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.

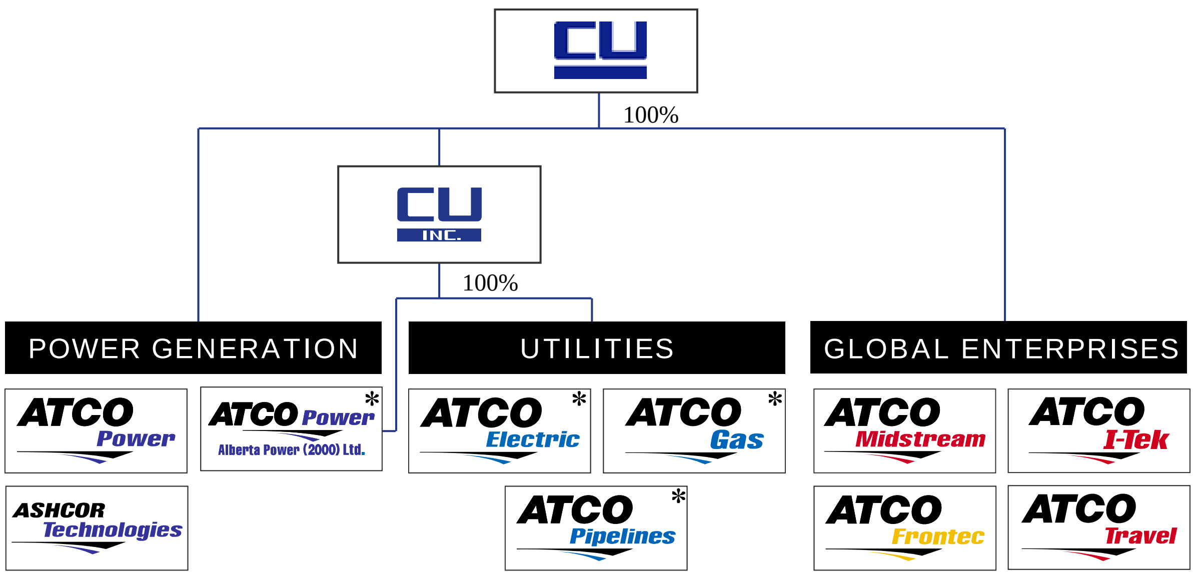
The Corporate and Other segment includes commercial real estate owned by the Company in Alberta.

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:

	Years Prior to 2007	**First Quarter of 2007**	**Total**
($ millions)			
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:

	December 31, 2006 Balance	**First 9 Months of 2007**	**Total**
($ millions)			
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.

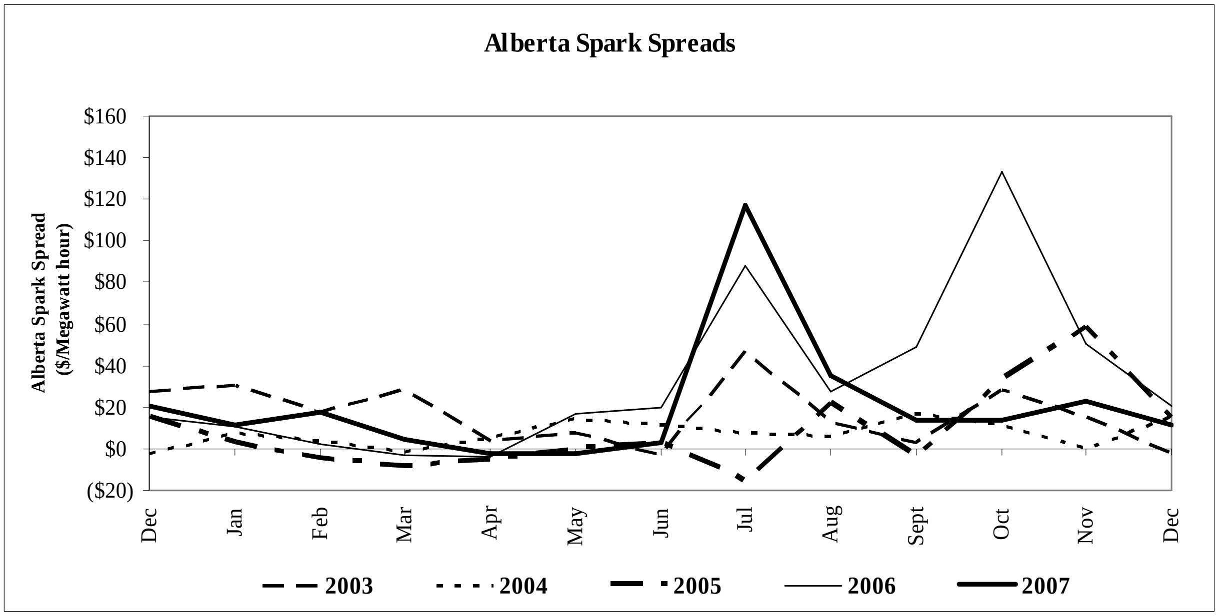
On July 1, 2007, the Piikani Nation of Brockett, Alberta exercised its option to purchase a 25% interest in ATCO Power's and ATCO Resources' 32 MW hydroelectric generating plant at the Oldman River dam near Pincher Creek, Alberta.

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.

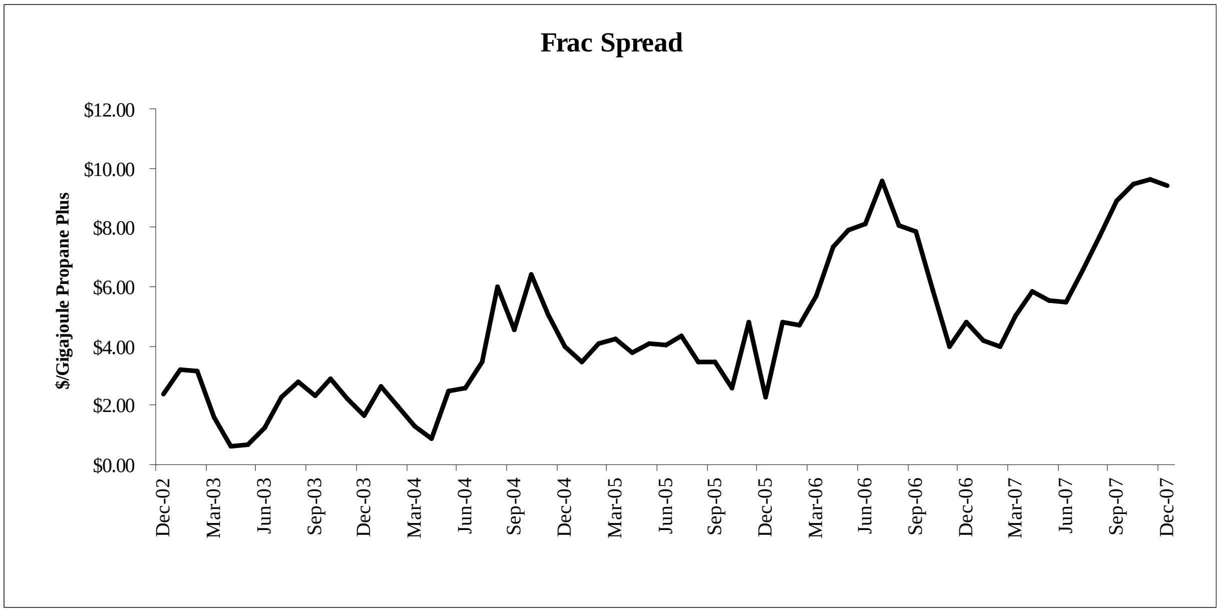
ATCO Midstream

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.



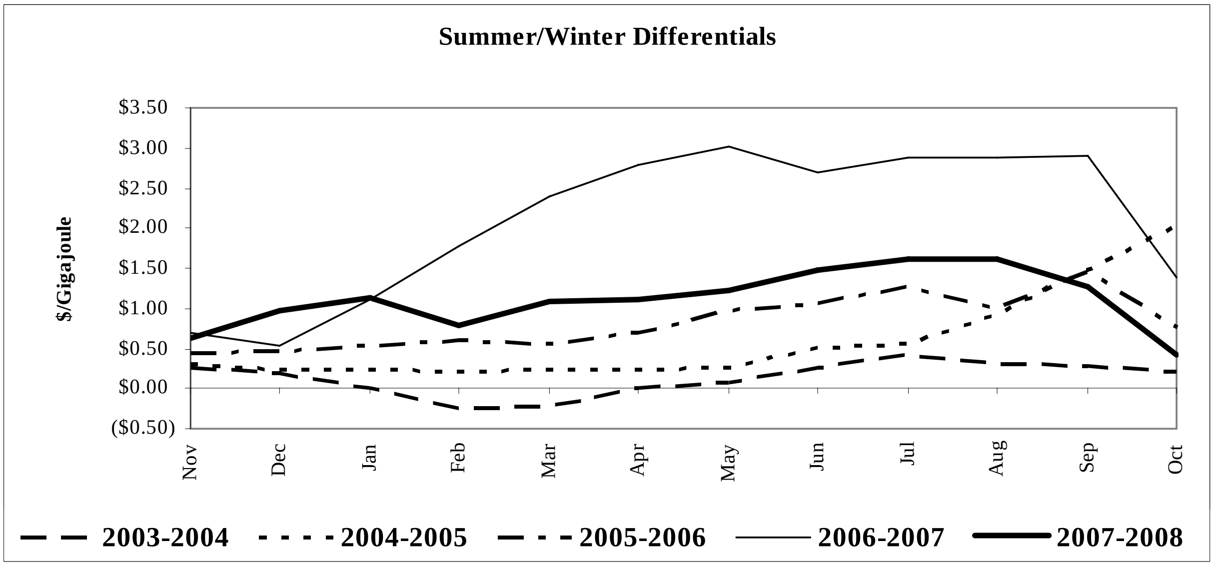
Note:
(1) The above chart represents measurements of Frac spreads in Alberta, as reported by an independent consultant.

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.

	Total	Used	Available
($ millions)			
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				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
($ millions)					
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

($ millions)	For the Three Months Ended December 31		
	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.