



**CANADIAN UTILITIES LIMITED**  
An **ATCO** Company

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

**FOR THE YEAR ENDED  
DECEMBER 31, 2006**

## Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A")

For The Year Ended December 31, 2006

The following discussion and analysis of financial condition and results of operations of Canadian Utilities Limited (the "Corporation") should be read in conjunction with the Corporation's unaudited consolidated interim financial statements for the three months ended December 31, 2006, and the audited consolidated financial statements for the year ended December 31, 2006. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at [www.sedar.com](http://www.sedar.com).

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

The equity securities of the Corporation consist of Class A non-voting shares ("Class A shares") and Class B common shares ("Class B shares").

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## FORWARD-LOOKING INFORMATION

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

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

## NON-GAAP FINANCIAL MEASURES

In this MD&A, reference is made to funds generated by operations, which is a measure that does not have a standardized meaning under Canadian Generally Accepted Accounting Principles (“GAAP”). Funds generated by operations is calculated on the Corporation’s consolidated statement of cash flows from operating activities before changes in non-cash working capital. In the Corporation’s opinion, funds generated by operations is a significant performance indicator of the Corporation’s ability to generate cash flow to fund its capital expenditures.

## CONTROLS AND PROCEDURES

### Disclosure Controls and Procedures

As of December 31, 2006, the Corporation’s management evaluated the effectiveness of the design and operation of its disclosure controls and procedures (“Disclosure Controls”) as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (“CEO”) and the Chief Financial Officer (“CFO”).

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

The Corporation’s management, including the CEO and the CFO, does not expect that the Corporation’s Disclosure Controls will prevent or detect all error and all fraud. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues and instances of fraud or error, if any, within the Corporation have been detected.

Based on the evaluation of Disclosure Controls, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Corporation’s Disclosure Controls are effective in providing reasonable assurance that material information relating to the Corporation and its consolidated subsidiaries is made known to the Corporation’s management.

## Internal Control Over Financial Reporting

As of December 31, 2006, management of the Corporation is responsible for evaluating the design of internal control over financial reporting ("Internal Control Over Financial Reporting"), as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO. The Corporation's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

There were no changes in the Corporation's internal controls over financial reporting that have occurred during the three months ended December 31, 2006, that have materially affected, or are reasonably likely to materially affect, the Corporation's internal control over financial reporting.

## BUSINESS OF THE CORPORATION

The Corporation's financial statements are consolidated from three Business Groups: Utilities, Power Generation and Global Enterprises. For the purposes of financial disclosure, corporate transactions are accounted for as Corporate and Other (refer to Note 23 to the consolidated financial statements for the year ended December 31, 2006). Transactions between Business Groups are eliminated in all reporting of the Corporation's consolidated financial information.

In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation. On August 1, 2006, the Corporation sold its 50% equity interest in Genics Inc., which was part of the Global Enterprises Business Group.

## STRATEGIC ALTERNATIVES FOR MIDSTREAM ASSETS

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

## TXU EUROPE SETTLEMENT

On November 19, 2002, an administration order was issued by an English Court against TXU Europe Energy Trading Limited ("TXU Europe") for breach of its contract to purchase 27.5% of the power produced by the 1,000 megawatt Barking generating plant, in which the Corporation owns a 25.5% equity interest. In 2005, the Corporation received \$83.1 million as its share of the partial settlement of the claim for damages related to TXU Europe's breach of this contract. An additional payment of \$16.6 million was received on January 19, 2006 and a final installment of approximately \$1.6 million was received on July 20, 2006. The settlement is expected to generate earnings after income taxes of approximately \$69 million, based on foreign currency exchange rates in effect on March 30, 2005, which will be recognized over the remaining term of the TXU Europe contract from October 1, 2004, to September 30, 2010, at approximately \$11 million per year. These earnings will be dependent upon the foreign currency exchange rates in effect at the time the earnings are recognized. For a description of the settlement, refer to Note 5 to the consolidated financial statements for the year ended December 31, 2006.

## H.R. MILNER INCOME TAX REASSESSMENT

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

## RECENT CHANGES IN INCOME TAXES AND RATES

Federal and provincial governments have recently announced a number of changes to income taxes and rates. As these changes are considered to have been substantively enacted, the Corporation made an adjustment to income taxes amounting to \$11.8 million in the second quarter of 2006, most of which relates to future income taxes. The adjustment increased 2006 earnings by \$11.8 million, of which \$1.9 million relates to the Utilities Business Group, \$7.2 million to the Power Generation Business Group, \$2.3 million to the Global Enterprises Business Group and \$0.4 million to Corporate and Other.

## SELECTED ANNUAL AND QUARTERLY INFORMATION

(\$ Millions except per share data)	For the Three Months Ended				Year
	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Ended Dec. 31
	<i>(unaudited)</i>				
2006 (1) (2)					
Revenues (3) (4) .....	642.0	563.4	553.9	671.1	2,430.4
Earnings attributable to Class A and Class B shares (4) .....	86.9	70.2	66.8	100.0	323.9
Earnings per Class A and Class B share .....	0.68	0.56	0.53	0.80	2.57
Diluted earnings per Class A and Class B share .....	0.68	0.55	0.53	0.80	2.56
2005 (1) (2)					
Revenues (3) (4) .....	745.2	552.9	537.4	680.3	2,515.8
Earnings attributable to Class A and Class B shares (4) .....	80.0	50.0	46.5	89.1	265.6
Earnings per Class A and Class B share .....	0.63	0.39	0.37	0.70	2.09
Diluted earnings per Class A and Class B share .....	0.63	0.39	0.37	0.69	2.08
2004 (1) (2)					
Revenues (3) (4) .....					3,011.4
Earnings attributable to Class A and Class B shares (5) .....					309.0
Earnings per Class A and Class B share (5) .....					2.44
Diluted earnings per Class A and Class B share (5) .....					2.43

### Notes:

- (1) There were no discontinued operations or extraordinary items during these periods.
- (2) Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, revenues and earnings for any quarter are not necessarily indicative of operations on an annual basis.
- (3) Reduced recoveries of natural gas costs in revenues in 2006 and 2005 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with Alberta Energy and Utilities Board directives.
- (4) Prior to the Transfer of the Retail Energy Supply Businesses on May 4, 2004, the cost of natural gas and electricity purchased for ATCO Gas' and ATCO Electric's customers was included in revenues. As ATCO Gas and ATCO Electric no longer purchase natural gas and electricity for their customers, revenues since May 4, 2004, have decreased accordingly.
- (5) Includes earnings of \$55.1 million, earnings per share of \$0.44 and diluted earnings per share of \$0.43 on the Transfer of the Retail Energy Supply Businesses for the year ended December 31, 2004.
- (6) The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.

## SELECTED ANNUAL AND QUARTERLY INFORMATION

	Year Ended December 31		
	2006	2005	2004
	(\$ Millions except per share data)		
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O (2).....	1.26	1.26	1.26
Series Q.....	1.48	1.48	1.48
Series R.....	1.33	1.33	1.33
Series S.....	1.65	1.65	1.65
Series T (2).....	1.26	1.26	1.26
Series U (2).....	1.26	1.26	1.26
Series V.....	1.31	1.31	1.31
Series W.....	1.45	1.45	1.45
Series X.....	1.50	1.50	1.50
Class A and Class B shares.....	1.40	1.10	1.06
Total assets.....	6,993.5	6,817.8	6,617.5
Long term debt.....	2,411.5	2,231.0	2,171.0
Non-recourse long term debt.....	626.7	673.8	760.9
Equity preferred shares.....	636.5	636.5	636.5
Class A and Class B share owners' equity.....	2,324.7	2,223.5	2,117.7

### Notes:

- (1) The above data has been extracted from the financial statements which have been prepared in accordance with Canadian generally accepted accounting principles and the reporting currency is the Canadian dollar.
- (2) The dividend was reset to \$1.09 (4.35%) for the period between December 2, 2006, and December 2, 2011.

## RESULTS OF OPERATIONS

The principal factors that caused variations in **revenues** over the eight most recently completed quarters were:

- reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with Alberta Energy and Utilities Board ("AEUB") directives;
- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections);
- availability of generating plants in ATCO Power and Alberta Power (2000) (refer to the Power Generation section);
- fluctuations in electricity and natural gas prices (refer to the Power Generation section); and
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section).

The principal factors that caused variations in **earnings** over the eight most recently completed quarters were:

- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections);
- fluctuations in electricity prices and related spark spreads in Alberta and the United Kingdom ("U.K.") (refer to the Power Generation section);
- the TXU Europe Settlement (refer to TXU Europe Settlement section);
- H.R. Milner income tax reassessment (refer to H.R. Milner Income Tax Reassessment section);
- availability of generating plants in ATCO Power and Alberta Power (2000) (refer to the Power Generation section);
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section);
- recent changes in income taxes and rates (refer to Recent Changes in Income Taxes and Rates section); and
- changes in share appreciation rights expense due to changes in Canadian Utilities Limited Class A non-voting share and ATCO Ltd. Class I Non-Voting Share prices (refer to Corporate and Other section).

## Consolidated Operations

**Revenues** for the three months ended December 31, 2006, **decreased** by \$9.2 million to \$671.1 million, primarily due to:

- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream; and
- lower franchise fees collected by ATCO Gas on behalf of cities and municipalities.

This decrease was partially offset by:

- higher availability (due to a planned outage in 2005), improved merchant performance, and higher natural gas fuel purchases recovered on a “no-margin” basis in ATCO Power’s U.K. operations; and
- colder temperatures in ATCO Gas.

**Revenues** for the year ended December 31, 2006, **decreased** by \$85.4 million to \$2,430.4 million, primarily due to:

- reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with Alberta Energy and Utilities Board (“AEUB”) directives;
- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream;
- lower business activity in ATCO Frontec; and
- impact of lower U.K. and Australia exchange rates on conversion of revenues to Canadian dollars in ATCO Power.

This decrease was partially offset by:

- improved merchant performance, higher natural gas fuel purchases recovered on a “no-margin” basis, and higher availability (due to a planned outage in 2005) in ATCO Power’s U.K. operations;
- higher storage revenues due to higher capacity leased, and the timing and demand of storage capacity sold, by ATCO Midstream; and
- higher customer rates for ATCO Electric (refer to Regulatory Matters – ATCO Electric section). The impact of the ATCO Electric GTA Decision on 2006 was positive as ATCO Electric had lower customer rates during 2005.

**Earnings attributable to Class A and Class B shares** for the three months ended December 31, 2006, **increased** by \$10.9 million (\$0.10 per share) to \$100.0 million (\$0.80 per share), primarily due to:

- higher earnings in ATCO Power’s Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market; and
- colder temperatures in ATCO Gas.

This increase was partially offset by:

- higher maintenance expenses due to a planned outage in 2006 at Alberta Power (2000)’s Battle River generating plant; and
- a settlement with a supplier was recorded in the fourth quarter of 2005 for damages due to equipment defects in ATCO Power’s U.K. operations.

**Earnings attributable to Class A and Class B shares** for the year ended December 31, 2006, **increased** by \$58.3 million (\$0.48 per share) to \$323.9 million (\$2.57 per share), primarily due to:

- higher earnings in ATCO Power’s Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market;
- higher margins received for natural gas liquids, higher storage earnings due to higher capacity leased, and the timing and demand of storage capacity sold by ATCO Midstream; and
- \$11.8 million adjustment in the second quarter of 2006 to reflect recent tax changes (refer to Recent Changes in Income Taxes and Rates section).

This increase was partially offset by:

- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section); and
- a 2005 AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in future income taxes recorded in ATCO Electric (refer to Regulatory Matters – ATCO Electric section).

**Return on common equity was 14.3% in 2006.**

**Operating expenses** (consisting of natural gas supply, purchased power, operation and maintenance, selling and administrative and franchise fee costs) for the three months ended December 31, 2006, **decreased** by \$15.5 million to \$383.5 million, primarily due to:

- lower costs for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher maintenance expenses due to a planned outage in 2006 at Alberta Power (2000)'s Battle River generating plant.

**Operating expenses** for the year ended December 31, 2006, **decreased** by \$163.2 million to \$1,390.7 million, primarily due to:

- reduced natural gas supply costs in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives; and
- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream.

**Depreciation and amortization expenses** for the three months ended December 31, 2006, **increased** by \$11.1 million to \$95.6 million, primarily due to:

- capital additions in 2006 and 2005.

**Depreciation and amortization expenses** for the year ended December 31, 2006, **increased** by \$37.0 million to \$348.5 million, primarily due to:

- capital additions in 2006 and 2005.

**Interest expense** for the three months ended December 31, 2006, **increased** by \$3.2 million to \$54.6 million, primarily due to:

- interest on new financings issued in 2006 and 2005 to fund capital expenditures in Utilities operations.

This increase was partially offset by:

- repayment of non-recourse financings in 2006 and 2005.

**Interest expense** for the year ended December 31, 2006, **increased** by \$12.9 million to \$222.9 million, primarily due to:

- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section); and
- interest on new financings issued in 2006 and 2005 to fund capital expenditures in Utilities operations.

This increase was partially offset by:

- repayment of non-recourse financings in 2006 and 2005.

**Interest and other income** for the three months ended December 31, 2006, **increased** by \$8.3 million to \$18.9 million, primarily due to:

- higher short term interest rates on cash balances.

**Interest and other income** for the year ended December 31, 2006, **increased** by \$21.9 million to \$58.5 million, primarily due to:

- Calgary Stores Block Decision (refer to Regulatory Matters – ATCO Gas section); and
- higher short term interest rates on larger cash balances.

**Income taxes** for the three months ended December 31, 2006, **decreased** by \$10.6 million to \$47.4 million, primarily due to:

- lower tax rates.

**Income taxes** for the year ended December 31, 2006, **decreased** by \$8.5 million to \$167.1 million, primarily due to:

- adjustment to reflect recent tax changes (refer to Recent Changes in Income Taxes and Rates section).

This decrease was partially offset by:

- higher earnings; and
- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section).

## Segmented Information

**Segmented revenues** for the three months and the year ended December 31, 2006, were as follows:

(\$ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2006	2005	2006	2005
	(unaudited)			
Utilities (1) .....	314.7	305.5	1,110.8	1,195.9
Power Generation (2) .....	226.7	211.0	799.5	770.7
Global Enterprises (2) .....	173.9	199.9	667.2	679.0
Corporate and Other .....	3.3	3.2	12.7	12.4
Intersegment eliminations .....	(47.5)	(39.3)	(159.8)	(142.2)
<b>Total .....</b>	<b>671.1</b>	<b>680.3</b>	<b>2,430.4</b>	<b>2,515.8</b>

Notes:

- (1) Reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives.
- (2) In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation.

**Segmented earnings attributable to Class A and Class B** shares for the three months and the year ended December 31, 2006, were as follows:

(\$ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2006	2005	2006	2005
	(unaudited)			
Utilities .....	43.7	32.5	121.2	106.0
Power Generation (1) .....	36.9	36.7	119.2	105.2
Global Enterprises (1) .....	27.3	27.6	101.0	78.8
Corporate and Other .....	(6.5)	(7.5)	(11.7)	(23.5)
Intersegment eliminations .....	(1.4)	(0.2)	(5.8)	(0.9)
<b>Total .....</b>	<b>100.0</b>	<b>89.1</b>	<b>323.9</b>	<b>265.6</b>

Note:

- (1) In 2006, ASHCOR Technologies was transferred from the Global Enterprises Business Group to the Power Generation Business Group. 2005 segmented figures have been reclassified to conform to the current basis of segmentation.

## Utilities

**Revenues** from the Utilities Business Group for the three months ended December 31, 2006, **increased** by \$9.2 million to \$314.7 million, primarily due to:

- colder temperatures in ATCO Gas;
- higher customer rates for ATCO Electric (refer to Regulatory Matters – ATCO Electric section). The impact of the ATCO Electric GTA Decision on the fourth quarter of 2006 was positive as ATCO Electric had lower customer rates during the fourth quarter of 2005; and
- customer growth in ATCO Gas.

This increase was partially offset by:

- lower franchise fees collected by ATCO Gas on behalf of cities and municipalities.

Temperatures in ATCO Gas for the three months ended December 31, 2006, were 5.2% colder than normal, compared to 14.1% warmer than normal for the corresponding period in 2005.

**Revenues** for the year ended December 31, 2006, **decreased** by \$85.1 million to \$1,110.8 million, primarily due to:

- reduced recoveries of natural gas costs in revenues in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives; and
- lower income taxes recovered from ATCO Electric's customers on a flow through basis, reflecting lower income tax rates in 2006.

This decrease was partially offset by:

- higher customer rates for ATCO Electric (refer to Regulatory Matters – ATCO Electric section). The impact of the ATCO Electric GTA Decision on 2006 was positive as ATCO Electric had lower customer rates during 2005; and
- customer growth in ATCO Gas.

Temperatures in ATCO Gas in 2006 were 5.5% warmer than normal, compared to 7.8% warmer than normal in 2005.

**Earnings** for the three months ended December 31, 2006, **increased** by \$11.2 million to \$43.7 million, primarily due to:

- colder temperatures in ATCO Gas.

This increase was partially offset by:

- lower sales per customer in ATCO Gas.

**Earnings** for the year ended December 31, 2006, **increased** by \$15.2 million to \$121.2 million, primarily due to:

- customer growth in ATCO Gas;
- Calgary Stores Block Decision and Red Deer Operating Centre Decision (refer to Regulatory Matters – ATCO Gas section); and
- colder temperatures in ATCO Gas.

This increase was partially offset by:

- a 2005 AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in future income taxes recorded in ATCO Electric (refer to Regulatory Matters – ATCO Electric section); and
- lower sales per customer in ATCO Gas.

**Operating expenses** for the year ended December 31, 2006, **decreased** by \$115.5 million to \$601.4 million, primarily due to:

- reduced natural gas supply costs in 2006 as ATCO Gas ceased selling natural gas from its natural gas storage facilities on March 31, 2005, in accordance with AEUB directives.

## Power Generation

**Revenues** from the Power Generation Business Group for the three months ended December 31, 2006, **increased** by \$15.7 million to \$226.7 million, primarily due to:

- higher availability (due to a planned outage in 2005), improved merchant performance, and higher natural gas fuel purchases recovered on a “no-margin” basis in ATCO Power's U.K. operations.

This increase was partially offset by:

- lower Power Purchase Arrangement (“PPA”) tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate (2006 – 8.75%, 2005 – 9.49%) that is based on long term Government of Canada bond yields plus 4.5%.

**Revenues** for the year ended December 31, 2006, **increased** by \$28.8 million to \$799.5 million, primarily due to:

- improved merchant performance, higher natural gas fuel purchases recovered on a “no-margin” basis, and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations; and
- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices.

This increase was partially offset by:

- impact of lower U.K. and Australia exchange rates on conversion of revenues to Canadian dollars in ATCO Power; and
- lower PPA tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate (2006 – 8.75%, 2005 – 9.49%) that is based on long term Government of Canada bond yields plus 4.5%.

**Earnings** for the three months ended December 31, 2006, **increased** by \$0.2 million to \$36.9 million, primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market; and
- improved merchant performance and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations.

This increase was partially offset by:

- higher maintenance expenses due to a planned outage in 2006 at Alberta Power (2000)'s Battle River generating plant; and
- a settlement with a supplier was recorded in the fourth quarter of 2005 for damages due to equipment defects in ATCO Power's U.K. operations..

Alberta Power Pool electricity prices for the three months ended December 31, 2006, averaged \$116.81 per megawatt hour, compared to average prices of \$117.07 per megawatt hour for the corresponding period in 2005. Natural gas prices for the three months ended December 31, 2006, averaged \$6.55 per gigajoule, compared to average prices of \$10.77 per gigajoule for the corresponding period in 2005. The consequence of these changes in electricity and natural gas prices was an average spark spread of \$67.66 per megawatt hour for the three months ended December 31, 2006, compared to \$36.31 per megawatt hour for the corresponding period in 2005.

Spark spread is related to the difference between Alberta Power Pool electricity prices and the marginal cost of producing electricity from natural gas. These spark spreads are based on an approximate industry heat rate of 7.5 gigajoules per megawatt hour.

Changes in spark spread affect the results of approximately 406 megawatts of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta owned capacity of approximately 1,709 megawatts and a world wide owned capacity of approximately 2,474 megawatts.

On January 1, 2006, the Alberta Balancing Pool announced the sale of its interest in the PPA for Alberta Power (2000)'s Sheerness generating plant to TransCanada Energy Ltd. On May 8, 2006, EPCOR Utilities Inc. announced the sale of its interest in the PPA for Alberta Power (2000)'s Battle River generating plant to ENMAX Corporation. These sales are not expected to have a material impact on the Corporation's operations or earnings.

Alberta Power (2000) continued to operate the Rainbow generating plant during 2006 and the electricity generated was sold to the Alberta Power Pool. Alberta Power (2000) had one year after the expiry of the PPA for the Rainbow generating plant (December 31, 2005) to determine whether to decommission the plant in order to fully recover plant decommissioning costs or to continue to operate the plant. The Alberta Electric System Operator ("AESO") and Alberta Power (2000) are currently negotiating a contract that, if executed, will result in Alberta Power (2000) continuing to operate the plant and be responsible for future decommissioning costs. Alberta Power (2000) has filed an application with the AEUB to decommission the plant and thereby preserve Alberta Power (2000)'s rights to fully recover plant decommissioning costs in the event negotiations with the AESO are unsuccessful.

**Earnings** for the year ended December 31, 2006, **increased** by \$14.0 million to \$119.2 million, primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales of electricity in the Alberta market;
- improved merchant performance and higher availability (due to a planned outage in 2005) in ATCO Power's U.K. operations; and

- \$7.2 million adjustment in the second quarter of 2006 for ATCO Power to reflect recent tax changes (refer to Recent Changes in Income Taxes and Rates section).

This increase was partially offset by:

- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section); and
- lower PPA tariffs due to declining rate bases at Alberta Power (2000)'s generating plants and a decline in the return on common equity rate (2006 – 8.75%, 2005 – 9.49%) that is based on long term Government of Canada bond yields plus 4.5%.

Alberta Power Pool electricity prices in 2006, averaged \$80.79 per megawatt hour, compared to average prices of \$70.36 per megawatt hour in 2005. Natural gas prices in 2006, averaged \$6.17 per gigajoule, compared to average prices of \$8.27 per gigajoule in 2005. The consequence of these changes in electricity and natural gas prices was an average spark spread of \$34.52 per megawatt hour in 2006, compared to \$8.32 per megawatt hour in 2005.

**Operating expenses** for the year ended December 31, 2006, **increased** by \$10.9 million to \$431.3 million, primarily due to:

- higher fuel costs due to the expiry in December 2005 of the PPA for Alberta Power (2000)'s Rainbow generating plant. Fuel costs were the responsibility of the PPA counterparty.

At December 31, 2006, all of ATCO Power's non-regulated independent generating plants were in service.

During the three months ended December 31, 2006, Alberta Power (2000)'s **deferred availability incentive** account **decreased** by \$41.0 million to \$39.6 million. The decrease was due to availability penalties paid associated with the planned outage in 2006 for Alberta Power (2000)'s Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices as well as normal amortization. During the three months ended December 31, 2006, the amortization of deferred availability incentives, recorded in revenues, was **unchanged** at \$2.7 million as compared to the same period in 2005.

During the year ended December 31, 2006, Alberta Power (2000)'s **deferred availability incentive** account **decreased** by \$20.1 million to \$39.6 million. The decrease was due to additional availability penalties paid associated with the planned outage in the fourth quarter of 2006 for Alberta Power (2000)'s Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices as well as normal amortization. During the year ended December 31, 2006, the amortization of deferred availability incentives, recorded in revenues, **increased** by \$1.7 million to \$10.6 million as compared to 2005.

## Global Enterprises

**Revenues** from the Global Enterprises Business Group for the three months ended December 31, 2006, **decreased** by \$26.0 million to \$173.9 million, primarily due to:

- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream; and
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream.

**Revenues** for the year ended December 31, 2006, **decreased** by \$11.8 million to \$667.2 million, primarily due to:

- lower recovery of natural gas costs in revenues due to customers supplying shrinkage gas in ethane extraction operations in ATCO Midstream;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream; and
- lower business activity in ATCO Frontec.

This decrease was partially offset by:

- higher storage revenues due to higher capacity leased, and the timing and demand of storage capacity sold, by ATCO Midstream; and
- increased sales of natural gas to affiliates by ATCO Midstream.

**Earnings** for the three months ended December 31, 2006, were **substantially unchanged**.

**Earnings** for the year ended December 31, 2006, **increased** by \$22.2 million to \$101.0 million, primarily due to:

- higher margins received for natural gas liquids, higher storage earnings due to higher capacity leased, and the timing and demand of storage capacity sold by ATCO Midstream.

**Operating expenses** for the year ended December 31, 2006, **decreased** by \$42.6 million to \$490.5 million, primarily due to:

- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream;
- lower natural gas prices for shrinkage gas used in natural gas liquids extraction in ATCO Midstream; and
- lower business activity in ATCO Frontec.

On January 30, 2007, ATCO Frontec announced it had been awarded a contract with the United Nations to provide camp support and food services to the United Nations Mission in Kosovo.

### Corporate and Other

**Earnings** from the Corporate and Other segment for the three months ended December 31, 2006 **increased** by \$1.0 million to \$(6.5) million, primarily due to:

- higher short term interest rates on larger cash balances.

**Earnings** for the year ended December 31, 2006 **increased** by \$11.8 million to \$(11.7) million, primarily due to:

- decreased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting Share prices since December 31, 2005; and
- higher short term interest rates on larger cash balances.

## REGULATORY MATTERS

Regulated operations are conducted by wholly owned subsidiaries of Canadian Utilities' wholly owned subsidiary, CU Inc.:

- ATCO Electric and its subsidiaries Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical;
- the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd.; and
- the generating plants of Alberta Power (2000).

Regulated operations in Alberta (except for the generating plants of Alberta Power (2000)) are subject to a generic cost of capital regime:

- in July 2004, the AEUB issued the generic cost of capital decision which established, among other things:
  - a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity;
    - rate of return adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast; and
    - adjustment mechanism similar to the method the National Energy Board uses in determining its formula based rate of return;
  - the capital structure for each utility regulated by the AEUB.
- in November 2005, the AEUB announced a generic return on common equity of 8.93% for 2006;
- in January 2006, the AEUB clarified that the generic return on equity determined on an annual basis in accordance with the generic cost of capital decision should apply to each year of the test period in the companies' applications. If no rate applications are filed for a particular year, then there will be no adjustment to the common equity rate of return for that year; and
- in November 2006, the AEUB announced a generic return on common equity of 8.51% for 2007.

In June 2005, as part of their rate applications, ATCO Electric and ATCO Gas submitted a filing to the AEUB that addressed certain common matters. ATCO Pipelines was also a party to this filing as the concerns were common to all three utilities:

- this filing included evidence regarding:
  - the appropriate ratemaking approach in the determination of utility revenue requirements;
  - treatment of pension costs, executive compensation and head office rent expense; and
  - the continued use of preferred shares as a form of financing for the three utilities;
- AEUB heard this filing in May 2006; and
- on October 11, 2006, the AEUB issued a decision (the “Common Matters Decision”) which resulted in no significant impact on earnings. Among other things, the decision upheld ATCO’s treatment of pension costs and approved the continued use of preferred shares. In addition, the decision approved minimal changes to head office rent expense and executive compensation.

## ATCO Electric

In March 2006, the AEUB issued a decision on ATCO Electric’s 2005 and 2006 General Tariff Application (“ATCO Electric GTA Decision”):

- which established, among other things, the amount of revenue to be collected in 2005 and 2006 from customers for transmission and distribution services, and confirmed the interim refundable rates approved by the AEUB in July 2005 (distribution services) and September 2005 (transmission services);
- ATCO Electric’s 2005 earnings negatively impacted by \$1.3 million, recorded in first quarter of 2006;
- ATCO Electric’s 2006 earnings reduced by an additional \$1.6 million, as compared to 2005 earnings, recorded throughout 2006; and
- return on common equity confirmed according to AEUB standardized rate of return methodology – 9.5% in 2005 and 8.93% in 2006.

In May 2006, the AEUB issued a decision on ATCO Electric’s 2003-2004 Regulated Rate Option Tariff Non-Energy Rates application dated November 2002:

- this decision approved, on an interim refundable basis, the collection in 2006 of a shortfall of \$2.7 million for 2003 and \$2.2 million for 2004 that was not previously incorporated into customer rates;
- the amounts approved for collection are subject to the outcome of an existing process regarding the pricing of services provided by ATCO I-Tek; and
- the impact of this decision increased ATCO Electric’s 2006 earnings by \$1.9 million and was recorded in the second quarter of 2006.

In August 2002, the AEUB issued a decision in which it denied ATCO Electric’s application to adjust its 2001 and 2002 transmission and distribution revenue requirements by \$4.6 million for changes in the amounts of future income taxes recorded:

- in May 2005, the AEUB changed its August 2002 decision and allowed ATCO Electric to increase its revenues and earnings by \$4.6 million. The impact of this decision was recorded in the second quarter of 2005.

In August 2006, the AEUB approved the first phase of the AESO’s application for the need to improve transmission infrastructure in northwest Alberta:

- AEUB decision grants the AESO approval to assign approximately \$300 million in projects to the Transmission Facility Owner, ATCO Electric;
- once assigned by the AESO, ATCO Electric will prepare and file facility applications with the AEUB. Construction will commence once approval to proceed is received from the AEUB; and
- the entire project was originally intended to be completed by 2009, but now is anticipated to be completed by 2011. As a result of price escalation caused by the change in completion date, coupled with the increasing costs of construction in Alberta, the entire project is now estimated to cost \$400 million.

In November 2006, ATCO Electric filed a general tariff application with the AEUB for the 2007 and 2008 test years:

- requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta;
- a decision from the AEUB on the general tariff application is not expected until late 2007;

- in November 2006, ATCO Electric filed an application requesting interim refundable rates for transmission and distribution operations, pending the AEUB's decision on the general tariff application; and
- on December 19, 2006, ATCO Electric received a decision from the AEUB approving interim refundable rate increases amounting to 50% of ATCO Electric's requested increases for transmission and distribution operations.

## ATCO Gas

In January 2006, the AEUB issued a decision on ATCO Gas' 2005, 2006 and 2007 General Rate Application ("ATCO Gas GRA Decision"):

- which, among other things, established the amount of revenue to be collected over the period 2005 to 2007 from customers for natural gas distribution service and approved a return on common equity as determined by the AEUB's standardized rate of return methodology – 9.5% in 2005, 8.93% in 2006 and 8.51% in 2007;
- the final impact of the decision will not be known until a subsequent regulatory process is finalized; and
- a decision from the AEUB with respect to a second regulatory process that was pending at the end of 2005 was received on October 11, 2006; the effect of this decision on the earnings of the Corporation was not material.

In May 2006, the City of Calgary filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:

- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the calculation of working capital needed by ATCO Gas to operate its Carbon natural gas storage facility; and
- the AEUB issued its decision on January 17, 2007, denying the City of Calgary's application.

In October 2006, ATCO Gas also filed a Review and Variance application with the AEUB for the ATCO Gas GRA Decision:

- the application alleges that the AEUB made errors in the ATCO Gas GRA Decision related to the approved level of administrative expenses;
- in December 2006, the AEUB issued a decision in which it acknowledged an error for a portion of the administrative expenses in question; and
- a further AEUB decision on the remainder of this application is expected in the 2nd quarter of 2007.

In October 2001, the AEUB approved the sale by ATCO Gas of certain properties in the City of Calgary, known as the Calgary Stores Block, for \$6.6 million (excluding costs of disposition). As a result of this decision (the "Calgary Stores Block Decision"):

- \$4.1 million of the proceeds were allocated by the AEUB to customers and \$1.8 million to ATCO Gas;
- ATCO Gas appealed the decision to the Alberta Court of Appeal which overturned the decision and directed the AEUB to allocate \$5.4 million of the proceeds to ATCO Gas;
- City of Calgary appealed this decision to the Supreme Court of Canada, which also granted ATCO Gas leave to cross-appeal the decision;
- the Supreme Court of Canada rendered its decision on February 9, 2006, dismissing the City of Calgary's appeal and allowing ATCO Gas' cross-appeal. The AEUB was directed to issue a new decision in accordance with the Supreme Court's ruling;
- ATCO Gas requested that the AEUB address the Supreme Court of Canada decision; and
- the AEUB complied with the Supreme Court of Canada decision on August 11, 2006, and ATCO Gas recorded additional net proceeds totaling \$4.1 million from the sale and increased earnings of \$3.7 million after income taxes in the third quarter of 2006.

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta. ATCO Gas has leased the entire storage capacity of the facility to ATCO Midstream. ATCO Gas has taken the position that the facility is no longer required for utility service and should be removed from regulation. In the process of obtaining AEUB approval, the following events are significant:

- in July 2004, the AEUB initiated a written process to consider its role in regulating the operations of the facility;

- in June 2005, the AEUB issued a decision with respect to this process. In addition to addressing other matters, the decision found that the AEUB has the authority, when necessary in the public interest, to direct a utility to utilize a particular asset in a specific manner, even over the objection of the utility;
- ATCO Gas filed for leave to appeal the decision with the Alberta Court of Appeal;
- in October 2005, the AEUB established processes to review the use of the facility for utility purposes;
- a hearing to review the use of the facility for revenue generation was held in April 2006 and a hearing to review the use of the facility for load balancing was held in June 2006. On October 11, 2006 the AEUB issued a decision confirming ATCO Gas' position that the facility is no longer required for utility service with respect to the use of the facility for load balancing purposes. The City of Calgary has filed a leave to appeal and a review and variance application of this decision; and
- on February 5, 2007, the AEUB issued a decision in which it determined that a legitimate utility use for the facility is that it be used for purposes of generating revenues to offset customer rates. The AEUB has directed ATCO Gas to continue to lease the entire storage capacity of the facility to ATCO Midstream. The AEUB will conduct a further process to determine if it is appropriate that 100% or some lesser portion of this facility should be used to offset customer rates. (Refer to Business Risks - Regulated Operations - Carbon Natural Gas Storage Facility section).

ATCO Gas has filed an application with the AEUB 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 Corporation's pipelines) that have impacted ATCO Gas' deferred gas account:

- in April 2005, the AEUB issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in a decrease to ATCO Gas' 2005 revenues and earnings of \$1.8 million and \$1.2 million, respectively; and
- City of Calgary filed for leave to appeal the AEUB's decision. ATCO Gas filed a cross appeal of the AEUB's decision. The leave to appeal was heard by the Alberta Court of Appeal on April 18, 2006. On July 7, 2006 the Alberta Court of Appeal issued its decision granting the City of Calgary's leave to appeal on the question of whether the AEUB erred in law or jurisdiction in assuming that it had the authority to allow recovery in 2005, for costs relating to prior years. ATCO Gas' cross appeal was denied. A hearing with the Alberta Court of Appeal has been scheduled for April 13, 2007.

In October 2005, ATCO Gas filed an application with the AEUB to approve the sale of its Red Deer Operating Centre:

- in December 2005, the AEUB approved the sale and deferred its decision on the distribution of net proceeds of \$1.0 million until the Supreme Court of Canada rendered a judgment in the appeal regarding the Calgary Stores Block disposition and allocation of proceeds discussed above;
- the Supreme Court of Canada rendered its decision on the Calgary Stores Block matter on February 9, 2006;
- in February 2006, ATCO Gas submitted a filing to the AEUB to approve the allocation of the net proceeds;
- on March 16, 2006, the AEUB suspended the process convened to approve allocation of the net proceeds pending resolution of certain issues arising in connection with the Supreme Court's Calgary Stores Block decision. The net proceeds of the sale remained in trust pending AEUB approval; and
- on August 16, 2006, ATCO Gas requested that the process re-convene in light of the AEUB's approval of the Calgary Stores Block application. The AEUB issued a call for comments which concluded on September 14, 2006 and on December 13, 2006 the AEUB issued a decision approving the distribution of proceeds to ATCO Gas resulting in increased revenue of \$1.0 million and earnings of \$0.7 million for ATCO Gas.

## ATCO Pipelines

The AEUB has delayed its review of the competitive natural gas pipeline issues under AEUB jurisdiction until 2007. This review is expected to address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd.

## Other Matters

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

## LIQUIDITY AND CAPITAL RESOURCES

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

**Funds generated by operations** for the three months ended December 31, 2006, **decreased** by \$19.4 million to \$168.4 million, primarily due to:

- decreased availability incentives in Alberta Power (2000), primarily due to availability penalties paid associated with the planned outage in 2006 for the Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices.

This decrease was partially offset by:

- increased earnings.

**Funds generated by operations** for the year ended December 31, 2006, **decreased** by \$1.8 million to \$657.5 million, primarily due to:

- lower proceeds received from the TXU Europe Settlement (refer to TXU Europe Settlement section); and
- decreased availability incentives in Alberta Power (2000), primarily due to availability penalties paid associated with the planned outage in 2006 for the Battle River generating plant which occurred during a period of high Alberta Power Pool electricity prices.

This decrease was partially offset by:

- increased earnings.

**Investing activities** for the three months ended December 31, 2006, **increased** by \$0.3 million to \$160.6 million, primarily due to:

- changes in non-cash working capital.

This increase was partially offset by:

- increased contributions by utility customers for extensions to plant.

**Purchase of property, plant and equipment** for the three months ended December 31, 2006, **increased** by \$2.8 million to \$184.0 million, primarily due to:

- increased investment in regulated electric distribution and transmission projects.

This increase was partially offset by:

- decreased investment in regulated natural gas distribution projects.

**Investing activities** for the year ended December 31, 2006, **increased** by \$57.1 million to \$527.5 million, primarily due to:

- 2005 proceeds on the transfer of the retail energy supply businesses;
- increased capital expenditures;
- changes in non-cash working capital; and
- H.R. Milner Income Tax Reassessment (refer to H.R. Milner Income Tax Reassessment section).

This increase was partially offset by:

- increased contributions by utility customers for extensions to plant; and
- changes in non-current deferred electricity costs.

**Purchase of property, plant and equipment** for the year ended December 31, 2006, **increased** by \$41.0 million to \$567.7 million, primarily due to:

- increased investment in regulated electric distribution and transmission and regulated natural gas transportation projects.

This increase was partially offset by:

- decreased investment in regulated natural gas distribution projects.

During the three months ended December 31, 2006, the Corporation **issued**:

- \$160.0 million of 4.801% Debentures due November 22, 2021; and
- \$160.0 million of 5.032% Debentures due November 20, 2036.

During the three months ended December 31, 2006, the Corporation **redeemed**:

- \$175.0 million of 4.84% Debentures due November 6, 2006; and
- \$12.6 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of \$132.4 million.

During the year ended December 31, 2006, the Corporation **issued**:

- \$160.0 million of 4.801% Debentures due November 22, 2021;
- \$160.0 million of 5.032% Debentures due November 20, 2036; and
- \$35.5 million of other long term debt.

During the year ended December 31, 2006, the Corporation **redeemed**:

- \$175.0 million of 4.84% Debentures due November 6, 2006; and
- \$64.6 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of \$115.9 million.

**Net purchase** of Class A non-voting shares for the three months ended December 31, 2006, **decreased** by \$4.6 million to \$1.9 million, primarily due to decreased share purchases in 2006.

**Net purchase** of Class A non-voting shares for the year ended December 31, 2006, **increased** by \$64.8 million to \$67.5 million, primarily due to increased share purchases in 2006.

**Foreign currency translation** for the three months ended December 31, 2006, positively impacted the Corporation's cash position by \$11.4 million to \$11.6 million, primarily as a result of:

- changes in the U.K. exchange rate which resulted in an increase in the value of cash balances denominated in U.K. pounds when translated into Canadian dollars.

**Foreign currency translation** for the year ended December 31, 2006, positively impacted the Corporation's cash position by \$27.5 million to \$16.3 million, primarily as a result of:

- changes in the U.K. exchange rate which resulted in an increase in the value of cash balances denominated in U.K. pounds when translated into Canadian dollars.

At December 31, 2006, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

	Total	Used	Available
(\$ Millions)			
Long term committed .....	326.0	47.4	278.6
Short term committed .....	600.0	14.0	586.0
Uncommitted .....	69.1	7.1	62.0
Total .....	995.1	68.5	926.6

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

**Capital expenditures** to maintain capacity, meet planned growth and fund future development activities are expected to be approximately \$725 million in 2007. The majority of these expenditures are uncommitted and relate primarily to utility operations.

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

Contractual Obligations	Total	Payments Due by Period			
		Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
(\$ Millions)					
Long term debt.....	2,411.5	54.5	225.0	272.0	1,860.0
Non-recourse long term debt.....	686.0	59.3	150.3	124.2	352.2
Operating leases.....	61.6	18.5	24.6	13.7	4.8
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1).....	4.5	0.5	1.0	1.0	2.0
Alberta Power (2000) coal purchase contracts (2).....	607.7	47.7	99.2	105.2	355.6
ATCO Power natural gas fuel supply contracts (3).....	248.1	52.4	104.8	74.0	16.9
ATCO Power operating and maintenance agreements (4).....	198.2	21.2	45.3	38.4	93.3
Capital expenditures (5).....	45.4	45.4	-	-	-
Other.....	7.8	7.8	-	-	-
<b>Total.....</b>	<b>4,270.8</b>	<b>307.3</b>	<b>650.2</b>	<b>628.5</b>	<b>2,684.8</b>

*Notes:*

- (1) *ATCO Gas has ongoing obligations to purchase fixed quantities of natural gas from various gas producers at market prices that are in effect at the time the quantities are purchased. These obligations relate primarily to operational contracts pertaining to the Carbon natural gas storage facility, which was not included in the Transfer of the Retail Energy Supply Businesses to DEML and continues to be subject to AEUB regulation. Some of these obligations are for the life of the gas reserves. The estimated value of these purchase obligations is based on the market price of natural gas in effect on December 31, 2006, and assumes a remaining life of 10 years for the gas reserves commencing January 1, 2004. DEML has agreed to purchase the natural gas purchased under these contracts at the prices paid by ATCO Gas.*
- (2) *Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the power purchase arrangements.*
- (3) *ATCO Power has various contracts to purchase natural gas for certain of its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 78% of these costs. The balance of 22%, related to ATCO Power's Barking generating plant, is currently being recovered through merchant sales in the U.K. electricity market. ATCO Power's merchant generating plants in Alberta do not have any long term contracts to purchase natural gas.*
- (4) *ATCO Power has various contracts with suppliers to provide operating and maintenance services at certain of its generating plants.*
- (5) *Various contracts to purchase goods and services with respect to capital expenditure programs.*

**Current and long term future income tax liabilities** of \$195.0 million at December 31, 2006, are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

On May 20, 2005, the Corporation commenced a **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A shares. The bid expired on May 19, 2006. Over the life of the bid, 348,100 shares were purchased, of which 195,600 were purchased in 2005 and 152,500 were purchased in 2006. On May 23, 2006, the Corporation 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, 2007. From May 23, 2006, to February 16, 2007, 1,679,700 shares have been purchased, all of which were purchased in 2006.

It is the policy of the Corporation to **pay dividends** quarterly on its Class A and Class B shares. For the first quarter of 2006, the quarterly dividend payment on the Corporation's Class A and Class B shares **increased** by \$0.01 to \$0.285 per share. The quarterly dividend payment for the second quarter remained unchanged at \$0.285 per share. For the third quarter of 2006, the quarterly dividend was increased by \$0.005 to \$0.29 per share. The Corporation also approved a one-time special dividend of \$0.25 per share. Both the third quarter dividend of \$0.29 per share and the one-time special dividend of \$0.25 per share were paid on September 1, 2006, to shareholders of record on August 9, 2006. Based on approximately 126.3 million shares then outstanding, the one-time special dividend totaled approximately \$31.6 million. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. For the first quarter of 2007, the quarterly dividend payment has been **increased** by \$0.015 to \$0.305 per share. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

On April 12, 2006, CU Inc. filed a **base shelf prospectus** which permits CU Inc. to issue up to an aggregate of \$850.0 million of debentures over the twenty-five month life of the prospectus.

- on November 20, 2006, the Corporation issued \$160.0 million of 4.801% Debentures due November 22, 2021, at a price of 100 to yield 4.801%, and \$160.0 million of 5.032% Debentures due November 20, 2036, at a price of 100 to yield 5.032%. The proceeds of these issues were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

## OUTSTANDING SHARE DATA

At February 16, 2007, the Corporation had outstanding 81,462,286 Class A shares and 43,926,484 Class B shares.

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

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

Of the 6,400,000 Class A shares reserved for issuance in respect of options under the Corporation's stock option plan, 2,626,800 Class A shares are available for issuance at December 31, 2006. Options may be granted to directors, officers and key employees of the Corporation and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 16, 2007, options to purchase 1,368,900 Class A shares were outstanding.

## TRANSACTIONS WITH RELATED PARTIES

The Corporation's transactions with related parties are in the normal course of business and under normal commercial terms. For a description of these transactions, refer to Note 19 to the consolidated financial statements for the year ended December 31, 2006.

## BUSINESS RISKS

The current Federal government favours a made in Canada approach to deal with climate change instead of the Kyoto Protocol which the previous government had ratified. The Corporation is unable to determine what impact the Clean Air Act may have on its operations as the Government of Canada has not yet provided industry specific details for its 2006 Climate Change Plan. While it is not certain, it is anticipated that the Corporation's PPA's relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the Clean Air Act.

## Regulated Operations

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

### Carbon Natural Gas Storage Facility

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

### Weather

Weather fluctuations have a significant impact on throughput in ATCO Gas. Since approximately 50% of ATCO Gas' delivery charge is recovered based on throughput, ATCO Gas' revenues and earnings are sensitive to weather. Weather that is 10% warmer or colder than normal temperatures impacts annual earnings by approximately \$10.0 million.

### ATCO I-Tek Services

ATCO Electric, ATCO Gas and ATCO Pipelines purchase information technology services, and ATCO Electric and ATCO Gas also purchase customer care and billing services, from ATCO I-Tek. The recovery of these costs in customer rates are subject to AEUB approval. Since 2003, the costs have been approved on a placeholder basis, and are subject to final AEUB approval after completion of an ongoing collaborative benchmarking process.

### Transfer of the Retail Energy Supply Businesses

On May 4, 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy Marketing Limited and one of its affiliates (collectively "DEML"), a subsidiary of Centrica plc.

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

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

The Corporation has provided a guarantee of ATCO Gas', ATCO Electric's and ATCO I-Tek Business Services' payment and indemnity obligations to DEML contemplated under the transaction agreements.

## Late Payment Penalties on Utility Bills

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

### Alberta Power (2000)

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

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

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

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

At December 31, 2006, the Corporation had recorded \$39.6 million of deferred availability incentives.

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

Alberta Environment implemented mercury emission regulations in March 2006 for coal-fired generating plants. Owners of coal-fired generating plants are required to submit by April 1, 2007, proposals on capturing at least 70% of the mercury in the coal burned in their plants. The proposals for mercury emission reduction must be implemented by 2010. While it is not certain, it is anticipated that the Corporation's PPA's relating to its coal-fired generating plants will allow the Corporation to recover most of the costs associated with complying with the new regulation.

## Measurement Inaccuracies in Metering Facilities

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

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

## Non-Regulated Operations

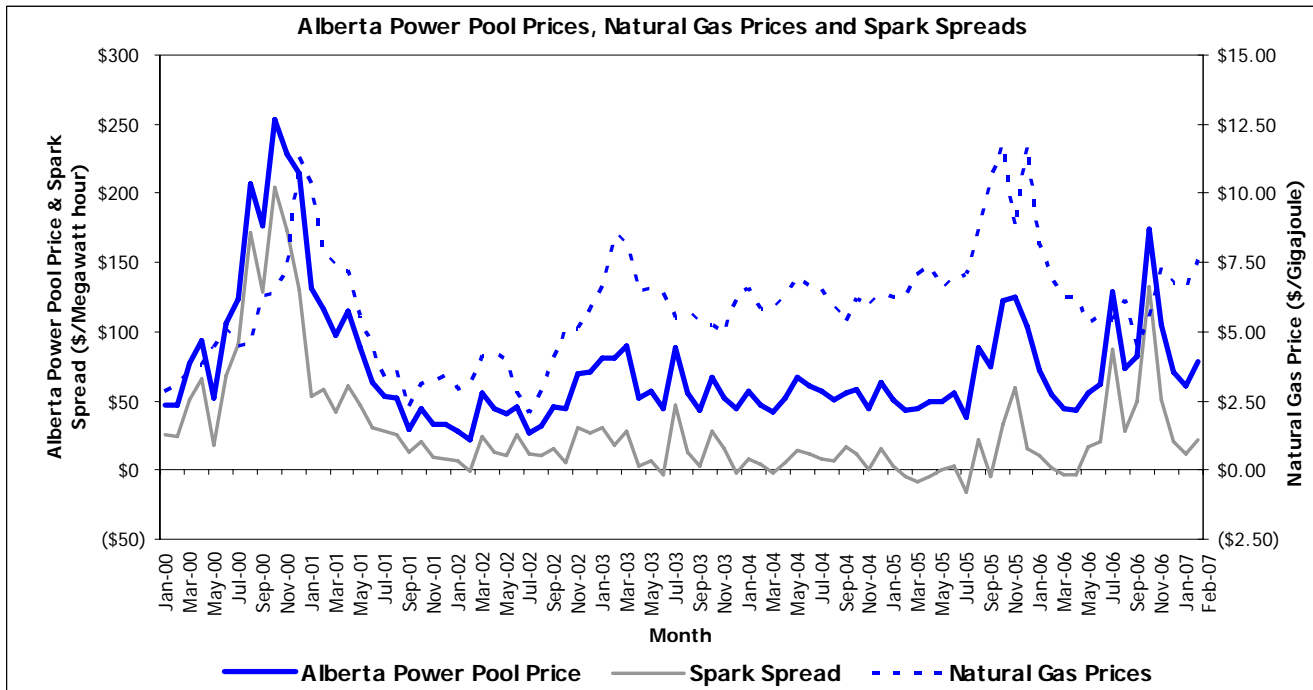
The Corporation's non-regulated operations are complementary to its traditional regulated businesses and are related to them in terms of skills, knowledge and experience. The Corporation accounts for its non-regulated operations separately from its regulated operations. The Corporation's non-regulated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

## ATCO Power

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

ATCO Power's generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. In 2006, sales from approximately 71% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 29% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. In 2007, these percentages are expected to be approximately the same. These sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool are from gas-fired generating plants, and as a result operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a good correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation. The correlation is expected to increase in the future as customer load grows and older plants are decommissioned.

Alberta Power Pool electricity prices, natural gas prices and related spark spreads can be very volatile, as shown in the following graph, which illustrates a range of prices experienced during the period January 2000 to February 2007.



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

Since October 2004, the output from ATCO Power's Barking generating plant previously sold to TXU Europe (refer to TXU Europe Settlement section) has been sold into the U.K. power exchange market. In the U.K., electricity generators, on average, sell over 90% of their output to electricity suppliers in bilateral contracts, use power exchanges for approximately 7% of their output, and sell the remaining 2-3% via the Balancing Mechanism. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants, and earlier this year the market experienced an increase in electricity prices due to the increased world prices for natural gas. Since then natural gas prices have softened with additional natural gas infrastructure coming on stream and the slightly lower oil prices. Nevertheless, the Barking generating plant has a long term, fixed price gas purchase agreement and, as a result, has been able to experience increased margins due to the high market prices for electricity. Changes in the U.K. market electricity prices may have an impact on the Corporation's earnings and cash flow from operations in the future.

ATCO Power has financed its non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities Limited has provided a number of guarantees related to ATCO Power's obligations under non-recourse loans associated with certain of its projects. The guarantees outstanding at December 31, 2006, are described in Note 12 to the consolidated financial statements for the year ended December 31, 2006. To date, Canadian Utilities Limited has not been required to pay any of its guaranteed obligations.

#### ATCO Midstream

Timing, capacity and demand of ATCO Midstream's storage business as well as changes in market conditions may impact the Corporation's earnings and cash flow from storage operations.

ATCO Midstream extracts ethane and other natural gas liquids from natural gas streams at its extraction plants. These products are sold under either long term cost of service arrangements or market based arrangements. Changes in market conditions may impact the Corporation's earnings and cash flow from natural gas liquids extraction operations.

### ATCO Frontec

ATCO Frontec's operations include providing support to military agencies in foreign locations which may be subject to political risk.

On December 23, 2005, the Government of Canada filed a claim in the amount of \$70 million which alleges that the Corporation is liable for the destruction of property owned by the Governments of Canada and the United States. The Corporation believes that the claim is defensible and, in any event, has sufficient insurance coverage in place to cover any material amounts that might become payable as a result of the claim. Accordingly, the claim is not expected to have any material impact on the financial position of the Corporation.

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

## CONTINGENCIES

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

## HEDGING

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes. For details on the financial instruments in place at December 31, 2006, refer to Note 21 to the consolidated financial statements for the year ended December 31, 2006.

## OFF-BALANCE SHEET ARRANGEMENTS

At December 31, 2006, unrecorded future income tax liabilities of the regulated operations amounted to \$141.3 million and unrecorded future income tax assets of other operations amounted to \$0.5 million. The liabilities include \$14.6 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. There are tax loss carryforwards of \$0.4 million for Canadian subsidiary corporations and \$7.6 million for a foreign subsidiary corporation for which no tax benefit has been recorded. The losses for Canadian subsidiary corporations begin to expire in 2010 and the losses for the foreign subsidiary corporation do not expire. For additional information on the Corporation's unrecorded future income tax liabilities, refer to Note 7 to the consolidated financial statements for the year ended December 31, 2006.

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

## CRITICAL ACCOUNTING ESTIMATES

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

### Deferred Availability Incentives

As noted in the Business Risks section, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. As at December 31, 2006, the Corporation had recorded \$39.6 million of deferred availability incentives. The amortization of deferred availability incentives, which was recorded in revenues, amounted to \$10.6 million in 2006.

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

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately \$5.0 million, whereas the low case scenario would have resulted in lower revenues of approximately \$4.6 million.

### Employee Future Benefits

The expected long term rate of return on pension plan assets is determined at the beginning of the year on the basis of the long bond yield rate plus an equity and management premium that reflects the plan asset mix. Actual balanced fund performance over a longer period suggests that this premium is about 1%, which, when added to the long bond yield rate of 5.1% at the beginning of 2006, resulted in an expected long term rate of return of 6.1% for 2006. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, and asset diversification effect on portfolio returns.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years. The expected long term rate of return has declined over the past five years, from 8.1% in 2001 to 6.1% in the year ended December 31, 2006. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the same period has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

The liability discount rate that is used to calculate the cost of benefit obligations reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments. The liability discount rate has also declined over the same five year period, from 6.9% at the end of 2001 to 5.1% at the end of 2006. The result has been an increase in benefit obligations (i.e., an experience loss), which is contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10 percent of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation began amortizing a portion of the net cumulative experience losses on plan assets and accrued

benefit obligations in 2003 for both pension benefit plans and other post employment benefit plans and continued this amortization during the three months and the year ended December 31, 2006.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the three months and the year ended December 31, 2006, are as follows: for drug costs, 8.5% starting in 2006 grading down over 7 years to 4.5%, and for other medical and dental costs, 4.0% for 2006 and thereafter. Combined with higher claims experience, the effect of these changes has been to increase the costs of other post employment benefits.

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

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2006 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2006 Pension Benefit Plans		2006 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
(\$ Millions)				
Expected long term rate of return on plan assets				
1% increase (1) .....	-	(3.4)	-	-
1% decrease (1) .....	-	3.4	-	-
Liability discount rate				
1% increase (1) .....	(79.5)	(6.4)	(3.7)	(0.4)
1% decrease (1) .....	101.7	7.5	4.7	0.5
Future compensation rate				
1% increase (1) .....	22.9	2.9	-	-
1% decrease (1) .....	(20.8)	(2.6)	-	-
Long term inflation rate				
1% increase (1)(2)(3) .....	34.5	3.9	4.2	0.7
1% decrease (1) (3) .....	(60.4)	(6.9)	(3.4)	(0.5)

*Notes:*

- (1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AEUB decision to record costs of employee future benefits in the regulated operations, excluding Alberta Power (2000), when paid rather than accrued.
- (2) The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.
- (3) The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

## CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2007, the Corporation prospectively adopted the recommendations of the Canadian Institute of Chartered Accountants ("CICA") pertaining to financial instruments, hedging and comprehensive income. These recommendations require certain financial instruments and hedge positions to be recorded at their fair value. They also introduce the concept of comprehensive income and accumulated other comprehensive income. Financial instruments designated as "held-for-trading" and "available-for-sale" will be carried at their fair value while financial instruments classified as "loans and receivables" and "held-to-maturity" will be carried at their amortized cost. All derivatives will be carried on the consolidated balance sheet at their

fair value, including derivatives designated as hedges. The effective portion of unrealized gains and losses on cash flow hedges and the cumulative foreign currency translation adjustments arising from self-sustaining investments in foreign operations will be carried in Accumulated Other Comprehensive Income, a component of Class A and Class B Share Owners Equity on the consolidated balance sheet. Any ineffective portions of gains and losses on hedges will be taken into earnings immediately. Changes in value of fair value hedges will be recognized in earnings as they occur. The Corporation is unable to determine at this time the impact of adopting these recommendations on earnings or assets of the Corporation.

Effective January 1, 2006, the Corporation retroactively adopted the CICA Emerging Issues Abstract regarding conditional asset retirement obligations. This abstract requires an entity to record a liability for an asset retirement obligation where the timing and/or method of settlement are conditional upon the occurrence of a future event that may or may not be within the control of the entity. Adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

Effective January 1, 2006, the Corporation retroactively adopted the CICA Emerging Issues Abstract regarding stock based compensation for employees eligible to retire before the vesting date. This abstract requires an entity to recognize the compensation cost attributable to such an award over the period from grant date to the date the employee becomes eligible to retire. Since the Corporation does not have stock based compensation plans that contain such provisions, adoption of this abstract had no effect on the consolidated financial statements for the year ended December 31, 2006.

February 21, 2007