nor covered under the range of pre-approved services, such engagement must be pre-approved. The Audit Committee has delegated the authority to grant such pre-approval to the Chairman of the Audit Committee.

Services provided by the external auditor are subject to an engagement letter. The policy mandates that the Audit Committee receive regular reports of all new pre-approved engagements of the external auditor.

External Auditor Service Fees

The aggregate fees incurred by the Company and its subsidiaries for professional services provided by PricewaterhouseCoopers LLP for each of the past two years were as follows:

	2007	2006
	($Millions)	
Audit (1)	1.6	1.4
Audit Related (2)	0.1	0.1
Tax (3)	0.2	0.3
Other	0.1	-
Total	2.0	1.8

Notes:

(1) Audit fees include the aggregate professional fees paid to the external auditor for the audit of the annual consolidated financial statements and other regulatory audits and filings.

(2) Audit-related fees include the aggregate fees paid to the external auditor for services related to special purpose audits and audit services including consultations regarding financial reporting and accounting standards.

(3) Tax fees include the aggregate fees paid to the external auditor for tax compliance, tax advice, tax planning and advisory services relating to the preparation of corporate tax, capital tax and sales tax returns.

MARKETS FOR THE SECURITIES OF THE COMPANY

The Company's Class A shares, Class B shares and Cumulative Redeemable Second Preferred Shares, Series 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.

The following table sets forth the high and low prices and the volume of shares traded on the Toronto Stock Exchange during 2007 for the Company's listed shares.

	Class A Shares			Class B Shares		
	High $	**Low $**	**Volume**	**High $**	**Low $**	**Volume**
January	48.94	42.02	2,084,959	48.65	42.50	42,398
February	44.80	42.19	3,538,543	44.74	42.00	59,302
March	44.60	41.83	2,060,739	44.40	42.15	66,703
April	46.64	42.26	1,163,846	46.25	42.51	134,792
May	50.39	44.98	4,226,220	49.95	45.20	149,571
June	50.00	45.19	4,589,272	49.90	45.35	27,873
July	48.96	45.34	1,735,731	48.54	45.50	22,064
August	48.85	42.78	2,494,559	48.50	43.00	32,822
September	49.33	46.40	1,342,558	49.30	46.15	16,495
October	54.36	47.44	2,113,367	53.49	47.02	61,338
November	55.00	48.50	3,819,346	54.00	49.00	32,610
December	51.25	44.86	1,487,735	50.55	44.85	40,538

	Cumulative Redeemable Second Preferred Shares					
	Series X			Series W		
	High $	**Low $**	**Volume**	**High $**	**Low $**	**Volume**
January	27.49	27.01	29,150	27.22	26.89	35,102
February	27.06	26.31	37,029	26.99	26.00	51,514
March	27.38	26.56	62,391	26.83	26.14	74,209
April	27.43	26.80	125,768	26.60	26.15	53,080
May	27.20	25.50	569,576	26.54	25.55	520,022
June	25.98	25.15	77,420	26.09	25.01	66,281
July	25.99	25.47	85,402	26.15	24.79	28,941
August	26.00	25.45	35,374	25.71	24.76	72,210
September	26.37	25.83	45,510	26.21	25.31	166,197
October	26.40	26.00	69,400	25.99	25.50	48,509
November	26.20	25.75	116,980	26.34	25.61	81,628
December	27.00	25.30	22,048	26.00	25.00	35,115

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Class A Shares and Class B Shares is CIBC Mellon Trust Company at its principal offices in Calgary, Vancouver, Toronto and Montreal. The transfer agent and registrar for the Cumulative Redeemable Second Preferred Shares, Series W and X preferred shares is CIBC Mellon Trust Company at its principal offices in Calgary, Toronto and Montreal. The transfer agent and registrar for the Perpetual Cumulative Second Preferred Shares Series O, T, U and V is the Company at its principal office in Calgary. The trustee and transfer agent for the debentures of the Company is CIBC Mellon Trust Company at its principal offices in Calgary and Toronto.

EXPERTS

PricewaterhouseCoopers LLP has prepared the auditor's report with respect to the Company's annual financial statements. PricewaterhouseCoopers LLP is independent in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

EMPLOYEE RELATIONS

At December 31, 2007, the Company and its joint ventures had the following number of employees:

	Number
Utilities	3,789
Global Enterprises	2,057
Power Generation	541
Other	114
Sub Total	6,501
Joint Ventures – Global Enterprises	560
Joint Ventures – Power Generation	202
Sub Total	762
Total	7,263

Approximately 3,710 employees are members of four employee associations and nine unions and are covered by 18 collective agreements. Four of these agreements have expired and are under re-negotiation and the remaining Fourteen agreements expire over the period April 30, 2008 to March 31, 2010.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans, is contained in the Company's Management Proxy Circular dated March 1, 2007. Additional financial information is provided in the Company's comparative financial statements and MD&A for the financial year ended December 31, 2007.

Information relating to ATCO Ltd. or CU Inc. may be obtained upon request from the Corporate Secretary of each 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 Company's website: www.canadian-utilities.com. Additional information relating to the Company may be found on SEDAR at www.sedar.com.

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED
An ATCO Company

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2007

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
111 5 Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

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, 2007 and 2006 and the consolidated statements of earnings and retained earnings, cash flows and comprehensive income for each of the years in the two year period ended December 31, 2007. These consolidated financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2007 and 2006 and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta

February 19, 2008

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

	Note	Three Months Ended December 31 2007	Three Months Ended December 31 2006	Year Ended December 31 2007	Year Ended December 31 2006
		(Unaudited)			
Revenues	3	**$ 657.1**	$ 671.1	**$2,404.9**	$2,430.4
Costs and expenses					
Natural gas supply		**24.8**	10.2	**42.1**	36.4
Purchased power		**13.6**	12.5	**49.9**	46.1
Operation and maintenance		**251.4**	243.5	**941.6**	950.3
Selling and administrative		**77.1**	74.9	**216.8**	207.5
Depreciation and amortization		**99.0**	95.6	**351.5**	348.5
Interest	6, 12	**55.0**	54.6	**217.4**	222.9
Franchise fees		**37.4**	42.4	**151.2**	150.4
		558.3	533.7	**1,970.5**	1,962.1
		98.8	137.4	**434.4**	468.3
Interest and other income	5	**21.3**	18.9	**64.3**	58.5
Earnings before income taxes		**120.1**	156.3	**498.7**	526.8
Income taxes	3, 6	**13.1**	47.4	**77.7**	167.1
		107.0	108.9	**421.0**	359.7
Dividends on equity preferred shares		**8.3**	8.9	**34.3**	35.8
Earnings attributable to Class A and Class B shares		**98.7**	100.0	**386.7**	323.9
Retained earnings at beginning of period as restated	7	**1,984.1**	1,741.1	**1,813.3**	1,721.9
		2,082.8	1,841.1	**2,200.0**	2,045.8
Dividends on Class A and Class B shares		**39.6**	36.3	**156.8**	176.7
Purchase of Class A shares and other direct charges to retained earnings	8	**7.2**	0.4	**7.2**	64.7
Retained earnings at end of period		**$2,036.0**	$1,804.4	**$2,036.0**	$1,804.4
Earnings per Class A and Class B share	15	**$ 0.78**	$ 0.80	**$ 3.08**	$ 2.57
Diluted earnings per Class A and Class B share	15	**$ 0.78**	$ 0.80	**$ 3.07**	$ 2.56
Dividends paid per Class A and Class B share	15	**$ 0.315**	$ 0.29	**$ 1.25**	$ 1.40

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

	Note	December 31 2007	2006
ASSETS			
Current assets			
Cash and short term investments	4, 18	**$ 747.2**	$ 798.8
Accounts receivable		**373.9**	362.3
Inventories		**101.8**	96.5
Regulatory assets	2	**10.2**	13.3
Derivative assets	21	**0.8**	-
Prepaid expenses		**29.8**	23.6
		1,263.7	1,294.5
Property, plant and equipment	9	**5,678.5**	5,426.1
Regulatory assets	2	**75.6**	43.2
Derivative assets	21	**73.3**	-
Other assets	10	**194.3**	229.7
		$7,285.4	$6,993.5
LIABILITIES AND SHARE OWNERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		**$ 375.0**	$ 338.8
Income taxes payable	3, 6	**1.2**	22.7
Future income taxes	6	**1.7**	0.3
Regulatory liabilities	2	**-**	0.5
Derivative liabilities	21	**2.6**	-
Non-recourse long term debt due within one year	12	**65.4**	59.3
		445.9	421.6
Future income taxes	3, 6	**153.8**	194.7
Regulatory liabilities	2	**146.5**	148.8
Derivative liabilities	21	**3.3**	-
Deferred credits	13	**307.9**	229.0
Long term debt	12	**2,603.2**	2,411.5
Non-recourse long term debt	12	**478.1**	626.7
Equity preferred shares	14	**625.0**	636.5
Class A and Class B share owners' equity			
Class A and Class B shares	15	**516.9**	516.0
Contributed surplus	16	**1.9**	1.2
Retained earnings		**2,036.0**	1,804.4
Accumulated other comprehensive income	22	**(33.1)**	3.1
Retained earnings and accumulated other comprehensive income		**2,002.9**	1,807.5
		2,521.7	2,324.7
		$7,285.4	$6,993.5

[Original signed by N.C. Southern]

DIRECTOR

[Original signed by J.W. Simpson]

DIRECTOR

CU

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

	Note	Three Months Ended December 31 2007	2006	Year Ended December 31 2007	2006
		(Unaudited)			
Operating activities					
Earnings attributable to Class A and Class B shares		**$ 98.7**	$ 100.0	**$ 386.7**	$ 323.9
Adjustments for:					
Depreciation and amortization		**99.0**	95.6	**351.5**	348.5
Future income taxes	3	**(19.5)**	11.3	**(15.7)**	(1.6)
Deferred availability incentives		**4.5**	(41.0)	**2.2**	(20.2)
TXU Europe settlement - net of income taxes	4	**(2.5)**	(3.3)	**(11.1)**	(1.6)
Other		**(0.2)**	5.8	**12.3**	8.5
Funds generated by operations		**180.0**	168.4	**725.9**	657.5
Changes in non-cash working capital	17	**(52.9)**	(48.5)	**(19.0)**	(39.6)
Cash flow from operations		**127.1**	119.9	**706.9**	617.9
Investing activities					
Purchase of property, plant and equipment		**(212.6)**	(184.0)	**(700.8)**	(567.7)
Costs on disposal of property, plant and equipment		**(14.7)**	(4.3)	**(16.2)**	(10.4)
Contributions by utility customers for extensions to plant		**25.8**	20.1	**91.2**	81.3
Non-current deferred electricity costs		**(4.5)**	(8.7)	**(9.6)**	4.5
Changes in non-cash working capital	17	**5.2**	15.4	**12.3**	(18.3)
Income tax reassessment	6	**-**	-	**-**	(12.8)
Other		**(1.1)**	0.9	**(19.0)**	(4.1)
		(201.9)	(160.6)	**(642.1)**	(527.5)
Financing activities					
Issue of long term debt		**255.0**	320.0	**255.0**	355.5
Repayment of long term debt		**(50.0)**	(175.0)	**(50.0)**	(175.0)
Repayment of non-recourse long term debt	4	**(12.3)**	(12.6)	**(122.8)**	(64.6)
Issue of equity preferred shares by subsidiary	14	**-**	-	**115.0**	-
Redemption of equity preferred shares	14	**-**	-	**(126.5)**	-
Net issue (purchase) of Class A shares		**(7.7)**	1.9	**(6.4)**	(67.5)
Dividends paid to Class A and Class B share owners		**(39.6)**	(36.3)	**(156.8)**	(176.7)
Changes in non-cash working capital	17	**-**	(0.1)	**-**	(0.1)
Other		**(3.6)**	(2.6)	**(6.3)**	(3.9)
		141.8	95.3	**(98.8)**	(132.3)
Foreign currency translation		**(2.7)**	11.6	**(17.6)**	16.3
Cash position					
Increase (decrease)		**64.3**	66.2	**(51.6)**	(25.6)
Beginning of period		**682.9**	732.6	**798.8**	824.4
End of period		**$ 747.2**	$ 798.8	**$ 747.2**	$ 798.8

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(Millions of Canadian Dollars)

		Three Months Ended December 31		Year Ended December 31	
	Note	**2007**	2006	**2007**	2006
		(Unaudited)			
Earnings attributable to Class A and Class B shares		**$98.7**	$100.0	**$386.7**	$323.9
Other comprehensive income, net of income taxes:					
Cash flow hedges	22	**0.4**	-	**2.7**	-
Foreign currency translation adjustment	22	**(7.2)**	18.1	**(31.6)**	21.3
		(6.8)	18.1	**(28.9)**	21.3
Comprehensive income		**$91.9**	$118.1	**$357.8**	$345.2

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2007

(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 (the "Corporation"). Principal operations are Utilities (ATCO Electric, ATCO Gas, ATCO Pipelines), Power Generation (ATCO Power, Alberta Power (2000)) and Global Enterprises (ATCO Midstream, ATCO Frontec, ATCO I-Tek). Significant joint venture investments consist principally of power generation plants; a substantial portion of Power Generation's operations are conducted through joint ventures.

Effective January 1, 2007, the Corporation adopted the Canadian Institute of Chartered Accountants ("CICA") recommendations pertaining to financial instruments, which establish standards for the recognition, measurement, disclosure and presentation of financial assets, financial liabilities and non-financial derivatives. These recommendations require that fair value be used to measure financial assets that are held for trading or available for sale, financial liabilities that are held for trading and all derivative financial instruments. Other financial assets, such as loans and receivables and investments that are held to maturity, and other financial liabilities are measured at their amortized cost. This change in accounting had the following effect on the consolidated financial statements for the three months and year ended December 31, 2007:

(a) Recognition of interest rate swaps, foreign currency forward contracts and certain natural gas purchase contracts as derivative assets and liabilities in the consolidated financial statements (see Note 21).
(b) Recognition of the fair value of a power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (see Note 21).
(c) Recognition of a mark-to-market adjustment for the change in fair value of the natural gas purchase contracts derivative asset and recognition of an adjustment to the associated power generation revenue contract liability (see Note 5).
(d) Restatement of opening retained earnings at January 1, 2007 to recognize the prior years' earnings effect of the natural gas purchase contracts derivative asset and the associated power generation revenue contract liability, as well as the prior years' earnings effect of accounting for certain financial assets and financial liabilities at amortized cost using the effective interest method (see Note 7).
(e) Reclassification of deferred financing charges from other assets to long term debt and non-recourse long term debt (see Note 12).

Effective January 1, 2007, the Corporation adopted the CICA recommendations pertaining to hedges, which establish standards for the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The purpose of hedge accounting is to ensure that gains, losses, revenues and expenses from effective hedging relationships are recorded in earnings in the same period. This change in accounting had no effect on the consolidated financial statements for the three months and year ended December 31, 2007.

Effective January 1, 2007, the Corporation adopted the CICA recommendations regarding the reporting and disclosure of comprehensive income. Comprehensive income consists of changes in the equity of the Corporation from sources other than the Corporation's share owners, and includes earnings of the Corporation, the foreign currency translation adjustment relating to self-sustaining foreign operations and unrealized gains and losses on changes in fair values of available-for-sale assets and effective cash flow hedging instruments. Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income but are excluded from earnings of the period. Comprehensive income is disclosed in a separate statement in the consolidated financial statements.

1. Summary of significant accounting policies (continued)

Effective January 1, 2007, the Corporation adopted the CICA recommendations regarding the presentation of equity and changes in equity. These recommendations require separate presentation of the components of equity, including retained earnings, accumulated other comprehensive income, contributed surplus, share capital and reserves, and the changes therein. As a result of this change in accounting, the Corporation has included a reconciliation of accumulated other comprehensive income in the notes to the consolidated financial statements (see Note 22). In accordance with the recommendations, comparative figures have been adjusted to incorporate the foreign currency translation adjustment into accumulated other comprehensive income.

Effective January 1, 2007, the Corporation adopted the CICA recommendations that prescribe the criteria for changing accounting policies, together with the accounting treatment and disclosure of changes in accounting policies, changes in accounting estimates and corrections of errors. Adoption of these recommendations had no effect on the consolidated financial statements for the three months and year ended December 31, 2007, except for the disclosure of accounting changes that have been issued by the CICA but have not yet been adopted by the Corporation because they are not effective until a future date (see Future Accounting Changes below).

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

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd. and the Battle River and Sheerness generating plants of Alberta Power (2000), 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". Accounting for rate regulated operations is described in Note 2.

Use of Estimates

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

Revenue Recognition

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

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

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

Revenues from ATCO Pipelines' regulated transmission of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

1. Summary of significant accounting policies (continued)

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

Revenues from generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. Incentives and penalties associated with Alberta Power (2000)'s Power Purchase Arrangements ("PPA") are recognized as described under the accounting policy for deferred availability incentives.

Revenues from ATCO Midstream's natural gas storage and processing capacity are recognized on the basis of contractual arrangements, and revenues from the sale of natural gas liquids 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 for regulated operations, which consists of natural gas volumes purchased for sales to customers, is based on actual costs incurred.

Natural gas supply expense for ATCO Midstream, which consists of natural gas volumes purchased for natural gas liquids extraction and sales to third parties, is based on actual costs incurred.

Purchased Power

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

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.

Cash and Short Term Investments

Short term investments consist of certificates of deposit and bankers' acceptances with maturities generally of 90 days or less at purchase.

Inventories

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

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

Property, Plant and Equipment

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

Regulated operations include in property, plant and equipment an allowance for funds used during construction at rates approved by the Alberta Utilities Commission ("AUC") for debt and equity capital. 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, excluding Alberta Power (2000)'s generating plants, are approved by the AUC and include a provision for future removal costs and site restoration costs (see the accounting policy for asset retirement obligations below). On retirement of these depreciable regulated assets, the accumulated depreciation is charged with the cost of the retired unit, net disposal costs and site restoration costs.

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset's carrying value exceeds the total cash flows expected from its use and eventual disposition. The impairment loss is then calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques.

Deferred Financing Charges

Issue costs of long term debt are amortized over the life of the debt using the effective interest method. Issue costs of preferred shares relating to regulated operations are amortized over the expected life of the issue and issue costs of preferred shares relating to other subsidiaries are charged to retained earnings. Unamortized premiums and issue costs of redeemed long term debt and preferred shares relating to regulated operations are amortized over the life of the issue funding the redemption. The Corporation's deferred financing charges pertaining to long term debt have been reclassified from other assets to long term debt and non-recourse long term debt in accordance with the CICA recommendations for financial instruments (see Note 12).

Deferred Availability Incentives

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

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

Asset Retirement Obligations

Asset retirement obligations are legal obligations associated with the retirement of tangible long lived assets. To the extent that they can be quantified, these obligations are measured and recognized at fair value, which is determined using present value techniques.

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

An asset retirement obligation is recorded as a liability in deferred credits, with a corresponding increase to property, plant and equipment. The liability is accreted over the estimated time period until settlement of the obligation, with the accretion expense included in depreciation and amortization. The asset is depreciated over its estimated useful life.

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

Long Term Debt Due Within One Year

When the Corporation intends to refinance long term debt due within one year on a long term basis and there is a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity exists under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year is classified as long term.

Derivative Financial Instruments

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

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

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

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

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

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

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

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

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

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:

(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,

(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

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

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

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

Employee Future Benefits

The Corporation 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.

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

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

1. Summary of significant accounting policies (continued)

Stock Based Compensation Plans

The Corporation expenses stock options granted on and after January 1, 2002; no compensation expense is recorded for stock options granted prior to January 1, 2002 as permitted by GAAP. The Corporation determines the fair value of the options on the date of grant using an option pricing model and recognizes the fair value over the vesting period of the options granted as compensation expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

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

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 accumulated other comprehensive income in share owners' equity.

Monetary assets and liabilities of integrated foreign operations, as well as non-monetary assets carried at market value, are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date. Other non-monetary assets and non-monetary liabilities are translated at rates of exchange in effect when the assets were acquired or liabilities incurred. Revenues and expenses are translated at the average monthly rates of exchange during the year; depreciation and amortization are translated at rates of exchange consistent with the assets to which they relate. Gains or losses on translation of integrated foreign operations are recognized in earnings.

Transactions undertaken by Canadian operations that are denominated in foreign currencies are translated into Canadian dollars at the rate of exchange in effect at the transaction date. Monetary items and non-monetary items that are carried at market value arising from a transaction denominated in a foreign currency are adjusted to reflect the rate of exchange in effect at the balance sheet date. Gains or losses on translation of such monetary and non-monetary items are recognized in earnings.

Future Accounting Changes

The CICA has issued new accounting recommendations for capital disclosures which require disclosure of both qualitative and quantitative information that enables users of financial statements to evaluate the Corporation's objectives, policies and processes for managing capital. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has issued new accounting recommendations for disclosure and presentation of financial instruments which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks arising from financial instruments to which the Corporation is exposed. These recommendations are effective for the Corporation beginning January 1, 2008.

The CICA has issued new accounting recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any writedown to net realizable value, and on the cost formulas that are used to assign costs to inventories. The adoption of these recommendations is not expected to have a material impact on the earnings or assets of the Corporation. These recommendations are effective for the Corporation beginning January 1, 2008.

1. Summary of significant accounting policies (continued)

The CICA has removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. The Corporation is evaluating the possibility of using standards issued by the Financial Accounting Standards Board in the United States that allow for the recognition and measurement of rate regulated assets and liabilities as another source of Canadian GAAP. The CICA has also issued new recommendations that will require the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers. These recommendations are effective for the Corporation beginning January 1, 2009, and will be applied prospectively. The amount of unrecorded future income tax liabilities of the regulated operations at December 31, 2007 is $159.4 million.

In 2006, the CICA announced that accounting standards in Canada are to converge with International Financial Reporting Standards ("IFRS"). The Corporation will need to begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to GAAP, but there could be significant differences on recognition, measurement and disclosures that will need to be addressed. The Corporation is currently assessing the impact of these standards on its financial statements.

2. Accounting for rate regulated operations

Nature and economic effects of rate regulation

ATCO Electric, ATCO Gas and ATCO Pipelines (the "utilities") are regulated primarily by the AUC, which, effective January 1, 2008, succeeded the Alberta Energy and Utilities Board as regulator for the utilities industry. The AUC administers acts and regulations covering such matters as rates, financing, accounting, construction, operation and service area.

The Battle River and Sheerness generating plants of Alberta Power (2000) were regulated by the AUC until December 31, 2000 but are now governed by legislatively mandated PPA's that were approved by the AUC. These plants are included in regulated operations primarily because the PPA's are designed to allow the owners of generating plants constructed before January 1, 1996 to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPA's. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPA's expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to operate the plant and be responsible for the decommissioning costs. For PPA's expiring after 2018 decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

The utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment, less accumulated depreciation, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base.

2. Accounting for rate regulated operations (continued)

The AUC approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility's debt and preferred shares and establishes the capital structure for each utility. On July 2, 2004, the AUC established a standardized approach for determining the rate of return on common equity for each utility regulated by the AUC. This rate of return will be adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Government of Canada bond yields for the month of October as reported in the National Post. The generic return on equity determined on an annual basis in accordance with the generic cost of capital decision applies to each year of the test period in the utilities' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year. The rate of return was 8.93% for 2006, 8.51% for 2007 and has been set at 8.75% for 2008.

Under the cost of service methodology, the utilities seek approval for their revenue requirement either through submission of general rate applications to the AUC or a negotiated settlement process with interested parties. In the latter case, the AUC monitors the negotiated settlement process and any agreement that is reached is subject to AUC approval. The AUC may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination.

Financial statement effects of rate regulation

Certain items in these consolidated financial statements are accounted for differently than they would be in the absence of rate regulation. CICA recommendations do not require that assets and liabilities arising from rate regulation be recognized and measured in accordance with the primary sources of GAAP.

Where regulatory decisions dictate, the utilities defer certain costs or revenues as assets or liabilities on the balance sheet and record them as expenses or revenues in the earnings statement as they collect or refund amounts through future customer rates. Any adjustments to these deferred amounts are recognized in earnings in the period that the AUC renders a decision concerning these adjustments.

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

2. Accounting for rate regulated operations (continued)

The regulatory assets and liabilities comprise the following:

	2007	2006
Regulatory assets – current:		
Deferred electricity costs	$ 1.5	$ 1.7
Current income tax savings associated with future income tax refund to customers	2.0	-
Other regulatory assets [1]	6.7	11.6
	$ 10.2	$ 13.3
Regulatory assets – non-current:		
Regulatory other post employment benefits asset (Note 20)	$ 32.3	$ 27.6
Deferred electricity costs	17.4	7.1
Current income tax savings associated with future income tax refund to customers	7.0	-
Deferred hearing costs [1]	4.0	1.4
Reserves for injuries and damages	1.5	2.0
Other regulatory assets [1]	13.4	5.1
	$ 75.6	$ 43.2
Regulatory liabilities – current:		
Other regulatory liabilities [1]	$ -	$ 0.5
Regulatory liabilities – non-current:		
Regulatory pension liability (Note 20)	$110.0	$118.7
Deferred royalty credits	23.1	19.7
Deferred electricity cost recoveries	7.0	6.2
Deferred hearing costs [1]	-	0.4
Reserves for injuries and damages	2.1	2.8
Other regulatory liabilities [1]	4.3	1.0
	$146.5	$148.8

(1) Amortization of certain regulatory assets and liabilities, which was recorded in depreciation and amortization, amounted to $7.7 million (2006 – $14.7 million).

Employee future benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit plans. The regulatory asset (liability) reflects an AUC decision, effective January 1, 2000, to record costs of employee future benefits in the utilities when paid rather than accrued. The variances between the amounts paid and accrued for each of the defined benefit pension plans and the other post employment benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will be deferred until the plans are paid, settled or terminated.

GAAP requires that the variances between the amounts accrued and paid be recognized as an expense or reduction in expense in the period in which they are accrued. Consequently, defined benefit pension plan cost in 2007 would have been $7.8 million higher (2006 – $19.5 million higher), and other post employment benefit plan cost in 2007 would have been $2.9 million higher (2006 – $3.5 million higher), in the absence of rate regulation.

Upon the adoption of the current accounting standard in 2000, the utilities had recorded deferred pension assets of $23.0 million. The utilities have been earning an AUC approved rate of return on these assets through customer rates as the assets form part of the utilities' AUC approved rate base. In the absence of rate regulation, the utilities would not be able to earn a return on these assets. Consequently, revenues in 2007 would have been $1.6 million lower (2006 – $1.7 million lower). On October 11, 2006, the AUC issued a decision that approved recovery of these assets for a nine-year period commencing January 1, 2005 and permitted the utilities to continue to earn an AUC approved rate of return on the unrecovered portion of these assets over the recovery period. In 2007, the utilities amortized $2.6 million (2006 – $5.1 million) of the deferred pension asset.

2. Accounting for rate regulated operations (continued)

Deferred electricity costs (recoveries)

Variances between ATCO Electric's actual and forecast transmission access payments may arise due to changes in tariffs charged by the Alberta Power Pool. The amount included in customer rates is based on forecast cost. Revenues are adjusted for changes in tariffs, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AUC and not adjusted for variances between forecast and actual costs.

In Alberta, major transmission capital projects are planned by the Alberta Power Pool and directly assigned to one of the transmission facility owners in the province. Revenue requirement includes a return on forecast rate base. Whereas actual capital costs may vary from forecast capital costs, variances may arise between the return on forecast rate base and the return on actual rate base. Revenues are adjusted for these variances, and the variances are deferred until approval from the AUC is obtained for refund to or collection from the Alberta Power Pool, which is expected to occur in the following year. GAAP requires that revenues be based on the rates approved by the AUC and not adjusted for variances between the returns on forecast and actual rate base.

Variances between ATCO Electric's actual and forecast income tax provision may arise due to changes in enacted and substantively enacted tax rates. The amount included in customer rates is based on forecast tax rates. Revenues are adjusted for changes in enacted and substantively enacted tax rates, and the variances are deferred until approval from the AUC is obtained for refund to or collection from customers, which is expected to occur in the following year. GAAP requires that revenues be based on customer rates approved by the AUC and not adjusted for variances between forecast and actual tax rates.

Consequently, revenues in 2007 would have been $9.4 million lower (2006 – $1.2 million lower) in the absence of rate regulation.

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

The AUC has directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and to refund to customers the future income taxes of $34.4 million collected under the previously allowed tax methodology (see Note 3). As a result of this decision, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $49.3 million in the third quarter of 2007, offset by a regulatory asset of $14.9 million which represents current income tax savings to be realized in future periods. There was no effect on earnings as revenues and income taxes were both initially reduced by $34.4 million. There will also be no effect on earnings in future periods as the current income tax savings realized in future periods will be offset by a reduction in revenues as the regulatory asset is reversed.

In the fourth quarter of 2007, the liability to customers and the regulatory asset were reduced by $0.7 million due to a reduction in future income tax rates. Furthermore, in December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers, thereby realizing $5.2 million of current income tax savings, which further reduced revenues, and reducing the future income taxes to be refunded by $10.9 million. The total reduction in revenues and income taxes in 2007 was $39.6 million.

ATCO Electric will be refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008, of which $6.7 million is included in current liabilities and $25.8 million is included in deferred credits (see Note 13). As these amounts are refunded, ATCO Electric will realize the remaining $9.0 million of current income tax savings and eliminate the remaining $23.5 million of future income taxes to be refunded. GAAP requires that revenues not be adjusted for the current income tax savings to be realized in future periods.

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

2. Accounting for rate regulated operations (continued)

Deferred hearing costs

The utilities incur hearing costs on an ongoing basis associated with various AUC regulatory proceedings. These costs are comprised primarily of legal and consulting expenses incurred by the utilities in addition to costs incurred by intervenor groups that have been reimbursed by the utilities as directed by the AUC. Hearing costs are deferred to the balance sheet and are expensed using AUC approved annual amounts that are collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the next general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that hearing costs be expensed in the period in which they are incurred. Consequently, expenses in 2007 would have been \$3.0 million higher (2006 – \$6.8 million lower) in the absence of rate regulation.

Reserves for injuries and damages

The AUC has approved the use of reserves for injuries and damages by the utilities as a means of self-insurance. The reserves for injuries and damages are established based on annual amounts approved by the AUC to be expensed by each utility and collected through customer rates. Variances between the approved annual amounts and actual costs incurred are deferred until the following general rate application or until a specific application is made to the AUC requesting recovery from or refund to customers. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2007 would have been \$1.2 million higher (2006 – \$3.6 million lower) in the absence of rate regulation.

For Alberta Power (2000), reserves for injuries and damages are recoverable under the terms of the PPA's on a straight line basis through 2008. GAAP requires that claims be expensed in the period in which they are incurred. Consequently, expenses in 2007 would have been \$1.0 million lower (2006 – \$1.0 million lower) in the absence of rate regulation.

Deferred royalty credits

Under the terms of PPA's, the compensation for certain royalties incurred by Alberta Power (2000) for coal supply are averaged over the term of each PPA. As such, royalty costs incurred are deferred and expensed on the same average cost basis as reflected in the underlying PPA revenues. GAAP requires that royalty costs be expensed in the period in which they are incurred. Consequently, expenses in 2007 would have been \$3.4 million lower (2006 – \$1.6 million lower) in the absence of rate regulation.

Other regulatory assets and liabilities

Other regulatory assets and liabilities include the following:

a) On December 13, 2006, the AUC issued a decision approving the distribution of the proceeds from the sale of the Red Deer Operating Centre, which occurred in 2005, to ATCO Gas. GAAP requires that gains and losses related to asset dispositions be recognized in the period the disposition was made. Consequently, revenues in 2006 would have been \$1.0 million lower in the absence of rate regulation.

b) ATCO Pipelines has received AUC approval to defer the variances between actual and AUC approved forecast revenues and costs associated with the movement (receipt or delivery) of natural gas between ATCO Pipelines' system and other connected pipeline systems. ATCO Pipelines has applied for approval to recover these deferral account balances in its general rate application which was filed with the AUC on October 1, 2007. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2007 would have been \$0.1 million higher (2006 – \$0.9 million higher) and expenses would have been \$0.2 million lower (2006 – \$0.6 million lower) in the absence of rate regulation. Assets of \$2.5 million and \$0.2 million (2006 – \$2.7 million and \$0.2 million) are included in current regulatory assets and non-current regulatory assets, respectively, and liabilities of \$0.9 million are included in non-current regulatory liabilities (2006 – \$0.5 million in current regulatory liabilities and \$0.3 million in non-current regulatory liabilities).

2. Accounting for rate regulated operations (continued)

c) ATCO Pipelines has received AUC approval to establish a deferral account for the Salt Cavern Storage facility to collect (i) the revenue requirements for return on rate base and associated income taxes related to the necessary working capital for the natural gas in storage, and (ii) the gains or losses associated with the sale of natural gas in the market upon withdrawal from storage. ATCO Pipelines is required to submit an application to the AUC, either separately or in conjunction with a general rate application for that particular year, requesting recovery from or refund to customers of the deferral amount should the deferral account exceed $2.0 million at the end of the annual injection/withdrawal cycle on March 31 of a particular year. ATCO Pipelines has applied for approval to recover this deferral account balance in its general rate application which was filed with the AUC on October 1, 2007. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2007 would have been $2.2 million lower (2006 – $2.6 million lower) in the absence of rate regulation. Assets of $5.9 million are included in non-current regulatory assets (2006 – $3.7 million) in the balance sheet.

d) ATCO Pipelines has received AUC approval to establish deferral accounts to collect the costs and revenues arising from load balancing transactions. Load balancing requires the purchase or sale of natural gas to maintain appropriate operating pressures on ATCO Pipelines' North and South transmission pipeline systems. Should the deferral account for either North or South exceed $2.0 million, ATCO Pipelines may submit an application to the AUC requesting recovery from or refund to customers of that particular deferral amount. GAAP requires that actual revenues and costs be recognized in the period in which they are earned or incurred. Consequently, revenues in 2007 would have been $4.7 million higher (2006 – $8.9 million higher expenses) in the absence of rate regulation. Assets of $4.2 million are included in current regulatory assets in the balance sheet (2006 – $8.9 million).

e) ATCO Electric, ATCO Gas and ATCO Pipelines have provided interest free market differential loans to employees when relocating; however, ATCO Electric's revenue requirement includes a recovery from customers for imputed interest on these loans. Effective January 1, 2007, the CICA recommendations regarding the measurement of financial assets require that these loans be measured at fair value, resulting in a reduction in their carrying amount. ATCO Electric defers the variances between the fair value and face value of the loans as a regulatory asset. GAAP requires that the variances be recorded as compensation expense upon issue of the loans, with subsequent accretion according to the effective interest method over their respective terms. Consequently, revenues for 2007 would have been $1.1 million lower in the absence of rate regulation. Assets of $2.5 million are included in non-current regulatory assets.

Other items affected by rate regulation

The AUC permits an allowance for funds used ("AFU"), based on each utility's weighted average cost of capital, to be included in rate base. AFU is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFU component, will be approved for inclusion in future customer rates. Since AFU includes preferred share and common equity components, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

The utilities and the generating plants of Alberta Power (2000) follow the method of accounting for income taxes that is consistent with the method of determining the income tax component of its rates. When future income taxes are not included in the income tax component of current rates, such future income taxes are not recognized to the extent that they will be recovered from customers through inclusion in future rates. GAAP requires the recognition of all future income tax liabilities and future tax assets in the absence of rate regulation (see Note 6).

3. Regulatory matters

On September 22, 2007, ATCO Electric received a decision on its General Tariff Application for 2007 and 2008 which was filed with the AUC in November 2006. The decision established the amount of revenue ATCO Electric can recover through its rates for electric distribution and transmission service provided to its customers for 2007 and 2008. The effect of the decision on the earnings of ATCO Electric was not material, as higher revenues primarily resulting from increased investment in capital expenditures and previously approved interim customer rates were offset by lower allowed rate of return on common equity (8.51% in 2007 versus 8.93% in 2006) and other adjustments.

The decision also directed ATCO Electric to change its income tax methodology for federal purposes, whereby, effective January 1, 2007, ATCO Electric no longer recognizes future income taxes, and to refund to customers the future income taxes of $34.4 million collected under the previously allowed tax methodology. As a result of this decision, ATCO Electric recorded a reduction in future income tax liabilities of $34.4 million and a liability to customers of $49.3 million in the third quarter of 2007, offset by a regulatory asset of $14.9 million which represents current income tax savings to be realized in future periods. There was no effect on earnings as revenues and income taxes were both initially reduced by $34.4 million. There will also be no effect on earnings in future periods as the current income tax savings realized in future periods will be offset by a reduction in revenues as the regulatory asset is reversed.

In the fourth quarter of 2007, the liability to customers and the regulatory asset were reduced by $0.7 million due to a reduction in future income tax rates. Furthermore, in December 2007, ATCO Electric refunded $16.1 million of the liability to transmission customers, thereby realizing $5.2 million of current income tax savings, which further reduced revenues, and reducing the future income taxes to be refunded by $10.9 million. The total reduction in revenues and income taxes in 2007 was $39.6 million.

ATCO Electric will be refunding the remaining $32.5 million to distribution customers over a five year period commencing in 2008, of which $6.7 million is included in current liabilities and $25.8 million is included in deferred credits (see Note 13). As these amounts are refunded, ATCO Electric will realize the remaining $9.0 million of current income tax savings (see Note 2) and eliminate the remaining $23.5 million of future income taxes to be refunded.

In January 2006, ATCO Gas received a decision on its general rate application which was filed with the AUC in May 2005 for the 2005, 2006 and 2007 test years. The decision established the amount of revenue ATCO Gas can recover through distribution rates for natural gas distribution service to its customers over the period of 2005 to 2007. The decision also approved the return on common equity as determined by the AUC's standardized rate of return methodology. The rate of return on common equity was 8.93% in 2006 and 8.51% for 2007. The final impact of the decision is subject to the outcome of an existing process regarding the pricing of services provided by ATCO I-Tek. A benchmarking report was received on January 23, 2008, and an application is anticipated to be made to the AUC by the end of February 2008 to finalize the placeholder costs. A decision from the AUC is expected before the end of the second quarter of 2008.

In November 2007, ATCO Gas filed a general rate application with the AUC for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. ATCO Gas has filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Gas received a decision from the AUC approving interim adjustable rate increases amounting to 50% of ATCO Gas' requested revenue increase. A decision from the AUC is not expected until the third quarter of 2008.

In October 2007, ATCO Pipelines filed a general rate application for 2008 and 2009 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with an increased rate base in Alberta. A decision from the AUC is not expected until the fourth quarter of 2008. In November 2007, ATCO Pipelines filed an application requesting interim adjustable rates pending the AUC's decision on the general rate application. In December 2007, ATCO Pipelines received a decision from the AUC approving interim adjustable rate increases amounting to 40% of ATCO Pipelines' requested revenue increase.

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

4. TXU Europe settlement

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") which had a long term "off take" agreement for 27.5% of the power produced by the 1,000 megawatt Barking generating plant in London, England, in which the Corporation, through Barking Power, has a 25.5% equity interest. Barking Power had filed a claim for damages for breach of contract related to TXU Europe's obligations to purchase 27.5% of the power produced by the Barking generating plant. Following negotiations with the administrators, an agreement was reached with respect to Barking Power's claim.

In settlement of its claim, Barking Power received distributions of £144.5 million (approximately $327 million) in 2005, of which the Corporation's share was $83.1 million, and distributions of £34.8 million (approximately $71 million) in 2006, of which the Corporation's share was $18.2 million. Income taxes of approximately $28.5 million relating to the distributions have been paid.

The Corporation's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2007, earnings after income taxes of approximately $10 million per year have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

On May 31, 2007, £95.0 million of the TXU proceeds, of which the Corporation's share was $52.7 million, were applied to Barking Power's non-recourse long term debt.

5. Interest and other income

	2007	2006
Interest	**$46.4**	$39.3
Allowance for funds used by regulated operations	**9.7**	9.3
Gains on dispositions of property, plant and equipment and other investments	**3.2**	8.3
Gain on natural gas purchase contracts derivative asset (Note 21)	**13.5**	-
Loss on power generation revenue contract liability (Note 21)	**(9.4)**	-
Cash flow hedge losses	**(0.5)**	-
Other	**1.4**	1.6
	$64.3	$58.5

6. Income taxes

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

	2007		2006	
Earnings before income taxes	**$498.7**	**%**	$526.8	%
Income taxes, at statutory rates	**$160.2**	**32.1**	$171.2	32.5
Part VI.1 tax benefit	**(15.6)**	**(3.1)**	-	-
Change in method of accounting for future income taxes in certain regulated operations	**(34.4)**	**(6.9)**	(4.0)	(0.8)
Unrecorded future income taxes relating to regulated operations	**(4.9)**	**(1.0)**	2.5	0.5
Change in future income taxes resulting from reduction in tax rates	**(14.9)**	**(3.0)**	(12.2)	(2.3)
Future income taxes recorded at less than current statutory rates	**(3.6)**	**(0.7)**	(1.5)	(0.3)
Foreign tax rate variance	**(3.6)**	**(0.7)**	(2.0)	(0.4)
Non-deductible interest on foreign financing	**1.4**	**0.3**	1.3	0.2
ATCO Gas tax reassessments	**(8.8)**	**(1.8)**	(1.2)	(0.2)
H.R. Milner income tax reassessment	**-**	**-**	7.4	1.4
Resource allowance	**-**	**-**	(1.6)	(0.3)
Crown royalties and other non-deductible Crown payments	**-**	**-**	0.7	0.1
Other	**1.9**	**0.4**	6.5	1.3
	77.7	**15.6**	167.1	31.7
Current income taxes	**112.6**		183.0	
Future income tax recoveries	**$ (34.9)**		$ (15.9)	

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

	2007	2006
Property, plant and equipment	**$185.2**	$230.6
Deferred assets and liabilities	**(33.5)**	(35.5)
Tax loss carryforwards	**(0.6)**	(0.1)
Derivative financial instruments	**3.4**	-
Other	**1.0**	-
	155.5	195.0
Less: Amounts included in current future income taxes	**1.7**	0.3
	$153.8	$194.7

At December 31, 2007, unrecorded future income tax liabilities of the regulated operations amounted to $159.4 million and unrecorded future income tax assets of other operations amounted to $0.8 million. The liabilities include $4.7 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's.

On June 15, 2007, an amendment to tax legislation pertaining to the taxation of preferred share dividends paid by corporations (Part VI.1 tax) received third reading in the House of Commons. The Canada Revenue Agency ("CRA") has been assessing corporate tax returns based on this proposed change since January 1, 2003, resulting in a reduction of taxes paid to the CRA. As this change is now considered to have been substantively enacted, the Corporation recorded a reduction to current income tax expense related to years prior to 2007 of $15.6 million. Funds generated by operations increased by $15.6 million, offset by a similar reduction in changes in non-cash working capital, leaving the Corporation's cash position unchanged.

6. **Income taxes** (continued)

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

In 2006, the CRA issued a reassessment for Alberta Power (2000)'s 2001 taxation year. The CRA's reassessment treats the proceeds received from the sale of the H.R. Milner generating plant to the Alberta Balancing Pool as income rather than as a sale of an asset. The Corporation has appealed the reassessment to the Tax Court of Canada. The full impact of the reassessment was a $12.4 million increase in interest and income tax expense, a $12.4 million decrease in earnings, and a $28.8 million payment associated with the tax and interest assessed. It is expected that $16.4 million of this cash payment will be recovered by reducing income taxes payable through higher capital cost allowance claims.

There are tax loss carryforwards of $0.4 million for a Canadian subsidiary corporation and $4.6 million for a foreign subsidiary corporation for which no tax benefit has been recorded. The losses for the Canadian subsidiary corporation begin to expire in 2010 and the losses for the foreign subsidiary corporation do not expire.

Income taxes paid amounted to $135.6 million (2006 — $187.0 million).

7. Retained earnings at beginning of period as restated

	January 1	
	2007	2006
Retained earnings at beginning of period as previously reported	**$1,804.4**	$1,721.9
Adjustments to retained earnings to recognize the prior years' effect of:		
(a) the fair value of the natural gas purchase contracts derivative asset (net of income taxes)	**41.6**	-
(b) the fair value of the power generation revenue contract liability associated with the natural gas purchase contracts derivative asset (net of income taxes)	**(31.6)**	-
(c) the change in method of accounting for long term debt and non-recourse long term debt at amortized cost using the effective interest method (net of income taxes)	**(0.6)**	-
(d) the fair value of receivables (net of income taxes)	**(0.5)**	-
Retained earnings at beginning of period as restated	**$1,813.3**	$1,721.9

8. Purchase of Class A shares and other direct charges to retained earnings

	2007	2006
Purchase of Class A shares	**$7.2**	$64.4
Purchase of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. (Note 19)	**-**	0.3
	$7.2	$64.7

9. Property, plant and equipment

	Composite Depreciation Rates	2007 Cost	2007 Accumulated Depreciation	2006 Cost	2006 Accumulated Depreciation
Utilities	3.7%	**$ 7,036.4**	**$2,589.7**	$6,490.4	$2,411.1
Power Generation	3.3%	**2,839.9**	**1,093.9**	2,853.7	1,026.1
Global Enterprises	7.5%	**313.3**	**148.6**	269.5	140.8
Other	4.8%	**26.7**	**8.0**	26.7	6.7
		$10,216.3	**3,840.2**	$9,640.3	3,584.7
Property, plant and equipment less accumulated depreciation			**6,376.1**		6,055.6
Unamortized contributions by utility customers for extensions to plant			**697.6**		629.5
			$5,678.5		$5,426.1

Accumulated depreciation includes amounts provided for future removal and site restoration costs, net of salvage value, of $417.0 million (2006 — $374.6 million).

Composite depreciation rates reflect total depreciation in the year as a percentage of mid-year cost, excluding construction work-in-progress of $142.5 million (2006 — $114.2 million) and non-depreciable assets of $52.9 million (2006 — $52.3 million).

10. Other assets

	2007	2006
Accrued pension asset (Note 20)	**$139.5**	$157.1
Security deposits for debt	**19.6**	22.8
Deferred financing charges for debt (1)	**-**	25.0
Deferred financing charges for equity preferred shares (2)	**2.7**	-
Other	**32.5**	24.8
	$194.3	$229.7

(1) *Commencing January 1, 2007, in accordance with CICA recommendations regarding the presentation of financial liabilities, long term debt and non-recourse long term debt have been reduced by their respective cumulative unamortized balance of deferred financing charges. Amortization of deferred financing charges for debt, which was recorded in interest expense, amounted to $3.5 million (2006 – $2.8 million).*

(2) *Amortization of deferred financing charges for equity preferred shares, which was recorded in interest expense, amounted to $0.2 million (2006 – nil).*

11. Lines of credit

At December 31, 2007, the Corporation has the following lines of credit that enable it to obtain financing for general business purposes:

	2007 Total	2007 Used	2007 Available	2006 Total	2006 Used	2006 Available
Long term committed	**$ 326.0**	**$48.2**	**$277.8**	$326.0	$47.4	$278.6
Short term committed	**600.0**	**10.0**	**590.0**	600.0	14.0	586.0
Uncommitted	**74.1**	**12.9**	**61.2**	69.1	7.1	62.0
	$1,000.1	**$71.1**	**$929.0**	$995.1	$68.5	$926.6

11. Lines of credit (continued)

Of the $71.1 million used at December 31, 2007, $47.0 million is included in long term debt and $24.1 million represents outstanding letters of credit.

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

The CICA recommendations regarding the measurement of financial liabilities require the financial liabilities to be measured at initial recognition, including transaction costs, minus principal repayments, plus or minus the cumulative amortization using the effective interest method of any difference between that initial amount and the maturity amount, minus any reduction for impairment. Accordingly, deferred financing charges have been recalculated using the effective interest method. Commencing January 1, 2007, in accordance with CICA recommendations regarding the presentation of financial liabilities, long term debt and non-recourse long term debt have been reduced by their respective cumulative unamortized balance of deferred financing charges.

Long term debt

	Effective Interest Rate	2007	2006
Canadian Utilities			
CU Inc. debentures – unsecured			
2002 4.801% due November 2007	4.913%	**$ -**	$ 50.0
2000 6.97% due June 2008	7.062%	**100.0**	100.0
1989 Series 10.20% due November 2009	10.331%	**125.0**	125.0
1990 Series 11.40% due August 2010	11.537%	**125.0**	125.0
2000 7.05% due June 2011	7.130%	**100.0**	100.0
2007 4.883% due November 2012	4.990%	**35.0**	-
2004 5.096% due November 2014	5.162%	**100.0**	100.0
2002 6.145% due November 2017	6.217%	**150.0**	150.0
2004 5.432% due January 2019	5.492%	**180.0**	180.0
1999 6.8% due August 2019	6.861%	**300.0**	300.0
1990 Second Series 11.77% due November 2020	11.903%	**100.0**	100.0
2006 4.801% due November 2021	4.854%	**160.0**	160.0
1991 Series 9.92% due April 2022	10.063%	**125.0**	125.0
1992 Series 9.40% due May 2023	9.511%	**100.0**	100.0
2004 5.896% due November 2034	5.939%	**200.0**	200.0
2005 5.183% due November 2035	5.226%	**185.0**	185.0
2006 5.032% due November 2036	5.072%	**160.0**	160.0
2007 5.556% due October 2037	5.598%	**220.0**	-
CU Inc. other long term obligation, due June 2009, unsecured	6.000%	**4.5**	4.5
Canadian Utilities Limited debentures – unsecured			
2002 6.14% due November 2012	6.228%	**100.0**	100.0
Less: Deferred financing charges		**(13.3)**	-
		2,556.2	2,364.5
ATCO Midstream Ltd. credit facility, at BA rates, due June 2012, unsecured [1]	Floating	**25.0**	25.0
ATCO Power Canada Ltd. credit facility, at BA rates, due August 2012, secured by a pledge of cash [1]	Floating	**22.0**	22.0
		$2,603.2	$2,411.5

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

Non-recourse long term debt

The CICA recommendations pertaining to financial instruments do not permit the presentation of interest rate swaps in combination with floating rate long term debt to emulate fixed rate long term debt. Consequently, any of the Corporation's floating rate non-recourse long term debt that had previously been presented in combination with interest rate swaps is now presented exclusive of the effect of the interest rate swaps (see Note 21). The comparative figures have been restated; this change in presentation had no effect on the amount of the Corporation's non-recourse long term debt.

Project Financing	Effective Interest Rate	**2007**	2006
Barking Power Limited payable in British pounds:			
Term loans, at fixed rates averaging 7.95%, due to 2010:			
(£17.9 million (2006 – £22.8 million))	7.95%	**$ 35.1**	$ 52.1
Term loan, at LIBOR, due to 2008 (1):			
(£5.2 million (2006 – £37.5 million))	Floating	**10.2**	85.5
Osborne Cogeneration Pty Ltd., payable in Australian dollars:			
Term loan, at Bank Bill rates, due to 2013 (1):			
($31.9 million AUD (2006 – $36.4 million AUD))	Floating (2)	**27.7**	33.5
ATCO Power Alberta Limited Partnership ("APALP"):			
Term loan, at LIBOR, due to 2016 (1)	Floating (2)	**77.0**	90.0
Joffre:			
Term loan, at BA rates, due to 2012 (1)	Floating (2)	**0.4**	5.6
Term facility, at Canadian Prime Advances, due to 2012 (1)	Floating (2)	**0.1**	-
Term loan, at LIBOR, due to 2012 (1)	Floating (2)	**0.8**	10.0
Notes, at fixed rate of 8.59%, due to 2020	8.845%	**32.0**	32.0
Scotford:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**42.5**	42.5
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**10.7**	0.3
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**-**	10.7
Notes, at fixed rate of 7.93%, due to 2022	8.302%	**25.3**	26.1
Muskeg River:			
Term loan, at BA rates, due to 2014 (1)	Floating (2)	**32.5**	32.7
Term facility, at Canadian Prime Advances, due to 2014 (1)	Floating (2)	**0.1**	-
Term loan, at LIBOR, due to 2014 (1)	Floating (2)	**8.1**	8.2
Notes, at fixed rate of 7.56%, due to 2022	7.902%	**27.6**	29.4
Brighton Beach:			
Term loan, at BA rates, due to 2020 (1)	Floating (2)	**19.2**	20.2
Term loan, at LIBOR, due to 2020 (1)	Floating (2)	**17.3**	18.1
Construction overrun facility, at BA rates, due to 2020 (1)	Floating (2)	**4.7**	4.9
Construction overrun facility, at LIBOR, due to 2020 (1)	Floating (2)	**4.3**	4.5
Notes, at fixed rate of 6.924%, due to 2024	7.025%	**104.9**	107.8

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

Non-recourse long term debt (continued)

Project Financing	Effective Interest Rate	2007	2006
Cory:			
Cost overrun facility, at BA rates, due to 2011 [1]	Floating [2]	**2.4**	3.0
Notes, at fixed rate of 7.586%, due to 2025	7.872%	**35.5**	36.5
Notes, at fixed rate of 7.601%, due to 2026	7.880%	**31.5**	32.4
Less: Deferred financing charges		**(6.4)**	-
		543.5	686.0
Less: Amounts due within one year		**65.4**	59.3
		$478.1	$626.7

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

(1) *The above interest rates have additional margin fees at a weighted average rate of 1.2% (2006 — 1.1%). The margin fees are subject to escalation.*

(2) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 21).*

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, 2007 was $1,235.6 million (2006 — $1,415.2 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:

a) **Construction liens** – Represents liens currently registered against project assets. Effective September 30, 2005, ATCO Power entered into an indemnity agreement with Brighton Beach Power Ltd. obligating it to cover any cash shortfalls associated with clearing the construction liens registered against the project. This agreement allowed the project to achieve financial completion under the terms of the project financing agreement. The maximum amount of the indemnity is $8.3 million. Canadian Utilities Limited issued a guarantee to Brighton Beach Power Ltd. guaranteeing the payments under the indemnity agreement. The indemnity and the guarantee are reduced as the liens are settled. At December 31, 2007, the value of the guarantee is $8.3 million.

b) **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, 2007, no amounts were outstanding under the guarantee.

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

c) **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, 2007, the amount of the obligations under these guarantees is:

Project	Major Maintenance	Debt Service
APALP project financing	Nil [1]	$ 7.0
Brighton Beach project financing	Nil [2]	Nil
Cory project financing	Nil [1]	$ 3.9
Joffre project financing	Nil [3]	$ 1.6
Muskeg River project financing	Nil [1]	$ 9.0
Scotford project financing	Nil [1]	$12.1

(1) *No major maintenance reserve required for this financing.*
(2) *Reserve requirements of $0.2 million met with project cash flows.*
(3) *Reserve requirements of $0.1 million met with project cash flows.*

d) **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, 2007, the maximum value of the guarantee is $28.8 million.

e) **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, 2007, 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.

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

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 subject to guarantees, excluding Barking Power.

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
2008	$100.0	$ 65.4	$165.4
2009	129.5	46.0	175.5
2010	125.0	50.3	175.3
2011	100.0	42.3	142.3
2012	82.0	38.8	120.8
	$536.5	$242.8	$779.3

Of the $165.4 million due in 2008, $100.0 million is to be refinanced and is, therefore, excluded from long term debt due within one year in the balance sheet.

Interest expense

Interest expense is as follows:

	2007	2006
Long term debt	**$169.1**	$161.0
Non-recourse long term debt	**43.2**	49.0
Notes payable	**-**	0.3
Bank indebtedness	**1.4**	1.5
Amortization of deferred financing charges	**3.7**	2.8
Interest on H.R. Milner income tax reassessment (Note 6)	**-**	8.3
	$217.4	$222.9

Interest paid amounted to $210.6 million (2006 — $220.8 million).

13. Deferred credits

	2007	2006
Accrued other post employment benefits liability (Note 20)	**$ 52.8**	$ 45.1
Deferred availability incentives	**41.8**	39.6
Asset retirement obligations	**73.1**	69.4
Power generation revenue contract liability (Note 21)	**54.2**	-
Liability to customers for refund of future income taxes (Note 3)	**25.8**	-
Deferred revenues (Note 4)	**26.2**	46.8
Accrued equipment repairs and maintenance	**8.6**	7.5
Other	**25.4**	20.6
	$307.9	$229.0

13. Deferred credits (continued)

Deferred availability incentives

Amortization of deferred availability incentives, which was recorded in revenues, amounted to $11.8 million (2006 – $10.6 million).

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

Asset retirement obligations

Changes in asset retirement obligations are summarized below:

	2007	2006
Obligations at beginning of year	**$69.4**	$62.2
Obligations incurred	**0.1**	3.7
Accretion expense	**3.6**	3.5
Obligations at end of year	**$73.1**	$69.4

The Corporation estimates the undiscounted amount of cash flow required to settle the asset retirement obligations is approximately $131 million, which will be incurred between 2008 and 2052. The discount rates used to calculate the fair value of the asset retirement obligations have a weighted average rate of 5.7%.

14. Equity preferred shares

CU Inc. equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	**2007** Shares	**2007** Amount	2006 Shares	2006 Amount
Cumulative Redeemable Preferred Shares						
4.60% Series 1	$25.00	See below	**4,600,000**	**$115.0**	-	$ -

On April 18, 2007, CU Inc., a subsidiary corporation, issued $115.0 million Cumulative Redeemable Preferred Shares Series 1 at a price of $25.00 per share for cash. The dividend rate has been fixed at 4.60%. The net proceeds of the issue were used in part to redeem $91.8 million of the outstanding Cumulative Redeemable Second Preferred Shares Series Q, R and S of ATCO Electric, ATCO Gas and ATCO Pipelines, subsidiary corporations of CU Inc., that are held by Canadian Utilities Limited.

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $94.7 million (2006 - nil).

14. Equity preferred shares (continued)

Redemption privileges

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

Canadian Utilities Limited equity preferred shares

Authorized and issued

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

Issued:

	Stated Value (dollars)	Redemption Dates	2007 Shares	2007 Amount	2006 Shares	2006 Amount
Cumulative Redeemable Second Preferred Shares						
5.9% Series Q	$25.00	Open	-	$ -	2,277,675	$ 56.9
5.3% Series R	$25.00	Open	-	-	2,146,730	53.7
6.6% Series S	$25.00	Open	-	-	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**	6,000,000	150.0
Perpetual Cumulative Second Preferred Shares						
4.35% Series O	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series T	$25.00	December 2, 2011	**1,600,000**	**40.0**	1,600,000	40.0
4.35% Series U	$25.00	December 2, 2011	**800,000**	**20.0**	800,000	20.0
4.70% Series V	$25.00	October 3, 2012	**4,400,000**	**110.0**	4,400,000	110.0
				$510.0		$636.5
Total CU Inc. and Canadian Utilities Limited equity preferred shares				**$625.0**		$636.5

On May 18, 2007, Canadian Utilities Limited redeemed $126.5 million of outstanding Cumulative Redeemable Second Preferred Shares Series Q, R, and S at a price of $25.00 per share plus accrued and unpaid dividends per share.

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

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

Fair values

Fair values for preferred shares determined using quoted market prices for the same or similar issues are $517.3 million (2006 — $666.8 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.

14. Equity preferred shares (continued)

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.

15. 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, 2005	82,876,186	$379.7	44,016,284	$139.4	126,892,470	$519.1
Purchased and cancelled	(1,832,200)	(8.4)	-	-	(1,832,200)	(8.4)
Stock options exercised	327,900	5.3	-	-	327,900	5.3
Converted: Class B to Class A	84,800	0.3	(84,800)	(0.3)	-	-
December 31, 2006	**81,456,686**	**376.9**	**43,931,484**	**139.1**	**125,388,170**	**516.0**
Purchased and cancelled	**(157,800)**	**(0.7)**	**-**	**-**	**(157,800)**	**(0.7)**
Stock options exercised	**64,300**	**1.6**	**-**	**-**	**64,300**	**1.6**
Converted: Class B to Class A	**145,800**	**0.5**	**(145,800)**	**(0.5)**	**-**	**-**
December 31, 2007	**81,508,986**	**$378.3**	**43,785,684**	**$138.6**	**125,294,670**	**$516.9**

From January 1, 2008 to February 15, 2008, 46,400 Class B common shares were converted to Class A non-voting shares.

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	
	2007	2006	**2007**	2006
	(Unaudited)			
Weighted average shares outstanding	**125,390,562**	125,321,693	**125,409,080**	126,218,722
Effect of dilutive stock options	**564,511**	512,786	**525,057**	468,457
Weighted average diluted shares outstanding	**125,955,073**	125,834,479	**125,934,137**	126,687,179

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

15. Class A and Class B shares (continued)

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 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.

Normal course issuer bid

On May 23, 2006, Canadian Utilities Limited commenced a normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid expired on May 22, 2007. Over the life of the bid, 1,679,700 shares were purchased, all of which were purchased in 2006. On May 23, 2007, Canadian Utilities commenced a new normal course issuer bid for the purchase of up to 5% of the outstanding Class A shares. The bid will expire on May 22, 2008. From May 23, 2007, to February 15, 2008, 157,800 shares have been purchased, all of which were purchased in 2007.

Special dividend

The Corporation paid a Special Dividend of $0.25 per Class A non-voting and Class B common share on September 1, 2006.

16. Stock based compensation plans

Stock option plan

Of the 6,400,000 Class A non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 3,122,200 Class A non-voting shares are available for issuance at December 31, 2007. 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:

	2007		2006	
	Class A Shares	**Weighted Average Exercise Price**	Class A Shares	Weighted Average Exercise Price
Options at beginning of year	**1,208,000**	**$25.12**	1,415,500	$21.59
Granted	**163,500**	**47.82**	121,000	43.45
Exercised	**(64,300)**	**22.91**	(327,900)	16.62
Cancelled	**(3,000)**	**47.84**	(600)	24.52
Options at end of year	**1,304,200**	**$28.02**	1,208,000	$25.12

16. Stock based compensation plans (continued)

Information about stock options outstanding at December 31, 2007 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
$17.23 - $18.87	331,300	1.9	$17.86	331,300	$17.86
$20.65 - $28.65	487,400	2.3	23.54	473,000	23.47
$30.25 - $47.84	485,500	7.9	39.46	105,800	33.47
$17.23 - $47.84	1,304,200	4.3	$28.02	910,100	$22.59

In 2007, Canadian Utilities Limited granted 163,500 options to purchase Class A non-voting shares at a weighted average exercise price of $47.82 per share. The options have a term of ten years and vest over the first five years.

Changes in contributed surplus are summarized below:

	2007	2006
Contributed surplus at beginning of year	**$1.2**	$ 0.7
Stock option expense	**0.7**	0.5
Contributed surplus at end of year	**$1.9**	$ 1.2

The Corporation uses the Black-Scholes option pricing model, which estimated the weighted average fair value of the options granted during 2007 at $7.23 per option (2006 — $6.24 per option) using the following weighted average assumptions:

	2007	2006
Risk free interest rate	**4.0%**	4.0%
Expected holding period prior to exercise	**6.2 years**	6.2 years
Share price volatility	**12.5%**	11.9%
Estimated annual Class A share dividend	**2.5%**	2.5%

Share appreciation rights

Directors, officers and key employees of the Corporation may be granted share appreciation rights that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting Shares of ATCO Ltd. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. The base value of the share appreciation rights is equal to the weighted average of the trading 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 $0.7 million (2006 — $2.4 million).

17. Changes in non-cash working capital

	2007	2006
Operating activities, changes related to:		
Accounts receivable	**$(15.8)**	$(25.6)
Inventories	**(3.8)**	0.5
Regulatory assets	**5.1**	(10.6)
Prepaid expenses	**(5.2)**	(3.0)
Accounts payable and accrued liabilities	**21.5**	1.7
Income taxes	**(20.3)**	6.4
Future income taxes	**-**	(3.8)
Regulatory liabilities	**(0.5)**	(5.2)
	$(19.0)	$(39.6)
Investing activities, changes related to:		
Inventories	**$ (2.9)**	$ (8.1)
Prepaid expenses	**(1.1)**	(0.3)
Accounts payable and accrued liabilities	**16.3**	(6.2)
Income taxes	**-**	(3.7)
	$ 12.3	$(18.3)
Financing activities, changes related to:		
Accounts receivable	**$ -**	$ (0.1)

18. Joint ventures

The Corporation's interest in joint ventures is summarized below:

	2007	2006
Statement of earnings		
Revenues	**$ 484.9**	$ 533.0
Operating expenses	**291.0**	328.1
Depreciation and amortization	**42.1**	40.4
Interest	**36.1**	41.2
	115.7	123.3
Interest and other income	**13.3**	8.9
Earnings from joint ventures before income taxes	**$ 129.0**	$ 132.2
Balance sheet		
Current assets	**$ 165.7**	$ 266.9
Current liabilities	**(142.6)**	(174.0)
Property, plant and equipment	**871.7**	933.2
Deferred items – net	**(50.1)**	(93.1)
Non-recourse long term debt	**(350.4)**	(465.2)
Investment in joint ventures	**$ 494.3**	$ 467.8

18. Joint ventures (continued)

	2007	2006
Statement of cash flows		
Operating activities	**$ 143.6**	$ 180.8
Investing activities	**(17.7)**	(19.1)
Financing activities	**(208.0)**	(131.0)
Foreign currency translation	**(10.7)**	14.1
Increase (decrease) in cash position	**$ (92.8)**	$ 44.8

Current assets include cash of $65.2 million (2006 — $160.9 million) which is only available for use within the joint ventures.

19. Related party transactions

In transactions with ATCO Ltd. and its wholly owned subsidiary corporations, the Corporation sold fuel in the amount of $2.0 million (2006 — $2.2 million), provided computer operations and systems development services totaling $6.7 million (2006 – $2.4 million), recovered administrative expenses totaling $1.6 million (2006 — $2.4 million) and incurred administrative expenses and corporate signature rights totaling $8.3 million (2006 — $8.6 million). The Corporation also incurred capital expenditures of $9.4 million (2006 — nil) that were recorded in property, plant and equipment.

In transactions with entities related through common control, the Corporation provided security services and recovered administrative expenses totaling $0.3 million (2006 – $0.2 million) and incurred advertising, promotion and administrative expenses totaling $1.5 million (2006 — $1.7 million).

At December 31, 2007, accounts receivable due from related parties amounted to $0.8 million (2006 – $4.9 million) and accounts payable due to related parties amounted to $8.3 million (2006 – $3.2 million).

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

On October 1, 2006, the Corporation purchased the common shares of ATCO Európa Szerkezetgyártó és Kereskedelmi Kft. from an affiliate corporation for $0.5 million cash, partially offset by the forgiveness of $0.4 million of debt owed by the Corporation to the affiliate corporation. This purchase was recorded at carrying value, resulting in a charge to retained earnings of $0.3 million.

20. Employee future benefits

The Corporation maintains registered defined benefit and defined contribution pension plans for most of its employees and provides other post employment benefits, principally health, dental and life insurance, for retirees and their dependants. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan and employees participating in the defined benefit pension plans may transfer to the defined contribution pension plan at any time. Upon transfer, further accumulation of benefits under the defined benefit pension plans ceases. The Corporation also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

20. Employee future benefits (continued)

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

	2007		2006	
	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	**$1,704.1**	**$ -**	$1,561.1	$ -
Actual return on plan assets	**30.7**	**-**	187.3	-
Employee contributions	**3.8**	**-**	3.7	-
Employer contributions	**0.7**	**-**	-	-
Benefit payments	**(41.2)**	**-**	(39.8)	-
Payments to defined contribution plans (1)	**(9.5)**	**-**	(8.2)	-
End of year	**$1,688.6**	**$ -**	$1,704.1	$ -
Accrued benefit obligations:				
Beginning of year	**$1,642.0**	**$ 83.5**	$1,485.0	$ 80.3
Current service cost	**39.8**	**2.6**	38.0	3.0
Interest cost	**86.3**	**4.2**	80.8	4.2
Employee contributions	**3.8**	**-**	3.7	-
Benefit payments from plan assets (2)	**(41.2)**	**-**	(39.8)	-
Benefit payments by employer	**(4.3)**	**(2.0)**	(4.3)	(1.8)
Experience losses (gains) (3)	**(75.7)**	**(8.9)**	78.6	(2.2)
End of year (4)	**$1,650.7**	**$ 79.4**	$1,642.0	$ 83.5
Funded status:				
Excess (deficiency) of assets over obligations (4)	**$ 37.9**	**$(79.4)**	$ 62.1	$(83.5)
Amounts not yet recognized in financial statements:				
Unrecognized net cumulative experience losses on plan assets and accrued benefit obligations	**289.1**	**8.2**	316.0	17.7
Unrecognized net transitional liability (asset)	**(187.5)**	**18.4**	(221.0)	20.7
Accrued asset (liability) (Notes 10, 13)	**$ 139.5**	**$(52.8)**	$ 157.1	$(45.1)
Regulatory asset (liability) (5) (Note 2)	**$ (110.0)**	**$ 32.3**	$ (118.7)	$ 27.6

(1) *Employer contributions for certain of the Corporation's defined contribution pension plans are paid from the assets of the defined benefit pension plans.*

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

(3) *A change in the liability discount rate at December 31 assumption resulted in experience gains in 2007 of approximately $99 million, whereas a change in the average compensation rate increase assumption for the year resulted in experience losses in 2007 of approximately $29 million for the pension benefit plans. Changes in assumptions regarding the average compensation rate increase for the year and age at retirement resulted in experience losses in 2006 of approximately $66 million for the pension benefit plans.*

(4) *The non-registered, non-funded defined benefit pension plans had accrued benefit obligations of $84.0 million at December 31, 2007 (2006 – $84.2 million). Apart from these obligations, the excess of assets over obligations for the registered defined benefit pension plans at December 31, 2007 was $121.9 million (2006 – $146.3 million).*

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

20. Employee future benefits (continued)

	2007		2006	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Benefit plan cost				
Components of benefit plan cost:				
Current service cost	**$ 39.8**	**$ 2.6**	$ 38.0	$ 3.0
Interest cost	**86.3**	**4.2**	80.8	4.2
Actual return on plan assets	**(30.7)**	**-**	(187.3)	-
Experience losses (gains) on accrued benefit obligations	**(75.7)**	**(8.9)**	78.6	(2.2)
	19.7	**(2.1)**	10.1	5.0
Adjustments to recognize long term nature of employee future benefits:				
Unrecognized portion of actual return on plan assets	**(64.4)**	**-**	107.6	-
Unrecognized portion of experience gains (losses) on accrued benefit obligations	**75.7**	**8.9**	(78.6)	2.2
Amortization of net cumulative experience losses on plan assets and accrued benefit obligations	**15.6**	**0.6**	24.5	2.0
Amortization of net transitional liability (asset)	**(33.5)**	**2.3**	(32.4)	2.3
	(6.6)	**11.8**	21.1	6.5
Defined benefit plans cost	**13.1**	**9.7**	31.2	11.5
Defined contribution plans cost	**11.0**	**-**	9.7	-
Total cost	**24.1**	**9.7**	40.9	11.5
Less: Capitalized	**2.1**	**2.5**	1.9	2.7
Less: Unrecognized defined benefit plans cost (income) (1) (2)	**7.8**	**2.9**	19.5	3.5
Net cost recognized (2)	**$ 14.2**	**$ 4.3**	$ 19.5	$ 5.3

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

(2) *Net cost recognized for pension benefit plans in 2007 includes the amortization of $2.6 million (2006 – $5.1 million) of the deferred pension assets recorded by the Corporation upon the adoption of the current accounting standard in 2000. On October 11, 2006, the AUC approved recovery of these assets for a nine-year period commencing January 1, 2005 (Note 2).*

In the unaudited three months ended December 31, 2007, net cost of $3.0 million (2006 – $7.8 million) was recognized for pension benefit plans and net cost of $1.0 million (2006 – $1.6 million) was recognized for other post employment benefit plans.

20. Employee future benefits (continued)

Weighted average assumptions

	2007		2006	
	Pension Benefit Plans	**Other Post Employment Benefit Plans**	Pension Benefit Plans	Other Post Employment Benefit Plans
Assumptions regarding benefit plan cost:				
Expected long term rate of return on plan assets for the year	**6.6%**	-	6.1%	-
Liability discount rate for the year	**5.1%**	**5.1%**	5.1%	5.1%
Average compensation increase for the year	(1)	-	3.5%	-
Assumptions regarding accrued benefit obligations:				
Liability discount rate at December 31	**5.5%**	**5.5%**	5.1%	5.1%
Long term inflation rate	**2.5%**	(2)	2.5%	(2)

(1) *The assumed average compensation increases are 4.0% for five years (2007-2011) and 3.5% thereafter.*

(2) *The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 7.8% for 2007 grading down over 6 years to 4.5% (2006 – 8.5% for 2006 grading down over 7 years to 4.5%), and, for other medical and dental costs, 4.0% for 2007 and thereafter (2006 – 4.0% for 2006 and thereafter).*

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2007 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.

	2007 Pension Benefit Plans		2007 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase (1)	-	$ (4.0)	-	-
1% decrease (1)	-	$ 4.0	-	-
Liability discount rate				
1% increase (1)	$ (82.3)	$(5.6)	$(3.7)	$(0.3)
1% decrease (1)	$104.9	$ 8.4	$ 4.6	$ 0.4
Future compensation rate				
1% increase (1)	$ 21.9	$ 3.0	-	-
1% decrease (1)	$(20.1)	$(2.8)	-	-
Long term inflation rate				
1% increase (1) (2) (3)	$ 36.5	$ 4.5	$ 3.9	$ 0.6
1% decrease (1) (3)	$(63.8)	$(7.7)	$(3.1)	$(0.4)

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

(2) *The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.*

(3) *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.*

20. Employee future benefits (continued)

Pension benefit plan assets

	2007		2006	
	Amount	**%**	Amount	%
Plan asset mix:				
Equity securities [1]	**$1,000.4**	**59.3**	$1,028.7	60.4
Fixed income securities [2]	**621.7**	**36.8**	605.6	35.5
Real estate [3]	**37.2**	**2.2**	32.7	1.9
Cash and other assets [4]	**29.3**	**1.7**	37.1	2.2
	$1,688.6	**100.0**	$1,704.1	100.0

(1) *Equity securities consist of investments in domestic and foreign preferred and common shares. At December 31, 2007, the market values of investments in United States' securities and international equities, denominated in a number of different currencies, are $114.9 million and $308.1 million, respectively (2006 – $236.7 million and $238.2 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.*

At December 31, 2007, plan assets include long term debt of CU Inc. having a market value of $12.2 million (2006 – $8.7 million), Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $18.5 million (2006 – $19.1 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of $20.0 million (2006 – $18.2 million).

Funding

Employees are required to contribute a percentage of their salary to the registered defined benefit pension plans. The Corporation is required to provide the balance of the funding, based on triennial actuarial valuations, necessary to ensure that benefits will be fully provided for at retirement. Based on the most recent actuarial valuation for funding purposes as of December 31, 2006 the Corporation is continuing a contribution holiday that began on April 1, 1996 for all but one of the registered pension plans; commencing in 2007, the Corporation is required to make annual contributions of approximately $0.7 million to cover the unfunded liability of that plan. The next actuarial valuation for funding purposes is required as of December 31, 2009.

21. Risk management and financial instruments

The Corporation 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 United Kingdom and the Global Enterprises segment is affected by the cost of natural gas and the price of natural gas liquids. In conducting its business, the Corporation may use various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes.

At December 31, 2007, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows associated with a portion of non-recourse long term debt, foreign currency forward contracts that hedge foreign currency risk on the future cash flows associated with specific firm commitments or anticipated transactions and certain natural gas purchase contracts.

21. Risk management and financial instruments (continued)

The derivative assets and liabilities comprise the following:

	2007
Derivative assets – current:	
Interest rate swap agreements	$ 0.2
Foreign currency forward contracts	0.6
	$ 0.8
Derivative assets – non-current:	
Natural gas purchase contracts	$72.5
Interest rate swap agreements	0.8
	$73.3
Derivative liabilities – current:	
Interest rate swap agreements	$ 1.5
Foreign currency forward contracts	1.1
	$ 2.6
Derivative liabilities – non-current:	
Interest rate swap agreements	$ 3.3

Interest rate risk

The Corporation has converted variable rate non-recourse long term debt to fixed rate debt through the following interest rate swap agreements:

Project Financing	Swap Fixed Interest Rate [1]	Variable Debt Interest Rate	Maturity Date	Notional Principal 2007	Notional Principal 2006
Osborne: ($30.3 million AUD (2006 – $34.6 million AUD))	7.333%	Bank Bill Rate in Australia	December 2013	$ 26.3	$ 31.8
APALP:	7.790%	90 day BA	November 2008	1.3	2.6
	7.567%	90 day BA	December 2008	1.8	3.6
	7.750%	6 month LIBOR	December 2011	73.7	83.8
Joffre:	7.286%	90 day BA	September 2012	19.8	24.0
Scotford:	5.332%	90 day BA	September 2008	51.4	54.2
Muskeg River:	5.287%	90 day BA	December 2007	-	40.8
	5.515%	90 day BA	December 2012	32.6	-
	5.615%	3 month LIBOR	December 2012	8.2	-
Brighton Beach:	5.837%	30 day BA	June 2009	8.5	8.9
	6.575%	90 day BA	March 2019	34.2	36.1
Cory:	6.586%	90 day BA	June 2011	2.1	2.7
				$259.9	$288.5

BA – Bankers' Acceptance
LIBOR – London Interbank Offered Rate

[1] *The above swap fixed interest rates include any long term debt margin fees; the margin fees are subject to escalation (Note 12).*

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 98% (2006 – 96%) of total long term debt and non-recourse long term debt.

21. Risk management and financial instruments (continued)

Foreign exchange rate risk

The Corporation has exposure to changes in the carrying values of its foreign operations, including assets and liabilities, as a result of changes in exchange rates. Gains or losses on translation of self-sustaining foreign operations are included in the foreign currency translation adjustment account in accumulated other comprehensive income. Gains or losses on translation of integrated foreign operations are recognized in earnings.

The Corporation has entered into foreign currency forward contracts in order to fix the exchange rate on certain service contracts, planned equipment expenditures and operational cash flows denominated in U.K. pounds sterling ("£"), U.S. dollars and Euros. At December 31, 2007, the contracts consist of purchases of £0.7 million, \$3.1 million U.S. and 7.0 million Euros, and sales of 33.0 million Euros (2006 – purchases of \$0.2 million U.S. and sales of 3.0 million Euros).

Natural gas purchase contracts and associated power generation revenue contract liability

The Corporation has long term contracts for the supply of natural gas for certain of its power generation projects. Under the terms of certain of these contracts, the volume of natural gas that the Corporation is entitled to take is in excess of the natural gas required to generate power. As the excess volume of natural gas can be sold, the Corporation is required to designate these entire contracts as derivative instruments. The Corporation recognized a non-current derivative asset of \$59.0 million on January 1, 2007; thereafter, the Corporation will record mark-to-market adjustments through earnings as the fair values of these contracts change with changes in future natural gas prices. These natural gas purchase contracts mature in November 2014.

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, on January 1, 2007, the Corporation recognized a provision for a power generation revenue contract in the amount of \$44.8 million; thereafter, the Corporation will record adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset. This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment increased the derivative asset by \$14.1 million and \$13.5 million, respectively, for the unaudited_three months and year ended December 31, 2007; the associated power generation revenue contract liability increased by \$10.2 million and \$9.4 million, respectively, for the unaudited_three months and year ended December 31, 2007. At December 31, 2007, the natural gas purchase contracts derivative asset is \$72.5 million and the power generation revenue contract liability is \$54.2 million. The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability increased earnings by \$2.8 million, net of income taxes, for the unaudited three months ended December 31, 2007 and increased earnings by \$2.9 million, net of income taxes, for the year ended December 31, 2007.

Credit risk

For cash and short term investments and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. 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.

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.

21. **Risk management and financial instruments** (continued)

Fair value of non-derivative financial instruments

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

	2007		2006	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Assets				
Cash and short term investments [1]	**$ 747.2**	**$ 747.2**	$ 798.8	$ 798.8
Accounts receivable [1]	**373.9**	**373.9**	362.3	362.3
Liabilities				
Accounts payable and accrued liabilities [2]	**375.0**	**375.0**	338.8	338.8
Liability to customers for refund of future income taxes (Note 13) [3]	**25.8**	**25.8**	-	-
Long term debt [3]	**2,603.2**	**2,907.5**	2,411.5	2,788.4
Non-recourse long term debt [3]	**543.5**	**578.0**	686.0	718.1

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

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

(3) Recorded at amortized cost. Fair values are determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Corporation's current borrowing rate for similar borrowing arrangements.

Fair value of derivative financial instruments

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

	2007			2006		
	Notional Principal [1]	**Fair Value Receivable (Payable) [3]**	**Maturity**	Notional Principal [1]	Fair Value Receivable (Payable) [3]	Maturity
Interest rate swaps	**$259.9**	**$(3.8)**	**2008-2019**	$288.5	$(7.3)	2007-2019
Foreign currency Forward contracts	**$ 62.6**	**$(0.5)**	**2008**	$ 4.6	$ 0.3	2007
Natural gas purchase contracts	**N/A [2]**	**$72.5**	**2014**	N/A [4]	N/A [4]	N/A [4]

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

(2) The notional amount for the natural gas purchase contracts is the maximum volumes that can be purchased over the terms of the contracts.

(3) Fair values for the interest rate swaps and the foreign currency forward contracts have been estimated using period-end market rates, and fair values for the natural gas purchase contracts have been estimated using period-end forward market prices for natural gas. These fair values approximate the amount that the Corporation would either pay or receive to settle the contract at December 31.

(4) In accordance with the CICA recommendations for financial instruments, disclosures not required in financial statements for periods prior to January 1, 2007 need not be provided on a comparative basis.

22. Other comprehensive income

Other comprehensive income ("OCI") of the Corporation is comprised of three components: the unrealized gains and losses on effective cash flow hedging instruments, the unrealized gains and losses on financial assets that are available for sale, and the foreign currency translation adjustment relating to self-sustaining foreign operations.

Changes in the components of accumulated OCI are summarized below:

	Three Months Ended December 31		Year Ended December 31	
	2007	2006	**2007**	2006
Accumulated OCI at beginning of period:				
Cash flow hedge losses [1]	**$ (5.1)**	$ -	**$ -**	$ -
Financial assets available for sale [2]	**0.1**	-	**-**	-
Foreign currency translation adjustment	**(21.3)**	(15.0)	**3.1**	(18.2)
	(26.3)	(15.0)	**3.1**	(18.2)
Adjustment to accumulated OCI at beginning of period due to change in method of accounting for:				
Cash flow hedge losses [3]	**-**	-	**(7.4)**	-
Financial assets available for sale [2]	**-**	-	**0.1**	-
	-	-	**(7.3)**	-
OCI for the period:				
Changes in fair values of cash flow hedges [4]	**0.5**	-	**2.7**	-
Transfers of cash flow hedge losses to earnings [2]	**-**	-	**0.1**	-
Transfer of gain on financial assets available for sale to earnings [2]	**(0.1)**	-	**(0.1)**	-
	0.4	-	**2.7**	-
Foreign currency translation adjustment	**(7.2)**	18.1	**(31.6)**	21.3
	(6.8)	18.1	**(28.9)**	21.3
Accumulated OCI at end of period:				
Cash flow hedge losses [5]	**(4.6)**	-	**(4.6)**	-
Financial assets available for sale	**-**	-	**-**	-
Foreign currency translation adjustment	**(28.5)**	3.1	**(28.5)**	3.1
	$(33.1)	$ 3.1	**$(33.1)**	$ 3.1

(1) *Net of income taxes of $2.2 million.*
(2) *Net of income taxes of nil.*
(3) *Net of income taxes of $3.2 million.*
(4) *Net of income taxes of $(0.3) million and $(1.3) million, respectively.*
(5) *Net of income taxes of $1.9 million and $1.9 million, respectively.*

23. Commitments and contingencies

Commitments

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

	2008	2009	2010	2011	2012	Total of All Subsequent Years
Operating leases [(1)]	$ 16.3	$ 10.4	$ 9.7	$ 7.2	$ 4.5	$ 13.6
Purchase obligations:						
Coal purchase contracts [(2)]	49.3	50.4	51.3	52.9	54.4	296.3
Natural gas purchase contracts [(3)]	50.3	50.4	48.8	20.1	11.1	6.3
Operating and maintenance agreements [(4)]	19.4	16.6	17.8	17.9	13.9	68.9
Other	3.9	2.0	0.3	0.3	0.3	0.2
	$139.2	$129.8	$127.9	$98.4	$84.2	$385.3

(1) *Operating leases are comprised primarily of long term leases for office premises and equipment.*
(2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants.*
(3) *Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants.*
(4) *ATCO Power and Alberta Power (2000) have long term service agreements with suppliers to provide operating and maintenance services at certain of their generating plants.*

Contingencies

Measurement inaccuracies occur from time to time with respect to ATCO Electric's, ATCO Gas' and ATCO Pipelines' metering facilities. Measurement adjustments are settled between the parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow-up are found to be inadequate by the AUC.

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

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

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Although ATCO Gas and ATCO Electric transferred to DEML certain retail functions, including the supply of natural gas and electricity to customers and billing and customer care functions, the legal obligations of ATCO Gas and ATCO Electric remain if DEML fails to perform. In certain events (including where DEML fails to supply natural gas and/or electricity and ATCO Gas and/or ATCO Electric are ordered by the AUC to do so), the functions will revert to ATCO Gas and/or ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and/or ATCO Electric.

23. Commitments and contingencies (continued)

Centrica plc, DEML's parent, has provided a $300 million guarantee, supported by a $235 million letter of credit in respect of DEML's obligations to ATCO Gas, ATCO Electric and ATCO I-Tek in respect of the ongoing relationships contemplated under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to cover all of the costs that could arise in the event of a reversion of such functions.

Canadian Utilities Limited has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek's payment and indemnity obligations to DEML contemplated under the transaction agreements.

24. Segmented information

Description of segments

The Corporation operates in the following business segments:

The **Utilities** Business Group includes the regulated distribution of natural gas by ATCO Gas, the regulated transmission and distribution of water by CU Water, the regulated transmission of natural gas by ATCO Pipelines, the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, and the provision of non-regulated complementary projects by ATCO Energy Solutions (formerly ATCO Utility Services).

The **Power Generation** Business Group includes the non-regulated supply of electricity and cogeneration steam by ATCO Power, the regulated supply of electricity by Alberta Power (2000), and the sale of fly ash and other combustion byproducts produced in coal fired electrical generating plants by ASHCOR Technologies.

The **Global Enterprises** Business Group includes the non-regulated gathering, processing, storage, purchase and sale of natural gas by ATCO Midstream, the provision of project management and technical services for customers in the industrial, defence and transportation sectors by ATCO Frontec, the development, operation and support of information systems and technologies and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek and the sale of travel services to both business and consumer sectors by ATCO Travel. The Corporation sold its 50% interest in Genics, a manufacturer of wood preservation products, effective August 1, 2006.

The Corporate and Other segment includes commercial real estate owned by the Corporation in Alberta.

Segmented results – Three months ended December 31

2007 2006	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
(Unaudited)						
Revenues – external	**$306.8** $308.4	**$193.9** $226.7	**$155.8** $135.6	**$ 0.6** $ 0.4	**$ -** $ -	**$657.1** $671.1
Revenues – intersegment [(1)]	**6.5** 6.3	**-** -	**42.4** 38.3	**2.9** 2.9	**(51.8)** (47.5)	**-** -
Revenues	**$313.3** $314.7	**$193.9** $226.7	**$198.2** $173.9	**$ 3.5** $ 3.3	**$(51.8)** $(47.5)	**$657.1** $671.1
Earnings attributable to Class A and Class B shares	**$ 48.0** $ 43.7	**$ 25.5** $ 36.9	**$ 27.7** $ 27.3	**$(4.1)** $(6.5)	**$ 1.6** $ (1.4)	**$ 98.7** $100.0

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

24. **Segmented information** (continued)

Segmented results – Year ended December 31

2007 2006	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	**$1,091.4**	**$ 773.0**	**$538.6**	**$ 1.9**	**$ -**	**$2,404.9**
	$1,086.2	$ 799.5	$543.3	$ 1.4	$ -	$2,430.4
Revenues – intersegment [(i)]	**25.1**	**-**	**134.0**	**11.7**	**(170.8)**	**-**
	24.6	-	123.9	11.3	(159.8)	-
Revenues	**1,116.5**	**773.0**	**672.6**	**13.6**	**(170.8)**	**2,404.9**
	1,110.8	799.5	667.2	12.7	(159.8)	2,430.4
Operating expenses	**640.6**	**422.6**	**486.1**	**18.6**	**(166.3)**	**1,401.6**
	601.4	431.3	490.5	18.7	(151.2)	1,390.7
Depreciation and amortization	**223.7**	**97.2**	**29.1**	**1.5**	**-**	**351.5**
	220.2	95.4	31.5	1.4	-	348.5
Interest expense	**140.6**	**79.0**	**2.9**	**171.9**	**(177.0)**	**217.4**
	132.5	92.2	2.2	162.4	(166.4)	222.9
Interest and other income	**(16.6)**	**(20.6)**	**(2.7)**	**(201.4)**	**177.0**	**(64.3)**
	(20.3)	(11.9)	(4.1)	(188.6)	166.4	(58.5)
Earnings before income taxes	**128.2**	**194.8**	**157.2**	**23.0**	**(4.5)**	**498.7**
	177.0	192.5	147.1	18.8	(8.6)	526.8
Income taxes	**(22.2)**	**57.6**	**47.2**	**(1.2)**	**(3.7)**	**77.7**
	45.4	69.7	46.1	8.7	(2.8)	167.1
	150.4	**137.2**	**110.0**	**24.2**	**(0.8)**	**421.0**
	131.6	122.8	101.0	10.1	(5.8)	359.7
Dividends on equity preferred shares	**10.7**	**2.5**	**-**	**21.1**	**-**	**34.3**
	10.4	3.6	-	21.8	-	35.8
Earnings attributable to Class A and Class B shares	**$ 139.7**	**$ 134.7**	**$110.0**	**$ 3.1**	**$ (0.8)**	**$ 386.7**
	$ 121.2	$ 119.2	$101.0	$ (11.7)	$ (5.8)	$ 323.9
Total assets	**$4,103.0**	**$2,187.4**	**$345.2**	**$562.5**	**$ 87.3**	**$7,285.4**
	$3,799.0	$2,240.0	$278.1	$576.2	$100.2	$6,993.5
Purchase of property, plant and equipment	**$ 588.9**	**$ 49.2**	**$ 62.7**	**$ -**	**$ -**	**$ 700.8**
	$ 505.0	$ 48.1	$ 14.2	$ 0.4	$ -	$ 567.7

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

Geographic segments

	Domestic		Foreign		Consolidated	
	2007	2006	**2007**	2006	**2007**	2006
Revenues	**$2,143.8**	$2,130.6	**$261.1**	$299.8	**$2,404.9**	$2,430.4
Property, plant and equipment	**$5,369.5**	$5,099.5	**$309.0**	$326.6	**$5,678.5**	$5,426.1

FILE NO. 82-34744

Form 52-109F1 - Certification of Annual Filings

I, Karen M. Watson, Senior Vice President & Chief Financial Officer of Canadian Utilities Limited, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of **Canadian Utilities Limited** (the issuer) for the period ending December 31, 2007;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared;

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

(c) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: February 20, 2008

[Original signed by K.M. Watson]

Senior Vice President
& Chief Financial Officer

Form 52-109F1 - Certification of Annual Filings

I, Nancy C. Southern, President & Chief Executive Officer of Canadian Utilities Limited, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of **Canadian Utilities Limited** (the issuer) for the period ending December 31, 2007;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

(a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared;

(b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

(c) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: February 20, 2008

[Original signed by N.C. Southern]

President & Chief Executive Officer

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED
An ATCO Company

News Release

CANADIAN UTILITIES LIMITED
Corporate Head Office: 1400, 909 - 11 Avenue S.W., Calgary, Alberta T2R 1N6 Tel: (403) 292-7500

For Immediate Release

February 14, 2008

CANADIAN UTILITIES LIMITED TO RELEASE 2007 YEAR-END RESULTS WEDNESDAY, FEBRUARY 20, 2008

CALGARY, Alberta – Canadian Utilities Limited (TSX: CU, CU.X) will release its financial results for the fourth quarter and the full year ended December 31, 2007 on Wednesday, February 20, 2008. The news release will be distributed via www.marketwire.com and the results, including Financial Statements, Management's Discussion & Analysis and the Annual Information Form, will be posted on www.canadian-utilities.com.

Canadian Utilities Limited is part of the ATCO Group of Companies (www.atco.com). Canadian Utilities Limited is a Canadian based worldwide organization of companies with assets of approximately $7.1 billion and more than 6,000 employees, actively engaged in three main business divisions: Power Generation; Utilities (natural gas and electricity transmission and distribution) and Global Enterprises, with companies active in technology, logistics and energy services.

More information about Canadian Utilities Limited can be found on its website www.canadian-utilities.com.

For further information, please contact:

K.M. (Karen) Watson
Senior Vice President &
Chief Financial Officer
Canadian Utilities Limited
(403) 292-7502

Forward-Looking Information:

Certain statements contained in this news release may constitute forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "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.

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, prevailing economic conditions, and other factors, many of which are beyond the control of the Corporation.

The forward-looking statements contained in this news release represent the Corporations' expectations as of the date hereof, and are subject to change after such date. The Corporation disclaims any intention or obligation to update or revise any forward-looking statements whether as a result of new information, future events or otherwise, except as required under applicable securities regulations.

FILE NO. 82-34744

CIBC Mellon Trust Company | CIBC Mellon

February 15, 2008

Nova Scotia Securities Commission

Alberta Securities Commission

The Manitoba Securities Commission

Ontario Securities Commission

Registrar of Securities, Prince Edward Island

L'Autorité des marchés financiers

Securities Commission of Newfoundland and Labrador

Saskatchewan Financial Services Commission, Securities Division

Office of the Administrator of the Securities Act, New Brunswick

British Columbia Securities Commission

The Toronto Stock Exchange

Dear Sirs:

RE: Canadian Utilities Limited

Pursuant to a request from our Principal, we wish to advise you of the following dates in connection with their Annual Meeting of Shareholders:

DATE OF MEETING:	May 7, 2008
RECORD DATE FOR NOTICE:	March 18, 2008
RECORD DATE FOR VOTING:	March 18, 2008
BENEFICIAL OWNERSHIP DETERMINATION DATE:	March 18, 2008
SECURITIES ENTITLED TO NOTICE:	Class A Non-Voting Class B Common
SECURITIES ENTITLED TO VOTE:	Class B Common

Yours very truly,

CIBC MELLON TRUST COMPANY

Jennifer Villareal
Associate Relationship Manager

cc: CDS & Co. (Via Fax)

cc: Canadian Utilities Limited

FILE NO. 82-34744

CANADIAN UTILITIES LIMITED
An ATCO Company

News Release

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2008 MAR 31 P 1:24
OFFICE OF INTERNATIONAL CORPORATE FINANCE

CANADIAN UTILITIES LIMITED
Corporate Head Office: 1400, 909 - 11 Avenue S.W., Calgary, Alberta T2R 1N6 Tel: (403) 292-7500

For Immediate Release

February 20, 2008

SEC Mail Processing Section
MAR 25 2008
Washington, DC

CANADIAN UTILITIES REPORTS RECORD 2007 EARNINGS OF $386.7 MILLION

CALGARY, Alberta – **Canadian Utilities Limited (TSX: CU, CU.X)**

Record earnings of $386.7 million ($3.08 per share) for the year ended December 31, 2007, compared to earnings of $323.9 million ($2.57 per share) for the year ended December 31, 2006 were reported today by Canadian Utilities.

"Canadian Utilities' 2007 record earnings were generated by all three of our diverse business divisions; Power Generation, Utilities and Global Enterprises," said Nancy Southern, President and Chief Executive Officer, Canadian Utilities. "The earnings reflect continued growth in our utility customer base, good performance from our power generation plants and the impact of various income tax adjustments."

Canadian Utilities also reported an increase in "adjusted earnings" in 2007, which excludes certain items not in the normal course of business or a result of day-to-day operations. Adjusted earnings for the year ended December 31, 2007 were $343.8 million ($2.74 per share) compared to $320.8 million ($2.54 per share) for the year ended December 31, 2006. Details are provided in the table below.

Earnings for the three months ended December 31, 2007, were $98.7 million ($0.78 per share), compared to earnings of $100.0 million ($0.80 per share) for the same three months of 2006. Adjusted earnings for the three months ended December 31, 2007 were $75.5 million ($0.60 per share), compared to adjusted earnings of $100.0 million ($0.80 per share) for the same three months of 2006.

RECENT DEVELOPMENTS

- ATCO Gas began servicing its one millionth customer in Alberta as the utility managed robust growth in the province.
- ATCO Power reported on November 5, 2007 that the 1,000 megawatt Barking Power Plant in East London, England, of which ATCO Power owns 25.5%, experienced an unplanned outage on 60% of the plant capacity. This outage reduced Canadian Utilities' 2007 earnings by $8.6 million ("Barking Outage"). The plant is expected to resume operations in March 2008. Business interruption and property insurance is expected to cover the majority of the outage losses after December 9, 2007.
- ATCO I-Tek, for the second consecutive year, received the "Top Customer Satisfaction Award in North American Energy Industry" for its operation of the ATCO Gas and ATCO Electric Call Centre.
- ATCO Electric received all regulatory approvals to proceed with construction of a new 226 kilometre transmission line required to support increasing power needs in fast-growing northwest Alberta. The 240-kilovolt line, which will extend from the Wabasca area to the Peace River region, is expected to be completed by March 31, 2010 at an estimated project cost of $210 million.

[continued]

Financial Summary and Reconciliation of Adjusted Earnings	**For the Three Months Ended December 31**		**For the Twelve Months Ended December 31**	
	2007	2006	**2007**	2006
($ Millions except per share data)	*(unaudited)*			
Reported Earnings	**98.7**	100.0	**386.7**	323.9
H.R. Milner Income Tax Reassessment	**-**	-	**-**	12.4
2006 Changes in Income Taxes and Rates	**-**	-	**-**	(11.8)
Calgary Stores Block Gain	**-**	-	**-**	(3.7)
2007 Changes in Income Taxes and Rates	**(10.9)**	-	**(14.9)**	-
2007 Changes in Preferred Share Taxes	**-**	-	**(15.6)**	-
ATCO Power Mark-to Market Adjustment	**(2.8)**	-	**(2.9)**	-
ATCO Gas Tax Reassessments	**(9.5)**	-	**(9.5)**	-
Adjusted Earnings (1)	**75.5**	100.0	**343.8**	320.8
Earnings per share	**0.78**	0.80	**3.08**	2.57
Adjusted Earnings per share (1)	**0.60**	0.80	**2.74**	2.54
Revenues	**657.1**	671.1	**2,404.9**	2,430.4
Funds generated by operations (2)	**180.0**	168.4	**725.9**	657.5

(1) This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

(2) This measure is cash generated from operations before changes in non-cash working capital and is not defined by Generally Accepted Accounting Principles. This measure may not be comparable to similar measures used by other companies.

Adjusted earnings for the twelve months ended December 31, 2007, increased primarily due to colder temperatures, higher sales per customer and customer growth in ATCO Gas, and the timing and demand of natural gas storage capacity sold, higher storage fees and higher margins for natural gas liquids (NGL) extraction in ATCO Midstream. This increase was partially offset by increased operation and maintenance and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures, and lower earnings in ATCO Power's Alberta generating plants due to lower spark spreads realized on sales of electricity and the impact of the Barking Outage.

Adjusted earnings for the three months ended December 31, 2007, decreased primarily due to lower earnings in ATCO Power's Alberta generating plants due to lower spark spreads realized on sales of electricity and the impact of the Barking Outage, increased operation and maintenance and depreciation expenses in ATCO Gas due to customer growth and increased capital expenditures and warmer temperatures in ATCO Gas. This decrease was partially offset by higher prices and volumes of natural gas processed for NGL extraction operations in ATCO Midstream, and decreased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I share prices since September 30, 2007.

Revenues for the twelve months ended December 31, 2007, decreased primarily due to the refund of future income tax balances, which also reduced income tax expense, resulting from the ATCO Electric 2007-2008 General Tariff Application Decision received in the third quarter of 2007, lower natural gas fuel purchases recovered on a "no-margin" basis and the impact of the Barking Outage in ATCO Power, and lower prices and volumes of natural gas processed for NGL extraction in ATCO Midstream. This decrease was partially offset by colder temperatures, higher sales per customer and customer growth in ATCO Gas, and the timing and demand of natural gas storage capacity sold and higher storage fees in ATCO Midstream.

Revenues for the three months ended December 31, 2007, decreased primarily due to lower sales in ATCO Power's Alberta generating plants due to lower Alberta Power Pool prices and the impact of the Barking Outage. This decrease was partially offset by higher prices and volumes of natural gas processed for NGL extraction operations in ATCO Midstream, and the recording of green house gas emission fees recovered by Alberta Power (2000) from its customers. It is anticipated that the Power Purchase Arrangements will allow Alberta Power (2000) to recover most of the costs associated with complying with these recent changes in environmental laws.

[continued]

Funds generated by operations for the twelve months ended December 31, 2007, increased primarily due to higher earnings and increased deferred availability incentives in Alberta Power (2000). **Funds generated by operations for the three months ended December 31, 2007,** increased primarily due to increased deferred availability incentives in Alberta Power (2000).

Canadian Utilities Limited's consolidated financial statements and management's discussion and analysis of financial condition and results of operations for the three and twelve months ended December 31, 2007, will be available on Canadian Utilities' website (www.canadian-utilities.com) or via SEDAR (www.sedar.com) or can be requested from the Corporation.

Canadian Utilities Limited is part of the ATCO Group of Companies (www.atco.com). Canadian Utilities Limited is a Canadian based worldwide organization of companies with assets of approximately $7.3 billion and more than 6,500 employees, actively engaged in three main business divisions: Power Generation, Utilities (natural gas and electricity transmission and distribution) and Global Enterprises (technology, logistics and energy services).

For further information, please contact:

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FILE NO. 82-34744

CANADIAN UTILITIES LIMITED
An ATCO Company

FORM 13-502F1

CLASS I REPORTING ISSUERS - PARTICIPATION FEE

For the Year Ending December 31, 2007

FORM 13-502F1
CLASS I REPORTING ISSUERS - PARTICIPATION FEE

Reporting Issuer Name:		**Canadian Utilities Limited**
Fiscal year end date used to calculate capitalization:		**December 31, 2007**

<u>Market value of listed or quoted securities:</u>

Class A Non-Voting Shares:

Total number of securities outstanding as at the most recent fiscal year end:	81,456,686 (i)	
Simple average of the closing price as of the last trading day of each month of the fiscal year (1)	$47.24 (ii)	
Market Value of Class	(i) x (ii) =	$3,848,014,000 (A)

Class B Common Shares:

Total number of securities outstanding as at the most recent fiscal year end:	43,931,484 (i)	
Simple average of the closing price as of the last trading day of each month of the fiscal year (1)	$46.96 (ii)	
Market Value of Class	(i) x (ii) =	$2,063,022,000 (B)

Series W Second Preferred Shares

Total number of securities outstanding as at the most recent fiscal year end:	6,000,000 (i)	
Simple average of the closing price as of the last trading day of each month of the fiscal year (1)	$25.97 (ii)	
Market Value of Class	(i) x (ii) =	$155,820,000 (C)

Series X Second Preferred Shares		
Total number of securities outstanding as at the most recent fiscal year end:	6,000,000 (i)	
Simple average of the closing price as of the last trading day of each month of the fiscal year (1)	$26.26 (ii)	
Market Value of Class	(i) x (ii) =	$157,560,000 (D)
Market value of other securities:		
6.14% Debentures		
Book Value at December 31, 2007	$100,000,000	
Market Value at December 31, 2007	$105.871	
Market Value of Class	$105,871,000	$105,871,000 (E)
Total Capitalization	(A+B+C+D+E)	$6,330,287,000
Participiction Fee		$38,300

Notes:
(1) See Schedule A

Schedule A

Simple Average of Closing Price On
Last Trading Day of Each Month of 2007

	Canadian Utilities Limited			
	Class A Non-Voting Shares	Class B Common Shares	Series W	Series X
December	$46.40	$46.00	$25.80	$26.20
November	50.50	50.73	25.81	25.82
October	54.36	52.60	25.50	26.01
September	48.65	48.45	26.00	26.15
August	48.65	48.02	25.32	26.00
July	47.75	47.70	25.66	25.62
June	46.30	46.18	25.62	25.61
May	49.79	49.56	25.93	25.50
April	45.17	45.20	26.19	27.25
March	42.57	42.50	26.76	27.34
February	43.02	42.85	26.14	26.60
January	43.75	43.75	26.89	27.02
Average	$47.24	$46.96	$25.97	$26.26

END