

**FOR THE THREE MONTHS ENDED
MARCH 31, 2008**

TO THE SHARE OWNERS:

Canadian Utilities Limited reported earnings of \$150.0 million (\$1.20 per share) for the three months ended March 31, 2008, compared to earnings of \$134.7 million (\$1.07 per share) for the same three months in 2007, were reported by Canadian Utilities.

“Canadian Utilities is reporting strong first quarter earnings as our Utilities and Global Enterprises divisions continue to build on their 2007 performance,” said Nancy Southern, President and Chief Executive Officer, Canadian Utilities. *“We benefited from the growing regulated utilities, increased margins and prices from natural gas liquids extraction, and we restored full production at two large power generating facilities where unplanned outages occurred.”*

Canadian Utilities also reported an increase in “adjusted earnings” for the first quarter, which excludes certain items not in the normal course of business or a result of day-to-day operations. Adjusted earnings for the three months ended March 31, 2008 were \$149.7 million (\$1.19 per share) compared to adjusted earnings of \$130.2 million (\$1.04 per share) for the same three months in 2007.

RECENT DEVELOPMENTS

- On April 28, 2008, ATCO Frontec and their partner, the Fort McKay First Nation, announced that they have been selected by Suncor Energy to create and operate a 1,148-room accommodation complex to support oil sands development north of Fort McMurray, Alberta. ATCO Structures will supply the rooms in modular units. The complex is expected to open on May 25, 2008, and remain in place for a one-year period.
- On April 14, 2008, ATCO Frontec announced the opening of the first phase of their new Creeburn Lake Lodge near Fort McMurray, Alberta. ATCO Frontec also announced that evaluation is underway to consider doubling the capacity in the Lodge to 1,000 rooms.
- On March 6, 2008, ATCO Power announced that its 1,000 megawatt Barking Power Station in East London, England, of which ATCO Power owns 25.5%, resumed full operations. An unplanned outage had reduced the plant’s capacity to approximately 400 megawatts. Insurance proceeds which covered losses incurred during the first quarter of 2008 (earnings of \$8.6 million) and a portion of the losses incurred in 2007 (earnings of \$3.3 million), were recorded in the first quarter of 2008. The final insurance settlement is pending.
- Alberta Power (2000)’s Battle River Unit #4 Generating Station (approximately 150 megawatts) resumed full operations on March 27, 2008. An unplanned outage was originally reported on February 6, 2008.

**Financial Summary and Reconciliation of
Adjusted Earnings**

**For the Three Months
Ended March 31**

	2008	2007
(\$ Millions except per share data)	<i>(unaudited)</i>	
Reported Earnings	150.0	134.7
ATCO Power Mark-to-Market Adjustment	(0.3)	(4.5)
Adjusted Earnings ⁽¹⁾	149.7	130.2
Earnings Per Share	1.20	1.07
Adjusted Earnings Per Share ⁽¹⁾	1.19	1.04
Revenues	740.6	697.6
Funds Generated By Operations ⁽¹⁾⁽²⁾	243.2	232.2

⁽¹⁾ This measure is not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

⁽²⁾ This measure is cash flow from operations before changes in non-cash working capital.

Adjusted earnings for the three months ended March 31, 2008, increased primarily due to the impact of customer growth and Alberta Utilities Commission (AUC) approved interim customer rates associated with the 2008 and 2009 general rate application (“Interim Rates”), the impact of decreased quarterly depreciation expense allocation and colder temperatures in ATCO Gas, and higher margins and prices for natural gas liquids extraction in ATCO Midstream. The change in the ATCO Gas depreciation expense allocation resulted in an increase in ATCO Gas’ earnings of \$4.9 million. As this change relates to the quarterly allocation of full year depreciation expense it will have no impact on full year earnings. These increases were partially offset by the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream.

Revenues for the three months ended March 31, 2008, increased primarily due to increased international operations in ATCO Frontec, Interim Rates, customer growth, higher franchise fees collected on behalf of cities and municipalities and colder temperatures in ATCO Gas, and higher sales of natural gas on a no-margin basis for storage operations in ATCO Midstream. These increases were partially offset by the unplanned outage at the Barking generating plant in ATCO Power’s U.K. operations, net of insurance proceeds.

Funds generated by operations for the three months ended March 31, 2008, increased primarily due to higher earnings partially offset by decreased deferred availability incentives in Alberta Power (2000).

Canadian Utilities Limited is part of the ATCO Group of Companies (www.atco.com). Canadian Utilities Limited is a Canadian-based worldwide organization of companies with assets of approximately \$7.5 billion and more than 6,500 employees, actively engaged in three main business divisions: Power Generation; Utilities (natural gas and electricity transmission and distribution) and Global Enterprises (technology, logistics and energy services).



N.C. Southern
President & Chief Executive Officer



R.D. Southern
Chairman of the Board

CANADIAN UTILITIES LIMITED

Management's Discussion and Analysis (MD&A) For the Three Months Ended March 31, 2008

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements for the three months ended March 31, 2008, and the audited consolidated financial statements and MD&A for the year ended December 31, 2007 (2007 MD&A). **Information contained in the 2007 MD&A that is not discussed in this document remains substantially unchanged.** This MD&A is dated April 28, 2008. Additional information relating to the Company, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com.

Table of Contents

	<u>Page</u>
Glossary.....	3
Company Overview.....	5
Forward-Looking Information.....	5
Non-GAAP Measures.....	6
Internal Control Over Financial Reporting.....	6
Results of Operations.....	7
Selected Quarterly Information.....	7
Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings.....	8
Significant Non-Operating Financial Items.....	8
Consolidated Revenues and Earnings.....	8
Consolidated Expenses.....	9
Segmented Information.....	10
Utilities.....	10
Power Generation.....	12
Global Enterprises.....	15
Corporate and Other.....	16
Liquidity and Capital Resources.....	17
Share Capital.....	18
Business Risks.....	19
Environmental Matters.....	19
Regulated Operations.....	19
Changes in Accounting Policies.....	20

Glossary

Adjusted Earnings means earnings attributable to Class A and Class B shares after adjustments 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

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.

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 cash balances and 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 9 to the unaudited interim consolidated financial statements for the three months ended March 31, 2008.

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 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 adjustments 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 – Selected Quarterly Information section.

Internal Control Over Financial Reporting

There were no changes in the Company’s internal controls over financial reporting that have occurred during the three months ended March 31, 2008, that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Results of Operations

SELECTED QUARTERLY INFORMATION

(\$ millions except per share data)	For the Three Months Ended ^{(1) (2) (3)}			
	Mar. 31	Jun. 30	Sep. 30	Dec. 31
	<i>(unaudited)</i>			
2008				
Revenues	740.6	-	-	-
Earnings attributable to Class A and Class B shares	150.0	-	-	-
Earnings per Class A and Class B share	1.20	-	-	-
Diluted earnings per Class A and Class B share	1.19	-	-	-
Adjusted Earnings ⁽⁴⁾	149.7	-	-	-
Adjusted Earnings per Class A and Class B share ⁽⁴⁾	1.19	-	-	-
2007				
Revenues	697.6	560.3	489.9	657.1
Earnings attributable to Class A and Class B shares	134.7	81.1	72.2	98.7
Earnings per Class A and Class B share	1.07	0.65	0.58	0.78
Diluted earnings per Class A and Class B share	1.07	0.64	0.58	0.78
Adjusted Earnings ⁽⁴⁾	130.2	67.5	70.6	75.5
Adjusted Earnings per Class A and Class B share ⁽⁴⁾	1.04	0.54	0.56	0.60
2006				
Revenues	-	563.4	553.9	671.1
Earnings attributable to Class A and Class B shares	-	70.2	66.8	100.0
Earnings per Class A and Class B share	-	0.56	0.53	0.80
Diluted earnings per Class A and Class B share	-	0.55	0.53	0.80
Adjusted Earnings	-	66.4	67.5	100.0
Adjusted Earnings per Class A and Class B share	-	0.52	0.54	0.80

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, changes in NGL prices and natural gas costs 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 the 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 necessary to understand general trends that have developed and the seasonality of the businesses disclosed in the 2007 MD&A remain substantially unchanged.

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 adjustments 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. A description of each adjustment is provided in the Significant Non-Operating Financial Items section.

	For the Three Months ended March 31		
	2008	2007	Change to 2008 (2008-2007)
(\$ millions)			
Earnings attributable to Class A and Class B shares	150.0	134.7	11.4%
Mark-to-Market Adjustment	(0.3)	(4.5)	(93.3)%
Adjusted Earnings	149.7	130.2	15.0%

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

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

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 \$0.3 million for the three months ended March 31, 2008 (\$4.5 million in 2007). At March 31, 2008, the natural gas purchase contracts derivative asset is \$71.9 million (\$81.9 million in 2007) and the power generation revenue contract liability is \$53.2 million (\$61.3 million in 2007).

CONSOLIDATED REVENUES AND EARNINGS

Consolidated first quarter 2008 **revenues increased** by \$43.0 million (6.2%) over the first quarter of 2007. This increase was primarily attributable to a \$24.8 million (7.2%) increase in revenues in the Utilities segment, and a \$32.2 million (17.7%) increase in revenues in the Global segment. These increases were partially offset by a \$7.1 million (3.4%) decrease in revenues in the Power Generation segment. Revenues in the Corporate and Other segment were substantially unchanged.

Increases in revenues were primarily attributable to increased international operations in ATCO Frontec, AUC approved interim customer rates associated with the 2008 and 2009 general rate application (ATCO Gas Interim Rates), the impact of customer growth, higher franchise fees collected on behalf of cities and municipalities and colder temperatures in ATCO Gas and higher sales of natural gas on a no-margin basis for storage operations in ATCO Midstream. Higher AUC approved customer rates associated with the 2007 and 2008 general tariff application in ATCO Electric (ATCO Electric GTA) also contributed to these increased revenues. These increases were partially offset by the unplanned outage at the Barking generating plant in ATCO Power's U.K. operations, net of insurance proceeds (Barking Outage, refer to Segmented Information - Power Generation - Unplanned Outage at Barking Generating Plant section).

Earnings for the three months ended March 31, 2008 were \$150.0 million, an **increase** of \$15.3 million (11.4%), over the first quarter of 2007, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

For the three months ended March 31, 2008, **Adjusted Earnings** were \$149.7 million, an **increase** of \$19.5 million (15.0%), over the same period of 2007. The primary reasons for the increased Adjusted Earnings were the impact of customer growth and ATCO Gas Interim Rates net of cost increases, the change in quarterly depreciation expense allocation (ATCO Gas Depreciation Expense Adjustment, refer to Segmented Information - ATCO Gas section) and colder temperatures in ATCO Gas, higher margins and prices for NGL extraction in ATCO Midstream and increased international operations in ATCO Frontec. These increases were partially offset by the timing and demand of natural gas storage capacity sold and lower storage fees in ATCO Midstream.

Interest and other income decreased for the first quarter of 2008 by \$6.2 million to \$14.0 million mainly due to the Mark-to-Market Adjustment in ATCO Power.

CONSOLIDATED EXPENSES

(\$ millions)	For the Three Months Ended March 31		
	2008	2007	Change to 2008 (2008-2007)
Operating expenses:			
Natural gas supply	14.9	3.1	380.6%
Purchased power	15.3	13.8	10.9%
Operation and maintenance	244.5	240.6	1.6%
Selling and administrative	51.9	42.4	22.4%
Franchise fees	62.7	58.5	7.2%
	389.3	358.4	8.6%
Depreciation and amortization	90.1	91.9	(2.0)%
Interest	55.9	54.6	2.4%
Dividends on equity preferred shares	8.1	8.8	(8.0)%
Income taxes	61.2	69.4	(11.8)%

Operating expenses for the three months ended March 31, 2008, **increased** by \$30.9 million (8.6%) over the same period in 2007. Natural gas supply increased as a result of higher purchases of natural gas for storage operations in ATCO Midstream. Operation and maintenance expenses were higher primarily as a result of the recording of GHG emission fees by Alberta Power (2000) recovered from its customers in accordance with the PPAs which cover costs of the recent changes in environmental laws (refer to Business Risks - Environmental Matters section), offset by the impact of the Barking Outage. Selling and administrative expenses increased primarily as a result of the impact of inflation, increased salaries and project development costs. Higher franchise fees were collected in ATCO Gas.

For the three months ended March 31, 2008, **depreciation and amortization expenses decreased** by \$1.8 million (2.0%) over the same period in 2007 primarily due to the ATCO Gas Depreciation Expense Adjustment, partially offset by capital additions in 2007 and 2008 in the Utilities segment.

Interest expense for the first quarter of 2008 **increased** by \$1.3 million (2.4%) over the first quarter of 2007, primarily due to increased interest on new financings issued in 2007 to fund capital expenditures in the Utilities segment, partially offset by the repayment of ATCO Power's non-recourse financings in 2008 and 2007.

For the three months ended March 31, 2008, **income taxes decreased** by \$8.2 million (11.8%) over the first quarter of 2007 primarily due to lower corporate income tax rates and lower future income taxes in the Utilities segment resulting from the ATCO Electric GTA, which required ATCO Electric, in the third quarter of 2007, to change its income tax methodology for the recording of Federal Income Taxes. This change in methodology does not affect earnings as ATCO Electric's revenues and income tax expense were reduced by similar amounts. Offsetting this decrease was higher earnings.

SEGMENTED INFORMATION

(\$ millions)	For the Three Months Ended					
	March 31					
	Utilities	Power Generation	Global Enterprises	Corporate & Other	Intersegment Eliminations	Total
2008						
Revenues	369.5	198.8	214.1	3.2	(45.0)	740.6
Earnings attributable to Class A and Class B shares	66.5	35.0	48.9	(0.1)	(0.3)	150.0
Mark-to-Market Adjustment ⁽¹⁾	-	(0.3)	-	-	-	(0.3)
Adjusted Earnings	66.5	34.7	48.9	(0.1)	(0.3)	149.7
2007						
Revenues	344.7	205.9	181.9	3.3	(38.2)	697.6
Earnings attributable to Class A and Class B shares	49.1	43.4	42.8	0.2	(0.8)	134.7
Mark-to-Market Adjustment ⁽¹⁾	-	(4.5)	-	-	-	(4.5)
Adjusted Earnings	49.1	38.9	42.8	0.2	(0.8)	130.2

Note:

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

Utilities

Utilities **revenues** in the first quarter of 2008 **increased** by \$24.8 million (7.2%) from the first quarter of 2007. Items that contributed to increased revenues were the ATCO Gas Interim Rates, the impact of customer growth, higher franchise fees collected on behalf of cities and municipalities and colder temperatures in ATCO Gas and the impact of the ATCO Electric GTA.

Temperatures in ATCO Gas in the first quarter of 2008 were 0.3% warmer than normal, compared to 5.1% warmer than normal in the first quarter of 2007.

In the first quarter of 2008, **earnings and Adjusted Earnings** were \$66.5 million, an **increase** of \$17.4 million (35.4%) over the first quarter of 2007. The primary reasons for the increase were the ATCO Gas Interim Rates net of cost increases, customer growth, the ATCO Gas Depreciation Expense Adjustment and colder temperatures in ATCO Gas and the impact of the ATCO Electric GTA.

Depreciation Expense Adjustment

Effective January 1, 2008, ATCO Gas prospectively changed the allocation of annual depreciation and amortization expense on a quarterly basis. The method of quarterly allocation has been changed from an estimate based on the timing of revenues to the straight line basis, resulting in a reduction to ATCO Gas' depreciation and amortization expense of \$7.1 million in the first quarter of 2008 as compared to the depreciation and amortization expense recorded in the first quarter of 2007. The annual depreciation and amortization expense continues to be on the straight line basis and therefore this change does not affect the total depreciation and amortization expense recognized for the year. This change in allocation resulted in an increase to ATCO Gas' earnings of \$4.9 million for the three months ended March 31, 2008, compared to the three months ended March 31, 2007.

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 for 2007 was 8.51% and for 2008 has been set at 8.75%. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year.

In February 2008, the AUC initiated a generic proceeding to determine if the standardized rate of return methodology established in 2004 should be reviewed. This proceeding will determine if the current methodology continues to yield a fair return on equity for utility companies. Furthermore the AUC is addressing whether the existing AUC approved capital structures for all utility companies should be reviewed in a generic proceeding or, alternatively, to continue to address changes in capital structure in utility company specific rate applications. A decision from the AUC on whether to proceed, and how to proceed, on these issues is expected in the second quarter of 2008.

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. The benchmarking report, dealing with the period of 2003-2007, was received on January 23, 2008. In February 2008 the benchmarking report along with an application to adjust the placeholder rates was filed with the AUC. In April 2008, an agreement with the customer group concerning the adjustment to placeholders was submitted to the AUC for approval. Should this agreement be approved by the AUC it is not expected to have a material impact on consolidated earnings. An AUC decision on the agreement is expected in the second quarter of 2008.

Effective January 1, 2008, price changes for ATCO I-Tek's information technology services to ATCO Electric, ATCO Gas and ATCO Pipelines were implemented. Price changes relating to ATCO I-Tek's customer care and billing contract services for ATCO Gas and ATCO Electric were effective March 1, 2008. For 2008 and beyond, a new regulatory process will be set up to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates.

Utility Asset Disposition Rate Review Proceeding

In March 2008, the AUC initiated a proceeding to consider the potential rate related implications for Alberta utilities of the Supreme Court of Canada's 2006 Calgary Stores Block Decision (Stores Block Decision). The Calgary Stores Block matter involved the disposition by ATCO Gas of its Calgary Stores Block facility and adjacent property in downtown Calgary. The Supreme Court held that utility shareholders were entitled to receive all proceeds resulting from the sale.

The AUC has indicated that the Stores Block Decision may have various implications with respect to regulation of Alberta utility companies. The AUC would like to develop a comprehensive understanding of these potential implications through this proceeding and then apply this understanding in a consistent manner in future decisions. At the conclusion of this proceeding, the AUC will issue a decision reflecting its conclusions with respect to the interpretation and application of the guidance provided by the courts and the resulting implications to be used in future proceedings.

ATCO Gas

Deferred Gas Account

ATCO Gas 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 City of Calgary filed a leave to appeal the AUC's decision. ATCO Gas filed a cross appeal of the AUC's decision. 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 of 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 January 3, 2008, the AUC issued a decision confirming its jurisdiction to approve the prior period adjustment it had approved previously. In February 2008, the City of Calgary filed a Leave to Appeal the January 3, 2008 decision with the Alberta Court of Appeal.

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's first quarter 2008 **revenues decreased** by \$7.1 million (3.4%) over the first quarter of 2007, primarily as a result of the impact of the Barking Outage. This decrease was 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 the recent changes in environmental laws (refer to Business Risks – Environmental Matters section).

Earnings for the three months ended March 31, 2008 were \$35.0 million, a **decrease** of \$8.4 million (19.4%) over the first quarter of 2007 including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings for the three months ended March 31, 2008, were \$34.7 million, a **decrease** of \$4.2 million (10.8%) over the first quarter of 2007, primarily due to lower earnings resulting from reduced availability at the Barking generating plant and the impact of lower U.K. exchange rates on conversion of earnings to Canadian dollars in ATCO Power's U.K. operations. These decreases were primarily offset by the recognition of insurance proceeds from the Barking Outage.

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

	For the Three Months Ended March 31		
	2008	2007	Change to 2008 (2008-2007)
ATCO Power			
Canada	98.6%	94.6%	4.0%
U.K. ⁽¹⁾	67.6%	97.9%	(30.3)%
Australia	99.9%	97.0%	2.9%
Alberta Power (2000)			
Canada	92.0%	94.9%	(2.9)%

Note:

⁽¹⁾ The lower availability in 2008 reflects the outage at the Barking generating plant which commenced on October 25, 2007. On March 6, 2008, ATCO Power announced that the plant had returned to service.

Unplanned Outage at Barking Generating 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. On March 6, 2008, ATCO Power announced that the plant had returned to service. This outage reduced the plant capacity to approximately 400 MWs during this period. The financial impact of the failure, prior to the recognition of insurance proceeds, was a decrease to ATCO Power's earnings of \$13.4 million, (\$8.6 million related to 2007 and \$4.8 million related to the three months ended March 31, 2008). During the three month period ended March 31, 2008, \$8.1 million of business interruption insurance proceeds were recorded, (\$3.3 million related to 2007 and \$4.8 million related to the three months ended March 31, 2008). ATCO Power was able to recognize these insurance proceeds as a result of the certainty supporting the allocation of the proceeds.

The financial impact of the failure, including the recognition of the insurance proceeds, was a decrease to ATCO Power's earnings of \$8.6 million in 2007 and increased earnings by \$3.3 million for the three months ended March 31, 2008.

Discussions are ongoing with insurers and their advisers to arrive at a final settlement. At this time, an amount for the final insurance settlement cannot be determined.

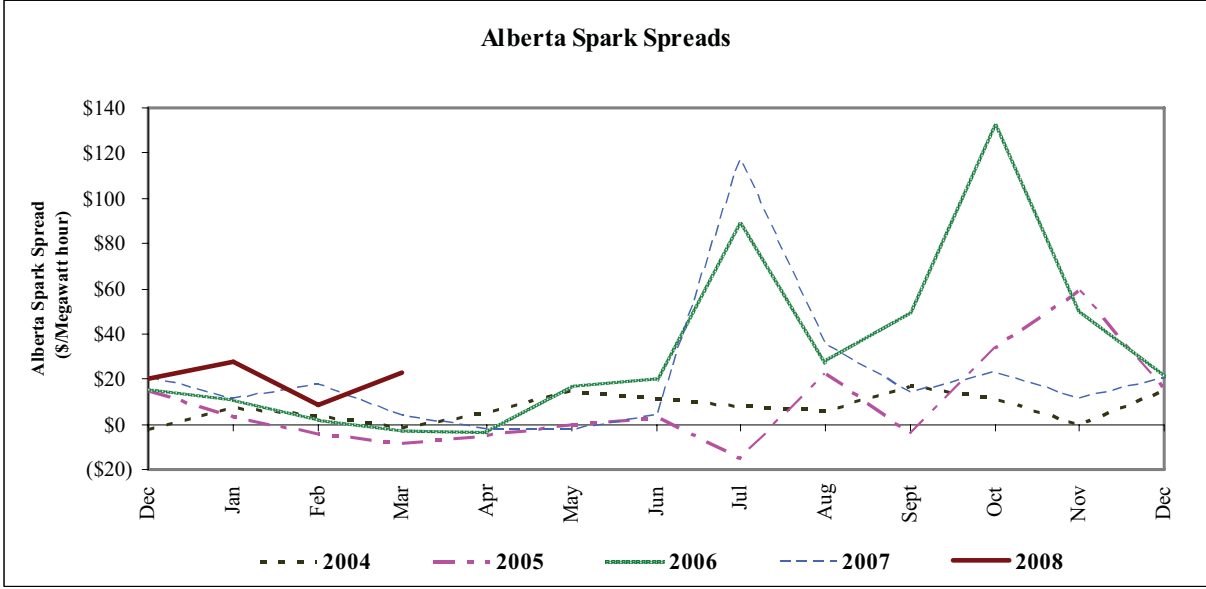
Other Power Generation Developments

On January 30, 2008, Unit 4 at Alberta Power (2000)'s 150 MW Battle River generating plant experienced an unplanned outage due to a failure in the unit's generator. The unit returned to service on March 27, 2008. Alberta Power (2000) has claimed relief under the force majeure provisions of its PPA. These provisions provide protection for the operator against mechanical failures which last more than forty-two days, except for circumstances where it is found that the operator failed to follow good operating practices. If the claim for relief is not successful, the cash impact will be approximately \$11.8 million. Due to the availability incentive pool deferral account, Alberta Power (2000) does not expect any material earnings impact as a result of this outage.

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 \$76.95 per MWh for the three months ended March 31, 2008, compared to average prices of \$63.29 per MWh in corresponding period of 2007. Natural gas prices averaged \$7.56 per GJ, compared to average prices of \$7.00 per GJ in the first quarter of 2007. These electricity and natural gas prices resulted in an average spark spread of \$20.23 per MWh for the three months ended March 31, 2008, up from \$10.76 per MWh in first three months of 2007.

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 spark spreads experienced by ATCO Power for the period of December 2003 to March 2008.



The Company’s merchant power sales are affected 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)

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.

During the three months ended March 31, 2008, the deferred availability incentive account increased by \$0.9 million to \$42.7 million, mainly due to incentives received in the first quarter due to good availability, partially offset by penalties paid for the Battle River generating plant forced outage. During the three months ended March 31, 2008, the amortization of deferred availability incentives, recorded in revenues, increased by \$0.1 million to \$3.0 million, compared to the corresponding period in 2007.

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 \$32.2 million (17.7%) for the three months ended March 31, 2008, as compared with the three months ended March 31, 2007. Items that increased revenues included increased international operations in ATCO Frontec and higher sales of natural gas on a no-margin basis for storage operations and higher prices and volumes of natural gas processed for NGL extraction in ATCO Midstream. These increases were partially offset by lower storage revenues due to the timing and demand of storage capacity sold and lower storage fees in ATCO Midstream.

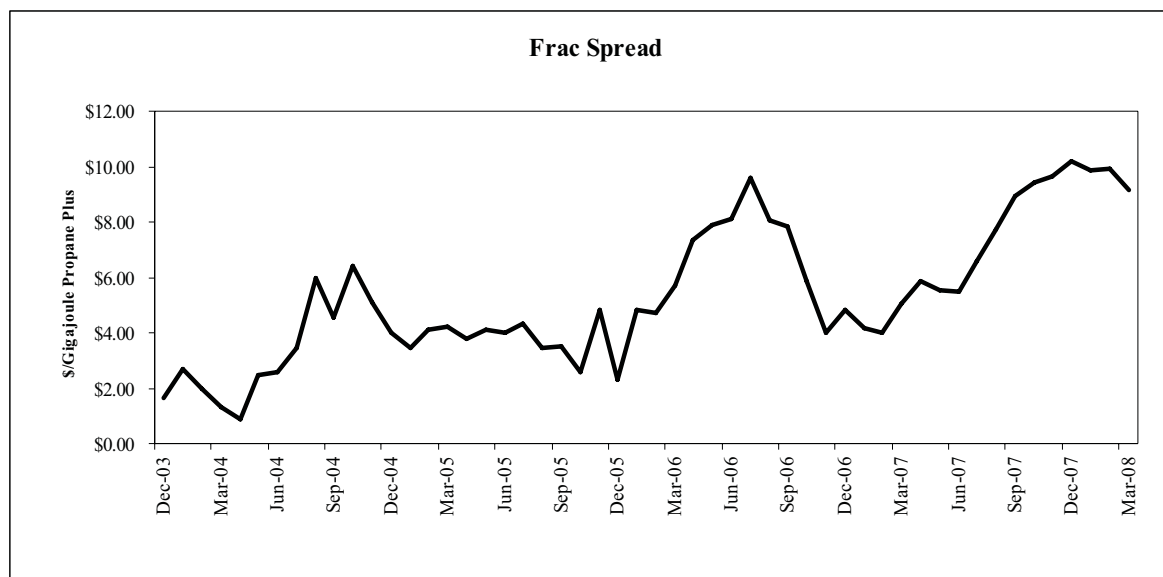
Earnings and Adjusted Earnings for the three months ended March 31, 2008 were \$48.9 million, an **increase** of \$6.1 million (14.3%) over the first quarter of 2007. The primary reasons for the higher earnings in the first quarter of 2008 were higher margins and prices for NGL extraction in ATCO Midstream and increased international operations in ATCO Frontec. These increases were partially offset by lower storage fees in ATCO Midstream.

ATCO Midstream

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 2003 to March 2008.



Note:

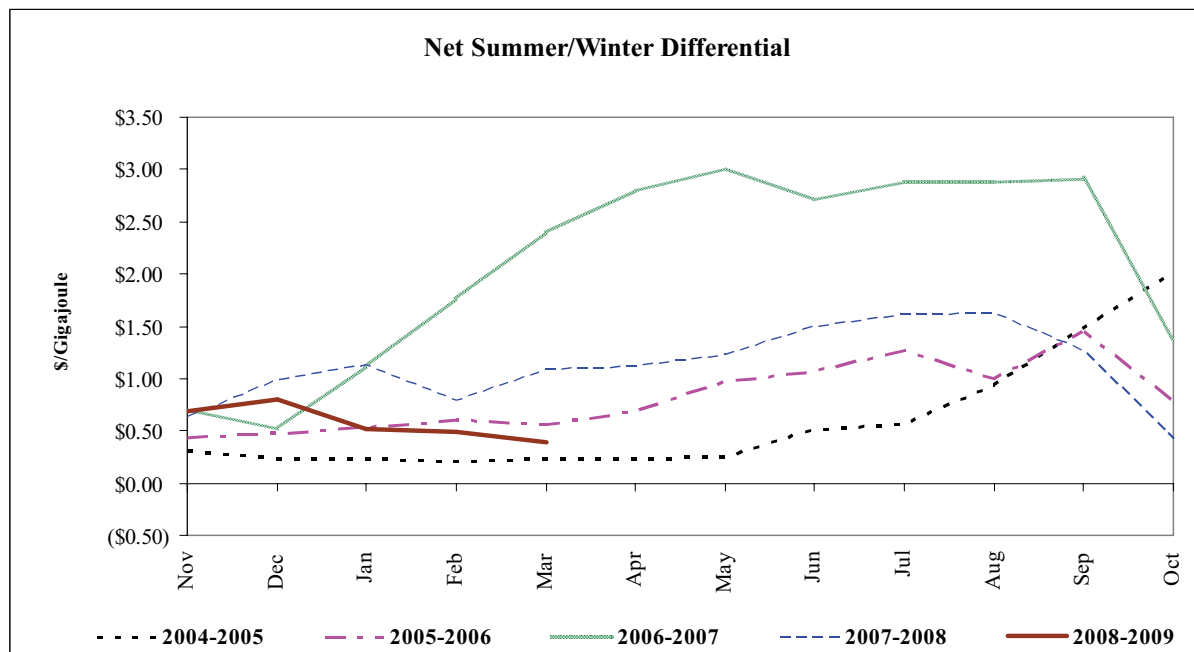
⁽¹⁾ The above chart represents measurements of frac spreads in Alberta, as reported by an independent consultant.

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 (price differentials). Recognition of ATCO Midstream's revenues is determined through the terms of the contractual arrangements.

Summer/winter natural gas price differentials can be volatile, as shown in the following graph, which illustrates a range of seasonal spreads experienced during the storage periods from 2004-2005 to 2008-2009. Price differentials at any point in time may not always be indicative of the storage revenue and earnings for the same period due to the types of contracts and the timing of the revenue recognition associated with these contracts.



ATCO Midstream faces risks associated with changes to seasonal natural gas commodity price differentials. To mitigate this risk, ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for its storage operations.

ATCO Frontec

Recent Developments

On April 14, 2008, ATCO Frontec announced that the first phase of the 500-room Creeburn Lake Lodge in Fort McMurray, Alberta had opened for operations. Due to the demand for lodging, evaluation is underway to consider doubling capacity to 1,000 rooms under the existing joint venture with the Fort McKay First Nation.

On April 28, 2008, ATCO Frontec and their partner, the Fort McKay First Nation, announced that they have been selected by Suncor Energy to create and operate a 1,148-room accommodation complex to support oil sands development north of Fort McMurray. ATCO Structures will supply the rooms in modular units. The complex is expected to open on May 25, 2008, and remain in place for a one-year period.

Corporate and Other

Earnings for the first quarter of 2008 were **substantially unchanged**.

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 its wholly owned subsidiary, CU Inc., 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 (\$ millions)	For the Three Months Ended March 31		
	2008	2007	Change to 2008 (2008-2007)
Cash position, beginning of period	747.2	798.8	(6.5)%
Cash provided by (used in)			
Operating activities	256.6	326.4	(21.4)%
Investing activities	(121.9)	(124.4)	(2.0)%
Financing activities	(70.8)	(61.8)	14.6%
Foreign currency impact on cash balances	1.7	(0.4)	525.0%
Cash position, end of period	812.8	938.6	(13.4)%

OPERATING ACTIVITIES

For the three months ended March 31, 2008, **cash flow from operations** was \$256.6 million, a **decrease** of \$69.8 million (21.4%) over the same period in 2007, primarily due to changes in non-cash working capital. **Funds generated by operations** was \$243.2 million, an **increase** of \$11.0 million (4.7%) over the first quarter of 2007, primarily due to higher earnings partially offset by decreased deferred availability incentives in Alberta Power (2000).

INVESTING ACTIVITIES

For the three months ended March 31, 2008, cash used in **investing activities decreased** 2.0%, primarily due to increased contributions by utility customers for extensions to plant, changes in non-cash working capital and changes in non-current deferred electricity costs. These decreases were partially offset by higher capital expenditures in 2008. Capital expenditures increased by \$60.8 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 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 segment. Capital expenditures for 2008 to 2010 are expected to be approximately \$3.0 billion for the Utilities segment.

FINANCING ACTIVITIES

In the first quarter of 2008, the Company had **net debt decreases** of \$32.5 million due to repayments of non-recourse long term debt.

There were **no purchases** of Canadian Utilities' Class A non-voting shares under the normal course issuer bid and **no issues** of Canadian Utilities Class A non-voting shares due to stock option exercises in the first quarter of 2008.

On May 23, 2006, the company 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, the company 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 April 25, 2008, 157,800 shares have been purchased all of which were purchased in 2007.

Total **dividends** for the three months ended March 31, 2008 **increased** by \$3.5 million (9.2%) to \$41.7 million over the same period in 2007. **Dividends paid to Class A and Class B share owners** for the three months ended March 31, 2008 increased by \$0.0275 to \$0.3325 per share. The Company has increased its annual common share dividend each year since its inception as a holding company in 1972. 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.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation for the three months ended March 31, 2008, positively impacted the Company's cash position by \$2.1 million over the same period in 2007, as a result of changes in U.K. and Australian exchange rates used for balance sheet translations.

SHORT TERM INVESTMENT POLICY

The Company has a long standing policy not to invest any of its cash balances in asset-backed securities, consequently, the recent turmoil in the asset-backed commercial paper market has had no impact on the Company.

LINES OF CREDIT

At March 31, 2008, 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	52.2	547.8
Uncommitted	74.0	20.5	53.5
Total	1,000.0	120.9	879.1

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

CONTRACTUAL OBLIGATIONS

Contractual obligations disclosed in the 2007 MD&A remain substantially unchanged as at March 31, 2008.

CURRENT AND LONG TERM FUTURE INCOME TAX LIABILITY

Current and long term future income tax liabilities of \$159.9 million at March 31, 2008, 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.

Share Capital

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

At April 25, 2008, the Company had outstanding 81,571,286 Class A shares, 43,723,384 Class B shares and options to purchase 1,445,700 Class A shares.

Business Risks

Information contained in the 2007 MD&A related to Business Risks which is not discussed in this section remains substantially unchanged.

ENVIRONMENTAL MATTERS

The Company's operating subsidiaries and the industries in which they operate are subject to extensive federal, provincial and local environmental protection laws concerning emissions to the air, discharges to surface and subsurface waters, land use activities and the handling, manufacturing, processing, use, emission and disposal of materials and waste products.

On March 10, 2008, the Government of Canada released details on its regulatory framework originally announced on April 26, 2007. Electricity sector companies must achieve an initial GHG reduction in 2010 of 18% from their company-wide emission intensity, with a 2% continuous improvement required annually thereafter. 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. For cogeneration facilities, steam production GHG emissions are subjected to the reduction target and electricity production emissions are compared to a deemed emission target. 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. The government reiterated that it still intends to transition to fixed emission caps in the 2020 to 2025 time period. Final regulations on GHG emissions are expected to be published in the fall of 2009.

The federal government also announced plans to set targets to regulate air pollutants (sulphur dioxide, nitrogen oxides, particulate matter, volatile organic compounds and mercury) from industrial sources by 2015. Amendments to the air pollutant section of the regulatory framework are expected in the spring of 2008.

Alberta legislation requires large emitters to reduce GHG emission intensities by 12% starting July 1, 2007. Baseline emission values for Alberta Power (2000)'s and ATCO Power's facilities have been established and compliance reports with payments for 2007 GHG obligations were submitted to Alberta Environment on March 31, 2008. For Alberta Power (2000)'s coal-fired units, the PPA counterparties provided payments for their 2007 GHG obligations.

Alberta regulation requires coal-fired generating plant operators, including Alberta Power (2000), to monitor mercury emissions and capture at least 70% of the mercury in coal emissions commencing January 1, 2011. A full scale test is planned for Unit 5 at the Battle River generating plant in 2008 to evaluate the mercury control method to ensure the capture objective can be met.

It is anticipated that the PPAs will allow Alberta Power (2000) to recover most of the costs associated with complying with both the Federal and Alberta regulations during the PPA term.

Due to lower emissions per unit of output, ATCO Power's gas-fired generating units have minimal exposure to changes in GHG regulations, and therefore it is anticipated that there will not be a material impact from complying with the Alberta regulations. ATCO Power is currently evaluating the impact of complying with the federal regulations.

REGULATED OPERATIONS

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.

Changes in Accounting Policies

Effective January 1, 2008, the Company adopted the Canadian Institute of Chartered Accountants (CICA) recommendations for capital disclosures which require disclosure of qualitative and quantitative information regarding the Company's objectives, policies and processes for managing capital (refer to Note 6 to the unaudited interim consolidated financial statements for the three months ended March 31, 2008). The recommendation requires additional disclosure in the notes to the financial statements.

Effective January 1, 2008, the Company adopted the CICA recommendations pertaining to disclosure and presentation of financial instruments which require disclosure of the classification of the Company's financial instruments and additional qualitative and quantitative information regarding the nature and extent of risks arising from financial instruments to which the Company is exposed (refer to Note 7 to the unaudited interim consolidated financial statements for the three months ended March 31, 2008). The recommendation requires additional disclosure in the notes to the financial statements.

Effective January 1, 2008, the Company prospectively adopted the CICA recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value, and on the cost formulas that are used to assign costs to inventories. The recommendations also clarified that major spare parts are to be included in property, plant and equipment. As a result of adopting these recommendations, the Company reclassified \$1.8 million of inventories to property, plant, and equipment related to major spare parts on January 1, 2008 (refer to Note 1 to the unaudited interim consolidated financial statements for the three months ended March 31, 2008).

FUTURE ACCOUNTING CHANGES

The CICA has issued new accounting recommendations for goodwill and intangible assets which establish standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets). These recommendations are effective for the Company beginning January 1, 2009. Goodwill and intangible assets that are not assets as defined by GAAP will be derecognized and charged to the equity of the Company at that date. The Company is evaluating the effect of these recommendations on its financial statements.

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.

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

	Note	Three Months Ended March 31	
		2008	2007
		<i>(Unaudited)</i>	
Revenues		\$ 740.6	\$ 697.6
Costs and expenses			
Natural gas supply		14.9	3.1
Purchased power		15.3	13.8
Operation and maintenance		244.5	240.6
Selling and administrative		51.9	42.4
Depreciation and amortization	1	90.1	91.9
Interest		46.4	42.6
Interest on non-recourse long term debt		9.5	12.0
Franchise fees		62.7	58.5
		535.3	504.9
		205.3	192.7
Interest and other income	7	14.0	20.2
Earnings before income taxes		219.3	212.9
Income taxes		61.2	69.4
		158.1	143.5
Dividends on equity preferred shares		8.1	8.8
Earnings attributable to Class A and Class B shares		150.0	134.7
Retained earnings at beginning of period		2,036.0	1,813.3
		2,186.0	1,948.0
Dividends on Class A and Class B shares		41.7	38.2
Retained earnings at end of period		\$2,144.3	\$1,909.8
Earnings per Class A and Class B share	5	\$ 1.20	\$ 1.07
Diluted earnings per Class A and Class B share	5	\$ 1.19	\$ 1.07
Dividends paid per Class A and Class B share	5	\$ 0.3325	\$ 0.305

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

		March 31		December 31
	Note	2008	2007	2007
		<i>(Unaudited)</i>		<i>(Audited)</i>
ASSETS				
Current assets				
Cash and short term investments		\$ 855.0	\$ 939.0	\$ 747.2
Accounts receivable		375.9	311.4	373.9
Inventories	1, 3	95.8	94.4	101.8
Regulatory assets		22.1	8.3	10.2
Derivative assets	7	0.1	0.1	0.8
Prepaid expenses		24.2	22.3	29.8
		1,373.1	1,375.5	1,263.7
Property, plant and equipment		5,748.2	5,441.9	5,678.5
Regulatory assets		66.3	44.6	75.6
Derivative assets	7	72.6	82.2	73.3
Other assets		196.3	201.1	194.3
		\$7,456.5	\$7,145.3	\$7,285.4
LIABILITIES AND SHARE OWNERS' EQUITY				
Current liabilities				
Bank indebtedness	4	\$ 42.2	\$ 0.4	\$ -
Accounts payable and accrued liabilities		369.9	343.0	375.0
Income taxes payable		26.7	34.6	1.2
Future income taxes		0.3	0.3	1.7
Regulatory liabilities		7.5	4.8	-
Derivative liabilities	7	2.9	2.1	2.6
Non-recourse long term debt due within one year		45.3	66.0	65.4
		494.8	451.2	445.9
Future income taxes		159.6	199.4	153.8
Regulatory liabilities		141.3	144.2	146.5
Derivative liabilities	7	6.3	4.6	3.3
Deferred credits	7	314.8	299.2	307.9
Long term debt		2,603.4	2,399.0	2,603.2
Non-recourse long term debt		470.0	586.8	478.1
Equity preferred shares		625.0	636.5	625.0
Class A and Class B share owners' equity				
Class A and Class B shares	5	516.9	516.6	516.9
Contributed surplus		2.1	1.4	1.9
Retained earnings		2,144.3	1,909.8	2,036.0
Accumulated other comprehensive income		(22.0)	(3.4)	(33.1)
Retained earnings and accumulated other comprehensive income		2,122.3	1,906.4	2,002.9
		2,641.3	2,424.4	2,521.7
		\$7,456.5	\$7,145.3	\$7,285.4

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

	Note	Three Months Ended March 31	
		2008	2007
		<i>(Unaudited)</i>	
Operating activities			
Earnings attributable to Class A and Class B shares		\$ 150.0	\$ 134.7
Adjustments for:			
Depreciation and amortization	1	90.1	91.9
Future income taxes		2.0	2.7
Deferred availability incentives		0.9	6.6
TXU Europe settlement - net of income taxes		(2.5)	(3.0)
Other		2.7	(0.7)
Funds generated by operations		243.2	232.2
Changes in non-cash working capital		13.4	94.2
Cash flow from operations		256.6	326.4
Investing activities			
Purchase of property, plant and equipment		(184.5)	(123.7)
Costs on disposal of property, plant and equipment		(0.9)	(0.5)
Contributions by utility customers for extensions to plant		48.7	19.8
Non-current deferred electricity costs		6.9	(1.4)
Changes in non-cash working capital		9.9	(14.2)
Other		(2.0)	(4.4)
		(121.9)	(124.4)
Financing activities			
Repayment of non-recourse long term debt		(32.5)	(25.1)
Net issue of Class A shares		-	0.5
Dividends paid to Class A and Class B share owners		(41.7)	(38.2)
Changes in non-cash working capital		0.1	-
Other		3.3	1.0
		(70.8)	(61.8)
Foreign currency translation		1.7	(0.4)
Cash position ⁽¹⁾			
Increase		65.6	139.8
Beginning of period		747.2	798.8
End of period		\$ 812.8	\$ 938.6

⁽¹⁾ Cash position consists of cash and short term investments less current bank indebtedness, and includes \$122.1 million (2007 - \$204.4 million) which is only available for use in joint ventures.

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

	Three Months Ended March 31	
	2008	2007
	<i>(Unaudited)</i>	
Earnings attributable to Class A and Class B shares	\$150.0	\$134.7
Other comprehensive income, net of income taxes:		
Cash flow hedges	(3.8)	0.5
Foreign currency translation adjustment	14.9	0.3
Comprehensive income	\$161.1	\$135.5

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2008
(Unaudited, Tabular Amounts in Millions of Canadian Dollars)

1. Summary of significant accounting policies

Financial statement presentation

The accompanying consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and should be read in conjunction with consolidated financial statements and related notes included in the Corporation’s Financial Information contained in its 2007 Annual Report. These interim financial statements have been prepared using the same accounting policies as used in the financial statements for the year ended December 31, 2007, except as described below.

Effective January 1, 2008, the Corporation adopted the Canadian Institute of Chartered Accountants (“CICA”) recommendations for capital disclosures which require disclosure of qualitative and quantitative information regarding the Corporation’s objectives, policies and processes for managing capital (see Note 6).

Effective January 1, 2008, the Corporation adopted the CICA recommendations pertaining to disclosure and presentation of financial instruments which require disclosure of the classification of the Corporation’s financial instruments (as described in the Financial Instruments section below) and additional qualitative and quantitative information regarding the nature and extent of risks arising from financial instruments to which the Corporation is exposed (see Note 7).

Effective January 1, 2008, the Corporation prospectively adopted the CICA recommendations for measurement and disclosure of inventories which provide guidance on the determination of cost and its subsequent recognition as an expense, including any write-down to net realizable value, and on the cost formulas that are used to assign costs to inventories. The recommendations also clarified that major spare parts are to be included in property, plant and equipment. As a result of adopting these recommendations, the Corporation reclassified \$1.8 million of inventories to property, plant, and equipment related to major spare parts on January 1, 2008.

Due to the seasonal nature of the Corporation’s operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in natural gas liquids prices and natural gas costs and the timing of rate decisions, the consolidated statements of earnings, retained earnings and comprehensive income for the three months ended March 31, 2008 and March 31, 2007 are not necessarily indicative of operations on an annual basis.

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

Inventories

Inventories are valued at the lower of cost or net realizable value. The cost of inventories is assigned using the weighted average cost method. Net realizable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

The cost of inventories is comprised of all costs of purchase, costs of conversion and other costs to bring the inventories to their present condition and location. The costs of purchase comprise the purchase price, import duties and non-recoverable taxes, and transport, handling and other costs directly attributable to the acquisition of finished goods, materials or services. The costs of conversion include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

Property, Plant and Equipment

Effective January 1, 2008, ATCO Gas prospectively changed the allocation of annual depreciation and amortization expense on a quarterly basis. The method of quarterly allocation has been changed from an estimate based on the timing of revenues to the straight line basis. The annual depreciation and amortization expense continues to be on the straight line basis and, therefore, this change does not affect the total depreciation and amortization expense

1. Summary of significant accounting policies (continued)

recognized for the year. This change in allocation resulted in an increase to consolidated earnings after income taxes of \$4.9 million for the three months ended March 31, 2008.

Financial Instruments

The Corporation establishes the classification of financial instruments at their initial recognition. Financial assets are classified as held for trading, available for sale, held to maturity or loans and receivables. Financial liabilities are classified as held for trading or other liabilities.

Financial instruments classified as held for trading, other than derivative instruments that are effective hedging instruments, are measured at fair value with changes in fair value recognized in earnings. Derivatives that are designated as, and continue to be, effective cash flow hedging instruments have gains and losses in fair values recognized through other comprehensive income. Derivatives that are designated as fair value hedging instruments have gains and losses recognized in earnings.

Financial instruments classified as available for sale are measured at fair value using quoted prices in an active market. Changes in fair value are recognized in other comprehensive income until the item is derecognized or determined to be impaired, at which time the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. When actively quoted prices are not available, fair value is determined using other valuation techniques. If fair value cannot be reliably estimated, the item is carried at cost.

Financial instruments classified as held to maturity, loans and receivable or other liabilities are measured at fair value upon initial recognition but are subsequently measured at their amortized cost using the effective interest method.

Future Accounting Changes

The following new accounting recommendations are in addition to those future accounting changes disclosed in the December 31, 2007 consolidated financial statements.

The CICA has issued new accounting recommendations for goodwill and intangible assets which establish standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets). These recommendations are effective for the Corporation beginning January 1, 2009. Goodwill and intangible assets that are not assets as defined by GAAP will be derecognized and charged to the equity of the Corporation at that date. The Corporation is evaluating the effect of these recommendations on its financial statements.

2. Regulatory matters

In September 2007, ATCO Electric received a decision on its General Tariff Application for 2007 and 2008 which approved a return on common equity of 8.75% for 2008 and 8.51% for 2007. ATCO Gas' and ATCO Pipelines' General Rate Applications for 2008 and 2009 contain placeholder returns on common equity of 8.75% for 2008. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year.

A process continues with respect to the pricing of services provided by ATCO I-Tek to the utilities. A benchmarking report was received in January 2008 and filed with the Alberta Utilities Commission ("AUC") in February 2008, along with an application to adjust placeholders. In April 2008 an agreement with the customer group concerning the adjustment to placeholders was submitted to the AUC for approval. Should this agreement be approved by the AUC, it is not expected to have a material impact on consolidated earnings. A decision from the AUC is expected before the end of the second quarter of 2008.

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

3. Inventories

	March 31	
	2008	2007
Natural gas and fuel in storage	\$34.4	\$38.2
Raw materials and consumables	61.4	56.2
	\$95.8	\$94.4

For the three months ended March 31, 2008, the amount of inventories recognized as an expense was \$26.9 million (2007 – \$26.4 million), there have been no write-downs to net realizable value and there have been \$0.6 million reversals of previous write-downs to net realizable value.

Inventories in the amount of \$11.1 million are pledged as security for liabilities.

4. Bank indebtedness

During the three months ended March 31, 2008, the Corporation borrowed \$42.2 million on its short term committed line of credit. The borrowing is repayable in Euros at an interest rate of 5.03% and is unsecured.

5. Class A and Class B shares

There were 81,559,886 (2007 – 81,486,886) Class A non-voting shares and 43,734,784 (2007 – 43,922,484) Class B common shares outstanding on March 31, 2008. In addition, there were 1,445,700 options to purchase Class A non-voting shares outstanding at March 31, 2008 under the Corporation's stock option plan. From April 1, 2008, to April 25, 2008, no stock options were granted or cancelled, no stock options were exercised, 11,400 Class B common shares were exchanged for Class A non-voting shares and no Class A non-voting shares were purchased under the Corporation's normal course issuer bid.

The average number of shares used to calculate earnings per share are as follows:

	Three Months Ended March 31	
	2008	2007
Weighted average shares outstanding	125,294,670	125,390,433
Effect of dilutive stock options	517,799	499,458
Weighted average diluted shares outstanding	125,812,469	125,889,891

6. Capital disclosures

The Corporation's objectives when managing capital are:

1. to safeguard the ability to continue as a going concern, so that it can continue to provide returns to share owners and benefits for other stakeholders;
2. to maintain an appropriate credit rating in order to provide efficient and cost effective access to funds required for operations and growth; and
3. to remain within the capital structure approved by the AUC.

The Corporation includes share owners' equity, equity preferred shares, long term debt and non-recourse long term debt in its determination of capitalization. In managing its capital, the Corporation considers both the regulated and non-regulated operations in the consolidated group as well as changes in economic conditions and risks impacting the core assets and operations. In maintaining or adjusting its capital structure, the Corporation may adjust the amount of dividends paid to share owners, issue or purchase Class A and Class B shares, and issue or redeem equity preferred shares, long term debt and non-recourse long term debt.

6. Capital disclosures (continued)

The Corporation's utility operations are regulated primarily by the AUC, which, through the generic cost of capital decision issued in 2004, established the capital structure for each utility. The utility operations are, therefore, capitalized consistent with the generic cost of capital decision. The capitalization involves the use of long term debt and preferred share financings; the AUC approved the continued use of the latter in a decision issued in 2006.

While the Corporation's utility operations are capitalized consistent with the AUC decisions, the Corporation itself is not restricted in its capital structure. The capital structure for the Corporation is set relative to risk and to meet the financial and operational objectives of the Corporation (while considering the decisions of the regulator).

Decisions on the level and type of financing are based on assessments by management in line with the Corporation's objectives. In determining the type of financing to be undertaken by a given operation, the Corporation has a goal of managing the financial risk to the Corporation as a whole.

Capital is monitored through an equity capitalization measure which is calculated as total equity divided by total capitalization. Total equity is comprised of Class A and Class B shares, contributed surplus, retained earnings, accumulated other comprehensive income and equity preferred shares. Total capitalization is comprised of long term debt, non-recourse long term debt and total equity. The Corporation's strategy, which is unchanged from 2007, is to maintain the equity capitalization allowed by the regulator for the regulated operations and to structure the non-regulated operations so as to sustain access to cost effective financing by maintaining high credit ratings on debt and preferred shares. The Corporation looks to maintain an equity capitalization in the range of 45% to 55%.

Other measures that are taken into consideration are interest coverage and interest and preferred dividend coverage. Interest coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by total interest expense. Interest and preferred dividend coverage is calculated by dividing earnings before income taxes, interest expense and dividends on equity preferred shares by interest expense and dividends on equity preferred shares (grossed up to pre-tax equivalents). The Corporation looks to maintain interest coverage of at least 2.5 and interest and preferred dividend coverage of at least 2.0; these objectives are unchanged from 2007.

Equity capitalization, interest coverage and interest and preferred dividend coverage do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

The Corporation's key measures of capital structure are as follows:

	March 31	
	2008	2007
Class A and Class B shares	\$ 516.9	\$ 516.6
Contributed surplus	2.1	1.4
Retained earnings	2,144.3	1,909.8
Accumulated other comprehensive income	(22.0)	(3.4)
Equity preferred shares	625.0	636.5
Total equity	3,266.3	3,060.9
Long term debt	2,603.4	2,399.0
Non-recourse long term debt	470.0	586.8
Total debt	3,073.4	2,985.8
Total capitalization	\$6,339.7	\$6,046.7
Equity capitalization	52%	51%

The equity capitalization is consistent with the Corporation's objectives. Total equity increased primarily due to higher earnings of the Corporation reflected in increased retained earnings. Total debt increased primarily due to financings for utility capital expenditures partially offset by redemptions of non-recourse long term debt, including a one-time payment of \$52.7 million in the second quarter of 2007 which represented the Corporation's share of the TXU Europe settlement that was applied to Barking Power's non-recourse long term debt.

6. Capital disclosures (continued)

Interest coverage and interest and preferred dividend coverage are managed on an annual basis by the Corporation. Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in natural gas liquids prices and natural gas costs and the timing of rate decisions, revenues and earnings for any quarter are not necessarily indicative of operations on an annual basis. Therefore, quarterly coverage ratios are not presented as they are not necessarily indicative of the annual performance. The amounts presented below are the most recent annual coverage ratios:

	December 31 2007
Interest coverage ⁽¹⁾	3.3
Interest and preferred dividend coverage ⁽¹⁾	2.7

⁽¹⁾ *The coverage ratios for 2007 were negatively impacted by the AUC decision that directed ATCO Electric to refund future income taxes to customers. The total reduction in revenues and income taxes recorded in 2007 was \$39.6 million. If the reduction in revenues had not occurred, interest coverage would have been 3.5 and interest and preferred dividend coverage would have been 2.8.*

For the three months ended March 31, 2008, the Corporation was in compliance with externally imposed requirements on its capital (including debt covenants). The Corporation has a number of regulatory filings and regulatory hearing submissions before the AUC for which decisions have not been received, the outcome of which could affect the capital structure of the Corporation.

7. Risk management and financial instruments

The Corporation's Board of Directors ("Board") is responsible for understanding the principal risks of the business in which the Corporation is engaged, achieving a proper balance between risks incurred and the potential return to share owners, and confirming that there are systems in place that effectively monitor and manage those risks with a view to the long-term viability of the Corporation. The Board has established a Risk Review Committee, which reviews significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Corporation's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

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

At March 31, 2008 and March 31, 2007, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows associated with a portion of non-recourse long term debt, foreign currency forward contracts that hedge foreign currency risk on the future cash flows associated with specific firm commitments or anticipated transactions and certain natural gas purchase contracts.

7. Risk management and financial instruments (continued)

The derivative assets and liabilities comprise the following:

	March 31	
	2008	2007
<i>Derivative assets – current:</i>		
Interest rate swap agreements	\$ 0.1	\$ 0.1
<i>Derivative assets – non-current:</i>		
Natural gas purchase contracts	\$71.9	\$81.9
Interest rate swap agreements	0.7	0.3
	\$72.6	\$82.2
<i>Derivative liabilities – current:</i>		
Interest rate swap agreements	\$ 2.9	\$ 1.9
Foreign currency forward contracts	-	0.2
	\$ 2.9	\$ 2.1
<i>Derivative liabilities – non-current:</i>		
Interest rate swap agreements	\$ 6.3	\$ 4.6

Interest rate risk

The Corporation's interest-bearing assets and liabilities include cash and short-term investments, long term debt and non-recourse long term debt. The interest rate risk faced by the Corporation is largely a result of its non-recourse long term debt at variable rates and cash and short term investments. The Corporation has converted variable rate non-recourse long term debt to fixed rate debt through the following interest rate swap agreements:

Project Financing	Swap Fixed Interest Rate ⁽¹⁾	Variable Debt Interest Rate	Maturity Date	Notional Principal	
				2008	2007
Osborne: (\$30.3 million AUD (2007 – \$34.6 million AUD))	7.343%	Bank Bill Rate in Australia	December 2013	\$ 28.5	\$ 32.4
APALP:	7.790%	90 day BA	November 2008	1.3	2.6
	7.567%	90 day BA	December 2008	1.8	3.6
	7.750%	6 month LIBOR	December 2011	73.7	83.9
Joffre:	7.536%	90 day BA	September 2012	18.7	22.8
Scotford:	5.332%	90 day BA	September 2008	51.4	52.9
Muskeg River:	5.287%	90 day BA	December 2007	-	39.9
	5.515%	90 day BA	December 2012	28.7	-
	5.615%	3 month LIBOR	December 2012	7.2	-
Brighton Beach:	5.867%	30 day BA	June 2009	8.4	8.8
	6.605%	90 day BA	March 2019	33.7	35.6
Cory:	6.586%	90 day BA	June 2011	1.9	2.6
				\$255.3	\$285.1

BA – Bankers' Acceptance

LIBOR – London Interbank Offered Rate

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

7. Risk management and financial instruments (continued)

The Corporation has fixed interest rates, either directly or through interest rate swap agreements, on 98% (2007 – 96%) of total long term debt and non-recourse long term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, as a result of changes in market interest rates is limited. Interest rate swaps are designated as cash flow hedges; changes in the fair value of highly effective cash flow hedges, which include all but the Joffre interest rate swap, are recorded in other comprehensive income. Changes in the fair value of the Joffre interest rate swap are recorded in earnings and are not material.

The Corporation's cash and short term investments include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. Therefore, the Corporation has exposure to interest rate movements that occur beyond the term of maturity of the fixed rate investments.

Foreign currency exchange rate risk

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

Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency. The Corporation has entered into foreign currency forward contracts in order to fix the exchange rate on certain service contracts, planned equipment expenditures and operational cash flows denominated in U.K. pounds sterling (“£”), U.S. dollars and Euros. At March 31, 2008, the contracts consist of purchases of \$0.5 million U.S. (2007 – purchases of \$1.4 million U.S. and sales of 2.0 million Euros).

Natural gas purchase contracts and associated power generation revenue contract liability

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

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation could not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Corporation has recognized a provision for a power generation revenue contract and records 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.

Interest and other income for the three months ended March 31, 2008 includes a loss of \$0.6 million (2007 – gain of \$22.9 million) related to the change in fair value of the natural gas purchase contracts derivative asset. This loss is offset by a gain of \$1.0 million (2007 – loss of \$16.5 million) related to the change in fair value of the associated power generation revenue contract liability. The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability increased earnings by \$0.3 million, net of income taxes, for the three months ended March 31, 2008 (2007 – increase of \$4.5 million). At March 31, 2008, the natural gas purchase contracts derivative asset is \$71.9 million (2007 – \$81.9 million) and the power generation revenue contract liability is \$53.2 million (2007 – \$61.3 million).

7. Risk management and financial instruments (continued)

Credit risk

For cash and short term investments and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Cash and short term investments credit risk is reduced by investing in instruments issued by credit worthy financial institutions and in federal government issued short term instruments. Accounts receivable credit risk is reduced by a large and diversified customer base, requirement of letters of credit, and, for regulated operations other than Alberta Power (2000), the ability to recover an estimate for doubtful accounts through approved customer rates.

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. Derivative credit risk is minimized by dealing with large, credit-worthy counterparties in accordance with established credit approval policies.

The maximum exposure to credit risk is the carrying value of loans and receivables on the balance sheet. The Corporation does not have a concentration of credit risk with any counterparties. A significant portion of loans and receivables arise from the Corporation's operations in Alberta.

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. At March 31, 2008, the provision for impairment of credit losses was \$1.7 million. The changes in the provision for impairment were as follows:

	2008
Provision at beginning of period	\$1.5
Impairment of receivables	0.2
Provision at end of period	\$1.7

At March 31, 2008, the aging analysis of trade receivables that are past due but not impaired is as follows:

	2008
30 to 90 days	\$17.1
Greater than 90 days	4.6
	\$21.7

No other impairments have been identified within accounts receivable.

Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet its obligations associated with financial liabilities. Funds generated by operations provide a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term debt, non-recourse long term debt and preferred shares. Commercial paper borrowings and short term bank loans are used under available credit lines to provide flexibility in the timing and amounts of long term financing. The Corporation has a policy not to invest any of its cash balances in asset backed securities; consequently, the recent turmoil in the asset-backed commercial paper market has had no impact on the Corporation.

Contractual obligations have not changed substantially from those disclosed in the Corporation's December 31, 2007 consolidated financial statements.

7. Risk management and financial instruments (continued)

Fair value of non-derivative financial instruments

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

	March 31			
	2008		2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
<i>Financial Assets</i>				
<i>Held For Trading:</i>				
Cash ⁽¹⁾	\$ 220.8	\$ 220.8	\$ 245.4	\$ 245.4
<i>Held to Maturity:</i>				
Short term investments ⁽¹⁾	634.2	634.2	693.6	693.6
<i>Loans and Receivables:</i>				
Accounts receivable ⁽¹⁾	375.9	375.9	311.4	311.4
<i>Financial Liabilities</i>				
<i>Held For Trading:</i>				
Bank indebtedness ⁽²⁾	42.2	42.2	0.4	0.4
<i>Other Liabilities:</i>				
Accounts payable and accrued liabilities ⁽²⁾	369.9	369.9	343.0	343.0
Long term debt ⁽³⁾	2,603.4	2,925.0	2,399.0	2,773.8
Non-recourse long term debt ⁽³⁾	515.3	554.1	652.8	691.1

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

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

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

7. Risk management and financial instruments (continued)

Fair value of derivative financial instruments

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

	March 31					
	2008			2007		
	Notional Principal ⁽¹⁾	Fair Value Receivable (Payable) ⁽³⁾	Maturity	Notional Principal ⁽¹⁾	Fair Value Receivable (Payable) ⁽³⁾	Maturity
<i>Held For Trading:</i>						
Interest rate swaps	\$255.3	\$(8.4)	2008-2019	\$285.1	\$(6.1)	2007-2019
Foreign currency forward contracts	\$ 0.5	Nil	2008-2009	\$ 4.6	\$(0.2)	2007
Natural gas purchase contracts	N/A ⁽²⁾	\$71.9	2014	N/A ⁽²⁾	\$81.9	2014

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

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

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

Sensitivity analysis

The analysis below illustrates the extent to which the Corporation's results are impacted by financial instruments and the underlying market risks (interest rate risk, foreign currency exchange risk, and commodity price risk). Non-derivative financial instruments (listed on the previous page) are recorded at cost and are not affected by changes in market variables whereas derivative financial instruments are affected by market variables.

The following table reflects the sensitivity in the fair value of outstanding derivative instruments to reasonably possible changes in Canadian and Australian interest rates, the foreign currency exchange rates of the Canadian dollar to the U.S. dollar and the forward price of natural gas. The analysis excludes the impact that changes in the underlying market risks would have on non-financial assets and liabilities, foreign currency translation of self-sustaining foreign operations included in accumulated other comprehensive income, and carrying value of employee future benefits. Sensitivities are reflected in changes to earnings and other comprehensive income, after income taxes.

Assumptions made in arriving at the sensitivity analysis are as follows:

- Changes in the fair value of derivative instruments that are effective cash flow hedges from movements in interest rates or foreign currency exchange rates are recorded in other comprehensive income.
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Balance sheet sensitivity to interest rates and foreign currency exchange rates relates only to derivative instruments. There are no available for sale financial assets and other liabilities are carried at amortized cost, in which case the carrying values are not affected by changes in interest rates and foreign currency exchange rates.
- Changes in the forward price of natural gas affect the mark to market adjustment of the natural gas purchase contracts derivative asset and the corresponding adjustment for the associated power generation revenue contract liability.

7. Risk management and financial instruments (continued)

	Three Months Ended March 31 2008	
	Earnings	Other Comprehensive Income
Canadian interest rates		
25 basis points increase	\$ 0.1	\$ 0.8
25 basis points decrease	\$(0.1)	\$(0.8)
Australian interest rates		
25 basis points increase	\$ -	\$ 0.1
25 basis points decrease	\$ -	\$(0.1)
U.S. dollar exchange rate		
10% increase	\$ 2.9	\$ -
10% decrease	\$(2.9)	\$ -
Forward price of natural gas		
10% increase	\$ 2.9	\$ -
10% decrease	\$(2.9)	\$ -

8. Employee future benefits

In the three months ended March 31, 2008, net expense of \$2.9 million (2007 – \$3.6 million) was recognized for pension benefit plans and net expense of \$1.3 million (2007 – \$1.3 million) was recognized for other post employment benefit plans.

9. Segmented information

Segmented results – Three months ended March 31

2008	Utilities	Power Generation	Global Enterprises	Corporate and Other	Intersegment Eliminations	Consolidated
2007						
<i>(Unaudited)</i>						
Revenues – external	\$ 363.2	\$ 198.8	\$178.2	\$ 0.4	\$ -	\$ 740.6
	\$ 338.4	\$ 205.9	\$152.9	\$ 0.4	\$ -	\$ 697.6
Revenues – intersegment ⁽¹⁾	6.3	-	35.9	2.8	(45.0)	-
	6.3	-	29.0	2.9	(38.2)	-
Revenues	\$ 369.5	\$ 198.8	\$214.1	\$ 3.2	\$ (45.0)	\$ 740.6
	\$ 344.7	\$ 205.9	\$181.9	\$ 3.3	\$ (38.2)	\$ 697.6
Earnings attributable to	\$ 66.5	\$ 35.0	\$ 48.9	\$ (0.1)	\$ (0.3)	\$ 150.0
Class A and Class B shares	\$ 49.1	\$ 43.4	\$ 42.8	\$ 0.2	\$ (0.8)	\$ 134.7
Total assets	\$4,223.9	\$2,207.0	\$363.1	\$641.2	\$ 21.3	\$7,456.5
	\$3,820.5	\$2,311.4	\$240.4	\$679.3	\$ 93.7	\$7,145.3

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

Printed in Canada