



CANADIAN UTILITIES LIMITED
An **ATCO** Company

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

**FOR THE YEAR ENDED
DECEMBER 31, 2005**

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS ("MD&A")

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, 2005, and the audited consolidated financial statements for the year ended December 31, 2005. Additional information relating to the Corporation, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com.

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

The common share capital of the Corporation consists 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 purchase 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.

CONTROLS AND PROCEDURES

As of December 31, 2005, 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. Because of the inherent limitations in all control systems, an evaluation of controls 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.

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, and transactions between Business Groups are eliminated in all reporting of the Corporation’s consolidated financial information. For additional information on the Corporation’s Business Groups, refer to Note 22 to the consolidated financial statements.

TWO FOR ONE SHARE SPLIT

In July 2005, the Corporation’s board of directors approved a two-for-one share split of the outstanding Class A and Class B shares. The share split took the form of a stock dividend whereby share owners received one additional Class A share for each Class A share held as of the record date and one additional Class B share for each Class B share held as of the record date. The stock dividend was paid on September 15, 2005 to share owners of record at the close of business on August 29, 2005. All share, stock option and per share amounts have been retroactively restated to reflect this share split.

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 (“Transfer of the Retail Energy Supply Businesses”). Proceeds of the transfer were \$90 million, of which \$45 million was paid at closing, and the remainder was paid on May 4, 2005. Net proceeds, after adjustments related to legal, transition and other deferred costs pertaining to the Transfer of the Retail Energy Supply Businesses, resulted in a gain of \$63.3 million before income taxes of \$8.2 million and increased 2004 earnings by \$55.1 million.

The Corporation’s revenues and natural gas supply and purchased power costs after May 4, 2004 were reduced accordingly for 2004 and thereafter. Subsequent to May 4, 2004, ATCO Gas continued to purchase natural gas on behalf of DEML until the transfer of the relevant ATCO Gas natural gas purchase contracts to DEML was completed in September 2004. There is no ongoing impact on earnings resulting from the transfer of these businesses as natural gas and electricity have historically been sold to customers on a “no-margin” basis. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

Under the various transaction agreements, 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 “transferred functions”).

On May 4, 2004, DEML commenced supplying natural gas and electricity at regulated rates to residential, farm, commercial and small industrial customers in the ATCO Gas and ATCO Electric service areas and billing customers for their natural gas and electricity service.

If DEML fails to perform all or part of the transferred functions, ATCO Gas and ATCO Electric will be required under existing legislation to perform such functions in the interim until DEML is able to perform such functions. 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 Alberta Energy and Utilities Board (“AEUB”) to do so), the agreements will terminate and 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. The Centrica guarantee and letter of credit include limits for certain categories of claims, which limits cease to apply if the agreements are terminated. If the amount available to be drawn under the letter of credit at any time falls below \$200 million, the agreements with DEML will terminate and the functions will revert to ATCO Gas and ATCO Electric with no refund of the transfer proceeds to DEML by ATCO Gas and ATCO Electric.

The Corporation has provided a guarantee of ATCO Gas’, ATCO Electric’s and ATCO I-Tek Business Services’ payment and indemnity obligations in respect of the ongoing relationships contemplated under the transaction agreements.

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

ATCO Gas and ATCO Electric have also agreed not to compete in the regulated and unregulated retail energy business in Alberta for a period of ten years.

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 is expected in the second quarter of 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 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.

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>				
2005					
Revenues (1)	745.2	552.9	537.4	680.3	2,515.8
Earnings attributable to Class A and Class B shares (4) (5)	80.0	50.0	46.5	89.1	265.6
Earnings per Class A and Class B share (4) (5)	0.63	0.39	0.37	0.70	2.09
Diluted earnings per Class A and Class B share (4) (5)	0.63	0.39	0.37	0.69	2.08
2004					
Revenues (1)	1,169.2	674.7	530.5	637.0	3,011.4
Earnings attributable to Class A and Class B shares (2) (4) (5)	74.5	100.2	44.0	90.3	309.0
Earnings per Class A and Class B share (2) (4) (5)	0.59	0.79	0.35	0.71	2.44
Diluted earnings per Class A and Class B share (2) (4) (5)	0.59	0.78	0.35	0.71	2.43
2003					
Revenues					3,742.6
Earnings attributable to Class A and Class B shares (3) (4) (5)					259.1
Earnings per Class A and Class B share (3) (4) (5)					2.04
Diluted earnings per Class A and Class B share (3) (4) (5)					2.03

Notes:

- (1) 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.
- (2) 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 three months ended June 30, 2004, and for the year ended December 31, 2004.

- (3) 2003 earnings attributable to Class A and Class B shares have been restated for retroactive changes in the methods of accounting for asset retirement obligations and stock based compensation.
- (4) There were no discontinued operations or extraordinary items during these periods.
- (5) Due to the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta and the timing of rate decisions, earnings for any quarter are not necessarily indicative of operations on an annual basis.
- (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.

	Year Ended December 31		
	2005	2004	2003
	(\$ Millions except per share data)		
Cash dividends declared per share (1):			
Series Second Preferred Shares:			
Series O	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	1.26	1.26	1.26
Series U	1.26	1.26	1.26
Series V	1.31	1.31	1.31
Series W (1)	1.45	1.45	1.44
Series X (2)	1.50	1.50	0.93
Class A and Class B shares	1.10	1.06	1.02
Total assets	6,815.7	6,617.5	6,237.6
Long term debt	2,231.0	2,171.0	1,805.3
Non-recourse long term debt	673.8	760.9	806.1
Equity preferred shares	636.5	636.5	636.5
Class A and Class B share owners' equity	2,223.5	2,117.7	1,948.5

Notes:

- (1) Issued December 3, 2002.
- (2) Issued April 17, 2003.
- (3) 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.

RESULTS OF OPERATIONS

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

- lower sales of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses section), and lower prices of electricity and natural gas purchased for customers on a “no-margin” basis prior to May 4, 2004 (refer to the Utilities section);
- fluctuations in electricity and natural gas prices (refer to the Power Generation section);
- fluctuations in temperatures (refer to the Utilities section);
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section); and
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections).

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

- gain on the Transfer of the Retail Energy Supply Businesses (refer to the Transfer of the Retail Energy Supply Businesses and the Utilities sections);

- fluctuations in electricity prices and related spark spreads in Alberta and the United Kingdom (“U.K.”) (refer to the Power Generation section);
- changes in market conditions in natural gas liquids and storage operations (refer to the Global Enterprises section);
- fluctuations in temperatures (refer to the Utilities section);
- timing of rate decisions (refer to the Utilities and Regulatory Matters sections);
- the TXU Europe Settlement (refer to TXU Europe Settlement section); and
- changes in share appreciation rights expense due to changes in Canadian Utilities Limited Class A 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, 2005, increased by \$43.3 million to \$680.3 million, primarily due to:

- higher revenues in ATCO Power’s Alberta generating plants due to higher Alberta Power Pool prices;
- 2004 impact of 2004 General Rate Application adjustments for ATCO Gas related to the refund of deferred income taxes; and
- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities.

This increase was partially offset by:

- lower availability in the Barking generating plant due to a planned maintenance outage in September through November 2005;
- lower activity in ATCO Frontec projects; and
- lower natural gas fuel purchases recovered on a “no margin” basis at ATCO Power’s Barking generating plant.

Revenues for the year ended December 31, 2005, decreased by \$495.6 million to \$2,515.8 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses in May 2004;
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream; and
- lower natural gas volumes purchased for ATCO Pipelines’ customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue).

This decrease was partially offset by:

- higher prices for natural gas liquids in ATCO Midstream;
- increased business activity, including work for new customers, in ATCO I-Tek;
- higher revenues in ATCO Power’s Alberta generating plants due to higher Alberta Power Pool prices;
- improved merchant performance in ATCO Power’s U.K. operations; and
- a full year of operations at ATCO Power’s 580 megawatt Brighton Beach generating plant commissioned in July 2004.

Earnings attributable to Class A and Class B shares for the three months ended December 31, 2005, decreased by \$1.2 million (\$0.01 per share) to \$89.1 million (\$0.70 per share), primarily due to:

- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream; and
- higher costs not recovered in ATCO Gas in 2005. In May 2005, ATCO Gas submitted a general rate application with the AEUB for the 2005, 2006 and 2007 test years. In August 2005, the AEUB approved interim refundable rates which recognized only 28% of the increased operating costs and rate base additions requested in the original application. On January 27, 2006, ATCO Gas received an AEUB decision which did not materially change the earnings based on the 2005 interim rates (the “ATCO Gas Decision”). The final impact of the decision will not be known until two subsequent regulatory processes are finalized (refer to Regulatory Matters – ATCO Gas section).

This decrease was partially offset by:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales in the Alberta market; and
- higher storage earnings due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream.

Earnings attributable to Class A and Class B shares for the year ended December 31, 2005, were \$265.6 million (\$2.09 per share). Earnings for 2004 were \$253.9 million (\$2.00 per share), **excluding** the \$55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses in May 2004. Earnings for the year ended December 31, 2004, **including** the impact of the Transfer of the Retail Energy Supply Businesses, were \$309.0 million (\$2.44 per share).

Earnings attributable to Class A and Class B shares for the year ended December 31, 2005, **excluding** the impact of the Transfer of the Retail Energy Supply Businesses, increased by \$11.7 million (\$0.09 per share), primarily due to:

- higher storage earnings due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream; and
- the TXU Europe Settlement (refer to TXU Europe Settlement section).

This increase was partially offset by:

- increased 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, 2004;
- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream;
- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section); and
- warmer temperatures in ATCO Gas.

Return on common equity was 12.2% in 2005.

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, 2005, increased by \$27.7 million to \$399.0 million, primarily due to:

- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities; and
- higher natural gas liquids shrinkage costs in ATCO Midstream due to higher natural gas prices.

This increase was partially offset by:

- 2004 one time impact of finalization of natural gas supply costs in ATCO Gas related to the Transfer of the Retail Energy Supply Businesses;
- lower business activity in ATCO Frontec; and
- lower natural gas volumes purchased for ATCO Pipelines' customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue).

Operating expenses for the year ended December 31, 2005, decreased by \$553.6 million to \$1,553.9 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a "no-margin" basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses in May 2004; and
- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream;
- higher fuel costs at ATCO Power's Barking generating plant due to natural gas fuel purchases recovered on a "no margin" basis; and
- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities.

Depreciation and amortization expenses for the three months ended December 31, 2005, increased by \$3.3 million to \$84.5 million, primarily due to:

- capital additions in 2005 and 2004.

Depreciation and amortization expenses for the year ended December 31, 2005, increased by \$20.0 million to \$311.5 million, primarily due to:

- capital additions in 2005 and 2004.

Interest expense for the three months ended December 31, 2005, decreased by \$1.5 million to \$51.4 million, primarily due to:

- lower interest rates on new financings issued to retire long term debt maturing in 2005; and
- retirement of non-recourse financings in 2005 and 2004.

This decrease was partially offset by:

- interest on new financings issued in 2005 and 2004 to fund capital expenditures in Utilities operations.

Interest expense for the year ended December 31, 2005, increased by \$6.3 million to \$210.0 million, primarily due to:

- interest on new financings issued in 2005 and 2004 to fund capital expenditures in Utilities operations; and
- interest on non-recourse financings for ATCO Power's Brighton Beach generating plant commissioned in July 2004.

This increase was partially offset by:

- lower interest rates on new financings issued to retire long term debt maturing in 2005; and
- retirement of non-recourse financings in 2005 and 2004.

Interest and other income for the three months ended December 31, 2005, increased by \$0.2 million to \$10.6 million, primarily due to:

- interest income on higher cash balances.

Interest and other income for the year ended December 31, 2005, increased by \$5.8 million to \$36.6 million, primarily due to:

- interest income on higher cash balances; and
- the recovery of ATCO Electric's carrying costs and interest associated with the AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in deferred income taxes (refer to Regulatory Matters – ATCO Electric section).

Income taxes for the three months ended December 31, 2005, increased by \$15.2 million to \$58.0 million, primarily due to:

- favorable tax adjustment in 2004 for ATCO Gas resulting from a change in income tax methodology as directed by the AEUB in its decision respecting ATCO Gas' 2003/2004 General Rate Application.

Income taxes for the year ended December 31, 2005, **including** the \$8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses in May 2004, increased by \$17.6 million to \$175.6 million.

Income taxes for the year ended December 31, 2005, **excluding** the \$8.2 million of income taxes resulting from the Transfer of the Retail Energy Supply Businesses, increased by \$25.8 million to \$175.6 million, primarily due to:

- higher earnings; and
- favorable tax adjustment in 2004 for ATCO Gas resulting from a change in income tax methodology as directed by the AEUB in its decision respecting ATCO Gas' 2003/2004 General Rate Application.

Segmented Information

Segmented revenues for the three months and the year ended December 31, 2005, were as follows:

(\$ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2005	2004	2005	2004
	<i>(unaudited)</i>			
Utilities (1).....	305.5	297.9	1,195.9	1,789.8
Power Generation	208.2	183.9	761.7	653.2
Global Enterprises (2).....	202.7	188.2	688.0	920.1
Corporate and Other	3.2	3.9	12.4	11.6
Intersegment eliminations.....	(39.3)	(36.9)	(142.2)	(363.3)
Total.....	680.3	637.0	2,515.8	3,011.4

Notes:

- (1) 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.
- (2) Subsequent to the Transfer of the Retail Energy Supply Businesses on May 4, 2004, ATCO Midstream purchased lower volumes of natural gas for ATCO Gas.

Segmented earnings attributable to Class A and Class B shares for the three months and the year ended December 31, 2005, were as follows:

(\$ Millions)	For the Three Months Ended December 31		For the Year Ended December 31	
	2005	2004	2005	2004
	<i>(unaudited)</i>			
Utilities (1).....	32.5	38.5	106.0	168.7
Power Generation	36.1	24.1	103.0	80.0
Global Enterprises	28.2	30.8	81.0	72.1
Corporate and Other	(7.5)	(3.6)	(23.5)	(14.8)
Intersegment eliminations.....	(0.2)	0.5	(0.9)	3.0
Total.....	89.1	90.3	265.6	309.0

Note:

- (1) The December 31, 2004, earnings include \$55.1 million (earnings per share of \$0.44) and (diluted earnings per share of \$0.43) resulting from the Transfer of the Retail Energy Supply Businesses.

Utilities

Revenues from the Utilities Business Group for the three months ended December 31, 2005, increased by \$7.6 million to \$305.5 million, primarily due to:

- 2004 impact of 2004 General Rate Application adjustments for ATCO Gas related to the refund of deferred income taxes;
- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities; and
- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section).

This increase was partially offset by:

- reduced recoveries of natural gas costs and lower storage revenues as ATCO Gas is no longer storing or selling natural gas from its Carbon natural gas storage facility. ATCO Gas has leased the entire storage

capacity of the facility to ATCO Midstream for the period April 1, 2005 to March 31, 2006.

Temperatures in ATCO Gas for the three months ended December 31, 2005, were 14.1% warmer than normal, compared to 9.8% warmer than normal for the corresponding period in 2004.

Revenues from the Utilities Business Group for the year ended December 31, 2005, decreased by \$593.9 million to \$1,195.9 million, primarily due to:

- lower sales of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses in May 2004;
- reduced recoveries of natural gas costs and lower storage revenues as ATCO Gas is no longer storing or selling natural gas from its Carbon natural gas storage facility. ATCO Gas has leased the entire storage capacity of the facility to ATCO Midstream for the period April 1, 2005 to March 31, 2006; and
- lower natural gas volumes purchased for ATCO Pipelines’ customers as a result of customers moving from sales service (commodity and transportation revenues) to transportation service only contracts (transportation revenue).

This decrease was partially offset by:

- higher franchise fees collected by ATCO Gas on behalf of cities and municipalities;
- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section);
- 2004 impact of 2004 General Rate Application adjustments for ATCO Gas related to the refund of deferred income taxes; and
- higher transmission charges recovered from customers in ATCO Gas.

Temperatures in ATCO Gas in 2005 were 7.8% warmer than normal, compared to 3.0% warmer than normal in 2004.

Earnings for the three months ended December 31, 2005, decreased by \$6.0 million to \$32.5 million, primarily due to:

- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section); and
- warmer temperatures in ATCO Gas.

Earnings for the year ended December 31, 2005, were \$106.0 million. Earnings for 2004 were \$113.6 million, **excluding** the \$55.1 million after-tax gain on the Transfer of the Retail Energy Supply Businesses in May 2004. Earnings for the year ended December 31, 2004, **including** the impact of the Transfer of the Retail Energy Supply Businesses, were \$168.7 million.

Earnings for the year ended December 31, 2005, **excluding** the impact of the Transfer of the Retail Energy Supply Businesses, decreased by \$7.6 million, primarily due to:

- impact of the ATCO Gas Decision (refer to Regulatory Matters – ATCO Gas section); and
- warmer temperatures in ATCO Gas.

This decrease was partially offset by:

- impact of the AEUB decision adjusting the 2001 and 2002 revenue requirements for changes in deferred income taxes recorded in ATCO Electric (refer to Regulatory Matters – ATCO Electric section).

Operating expenses for the year ended December 31, 2005, decreased by \$611.7 million to \$716.9 million, primarily due to:

- lower costs of electricity and natural gas purchased for customers on a “no-margin” basis by ATCO Electric and ATCO Gas due to the Transfer of the Retail Energy Supply Businesses in May 2004.

The decrease was partially offset by:

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

Power Generation

Revenues from the Power Generation Business Group for the three months ended December 31, 2005, increased by \$24.3 million to \$208.2 million, primarily due to:

- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices;
- higher revenues at ATCO Power's Osborne generating plant due to a planned maintenance outage in the fourth quarter of 2004; and
- improved merchant performance in ATCO Power's U.K. operations.

This increase was partially offset by:

- lower availability in ATCO Power's Barking generating plant due to a planned maintenance outage in September through November 2005; and
- lower natural gas fuel purchases recovered on a "no margin" basis at ATCO Power's Barking generating plant.

Revenues from the Power Generation Business Group for the year ended December 31, 2005, increased by \$108.5 million to \$761.7 million, primarily due to:

- higher revenues in ATCO Power's Alberta generating plants due to higher Alberta Power Pool prices;
- improved merchant performance in ATCO Power's U.K. operations; and
- a full year of operations at ATCO Power's 580 megawatt Brighton Beach generating plant commissioned in July 2004.

This increase was partially offset by:

- lower availability in ATCO Power's Barking generating plant due to a planned maintenance outage in September through November 2005.

Earnings for the three months ended December 31, 2005, increased by \$12.0 million to \$36.1 million, primarily due to:

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales in the Alberta market;
- a settlement with a supplier for damages due to equipment defects in ATCO Power's U.K. operations; and
- improved merchant performance in ATCO Power's U.K. operations.

This increase was partially offset by:

- lower availability in ATCO Power's Barking generating plant due to a planned maintenance outage in September through November 2005.

Alberta Power Pool electricity prices for the three months ended December 31, 2005, averaged \$117.07 per megawatt hour, compared to average prices of \$55.07 per megawatt hour for the corresponding period in 2004. Natural gas prices for the three months ended December 31, 2005, averaged \$10.77 per gigajoule, compared to average prices of \$6.16 per gigajoule for the corresponding period in 2004. The consequence of these changes in electricity and natural gas prices was an average spark spread of \$36.31 per megawatt hour for the three months ended December 31, 2005, compared to \$8.87 per megawatt hour for the corresponding period in 2004.

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 300 megawatts of plant capacity owned in Alberta by ATCO Power out of a total world wide owned capacity of approximately 1,318 megawatts.

Earnings for the year ended December 31, 2005, increased by \$23.0 million to \$103.0 million, primarily due to:

- the TXU Europe Settlement (refer to TXU Europe Settlement section);
- improved merchant performance in ATCO Power's U.K. operations;
- a full year of operations at ATCO Power's 580 megawatt Brighton Beach generating plant commissioned in July 2004; and

- higher earnings in ATCO Power's Alberta generating plants due to higher spark spreads realized on sales in the Alberta market.

This increase was partially offset by:

- lower availability in ATCO Power's Barking generating plant due to a planned maintenance outage in September through November 2005.

Alberta Power Pool electricity prices in 2005, averaged \$70.36 per megawatt hour, compared to average prices of \$54.59 per megawatt hour in 2004. Natural gas prices in 2005, averaged \$8.27 per gigajoule, compared to average prices of \$6.19 per gigajoule in 2004. The consequence of these changes in electricity and natural gas prices was an average spark spread of \$8.32 per megawatt hour in 2005, compared to \$8.16 per megawatt hour in 2004.

Operating expenses for the year ended December 31, 2005, increased by \$68.0 million to \$414.7 million, primarily due to:

- higher fuel costs at ATCO Power's Barking generating plant due to natural gas fuel purchases recovered on a "no margin" basis; and
- higher fuel costs at ATCO Power's Alberta gas fired plants due to higher natural gas prices.

At December 31, 2005, all of ATCO Power's non-regulated independent generating plants were in service.

During the three months ended December 31, 2005, Alberta Power (2000)'s **deferred availability incentive** account increased by \$14.4 million to \$59.7 million. The increase was due to additional availability incentives received for improved plant availability. During the three months ended December 31, 2005, the amortization of deferred availability incentives, recorded in revenues, increased by \$0.7 million to \$2.7 million as compared to the same period in 2004.

During the year ended December 31, 2005, Alberta Power (2000)'s **deferred availability incentive** account increased by \$13.6 million to \$59.7 million. The increase was due to additional availability incentives received for plant availability in excess of planned outages and amortization. During the year ended December 31, 2005, the amortization of deferred availability incentives, recorded in revenues, increased by \$1.3 million to \$8.9 million as compared to 2004.

Global Enterprises

Revenues from the Global Enterprises Business Group for the three months ended December 31, 2005, increased by \$14.5 million to \$202.7 million, primarily due to:

- higher storage revenues due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream.

This increase was partially offset by:

- lower activity in ATCO Frontec projects; and
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream.

Revenues from the Global Enterprises Business Group for the year ended December 31, 2005, decreased by \$232.1 million to \$688.0 million, primarily due to:

- lower volumes of natural gas purchased in ATCO Midstream for ATCO Gas as a result of the Transfer of the Retail Energy Supply Businesses; and
- lower volumes of natural gas purchased and resold for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher prices for natural gas liquids in ATCO Midstream;
- higher storage revenues due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream; and
- increased business activity, including work for new customers, in ATCO I-Tek.

Earnings for the three months ended December 31, 2005, decreased by \$2.6 million to \$28.2 million, primarily due to:

- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher storage earnings due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream.

Earnings for the year ended December 31, 2005, increased by \$8.9 million to \$81.0 million, primarily due to:

- higher storage earnings due to higher capacity leased and the timing and demand of storage capacity sold in ATCO Midstream; and
- increased business activity, including work for new customers, in ATCO I-Tek.

This increase was partially offset by:

- lower volumes, and higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream.

Operating expenses for the year ended December 31, 2005, decreased by \$250.3 million to \$538.8 million, primarily due to:

- lower volumes of natural gas purchased in ATCO Midstream for ATCO Gas as a result of the Transfer of the Retail Energy Supply Businesses; and
- lower volumes of natural gas purchased for natural gas liquids extraction in ATCO Midstream.

This decrease was partially offset by:

- higher shrinkage and power costs for natural gas liquids extraction in ATCO Midstream.

Corporate and Other

Earnings for the three months ended December 31, 2005 decreased by \$3.9 million to \$(7.5) million, primarily due to:

- increased administrative costs; and
- increased share appreciation rights expense due to changes in Canadian Utilities Limited Class A share and ATCO Ltd. Class I Non-Voting Share prices since September 30, 2005.

Earnings for the year ended December 31, 2005 decreased by \$8.7 million to \$(23.5) million, primarily due to:

- increased 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, 2004; and
- increased administrative costs.

REGULATORY MATTERS

Regulated operations are conducted by 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), all of which are wholly owned subsidiaries of the Corporation's wholly owned subsidiary, CU Inc.

In July 2004, the AEUB issued its generic cost of capital decision. The decision established a standardized approach for each utility company regulated by the AEUB for determining the rate of return on common equity based upon a return of 9.60% on common equity. This rate of return is adjusted annually by 75% of the change in long term Government of Canada bond yield as forecast in the November Consensus Forecast, adjusted for the average difference between the 10 year and 30 year Government of Canada bond yields for the month of October as reported in the National Post. This adjustment mechanism is the same as the National Energy Board uses in determining its formula based rate of return. The AEUB will undertake a review of this mechanism for the year 2009 or if the rate of return resulting from the formula is less than 7.6% or greater than 11.6%. The AEUB also noted that any party, at

any time, could petition for a review of the adjustment formula if that party can demonstrate a material change in facts or circumstances.

The decision also established the appropriate capital structure for each utility regulated by the AEUB. The AEUB determined that any proposed changes to the approved capital structure which result from a material change in the investment risk of a utility will be addressed at utility specific rate applications.

In November 2004, the AEUB announced a generic return on common equity of 9.50% for 2005 and in November 2005 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.

In July 2004, ATCO Gas and ATCO Electric filed applications with the AEUB addressing the impact on the 2003 and 2004 revenue requirements of the Transfer of the Retail Energy Supply Businesses to DEML and the customer care volume forecast for services provided by ATCO I-Tek Business Services for 2003 and 2004. In April and May 2005, the AEUB issued decisions which resulted in an increase to revenues and earnings of \$2.4 million and \$1.6 million, respectively.

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 is also a party to this filing as the concerns are common to all three utilities. This filing included evidence regarding the appropriate ratemaking approach in the determination of utility revenue requirements as well as treatment of pension costs, executive compensation, head office rent expense and the continued use of preferred shares as a form of financing for the three utilities. The AEUB is expected to hear this filing in May 2006 and a decision is expected in the fourth quarter of 2006.

ATCO Electric

In May 2005, ATCO Electric filed a general tariff application with the AEUB for the 2005 and 2006 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 March 2006. In May and June 2005, ATCO Electric filed applications requesting interim refundable rates for distribution and transmission operations, pending the AEUB's decision on the general tariff application. On July 14, 2005, ATCO Electric received a decision from the AEUB approving its requested interim refundable rates for distribution operations. On September 7, 2005, ATCO Electric received a decision from the AEUB approving an interim refundable rate increase of \$5.0 million for transmission operations. Revenues associated with these interim refundable rates were recorded in 2005.

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 deferred income taxes recorded. In November 2002, ATCO Electric filed a review and variance application of the August 2002 decision with the AEUB. In May 2005, the AEUB changed its August 2002 decision and allowed ATCO Electric to increase its revenues and earnings by \$4.6 million.

ATCO Gas

On January 27, 2006, ATCO Gas received a decision on its general rate application which was filed with the AEUB in May 2005 for the 2005, 2006 and 2007 test years. The decision establishes the amount of revenue ATCO Gas can recover through distribution rates for natural gas distribution service to its customers over the period of 2005 to 2007. In May 2005, ATCO Gas submitted a general rate application with the AEUB for the 2005, 2006 and 2007 test years. In August 2005, the AEUB approved interim refundable rates which recognized only 28% of the increased operating costs and rate base additions requested in the original application. On January 27, 2006, ATCO Gas received an AEUB decision which did not materially change the earnings based on the 2005 interim rates. The final impact of the decision will not be known until two subsequent regulatory processes are finalized. There will be no immediate impact on the ATCO Gas distribution rates as interim rates will continue until final rates are decided by the AEUB in late 2006 or early 2007. The general rate application decision approved a return on common equity as determined by the AEUB's standardized rate of return methodology. The rate of return on common equity is 9.5% in 2005, 8.93% in 2006, and is yet to be determined for 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) and allocated \$4.1 million of the proceeds to customers and \$1.8 million to ATCO Gas. In January 2004, the Alberta Court of Appeal overturned this decision and directed the AEUB to allocate \$5.4 million of the proceeds to ATCO Gas. The City of Calgary has appealed this decision to the Supreme Court of Canada, which has also granted ATCO Gas leave to cross-appeal the decision. The Supreme Court of Canada heard the appeal on May 11, 2005 and on February 9, 2006 rendered its decision. The Supreme Court dismissed the City of Calgary's appeal and allowed ATCO Gas' cross-appeal. The decision will not impact the 2005 earnings of ATCO Gas, as the Supreme Court has directed the AEUB to issue a new decision in accordance with the Supreme Court's ruling. Net proceeds totaling \$4.1 million from the sale are being held pending AEUB approval. It is anticipated that the AEUB will issue a new decision before the end of the first quarter of 2006.

In March 2004, the AEUB directed ATCO Gas to continue to reserve for the benefit of utility customers 16.7 petajoules of storage capacity at its Carbon natural gas storage facility for the 2004/2005 storage year, which ended on March 31, 2005, and allowed ATCO Midstream to continue to utilize the remaining uncontracted capacity at a rate of \$0.45 per gigajoule, up from \$0.41 per gigajoule. ATCO Gas was granted leave to appeal this AEUB decision to the Alberta Court of Appeal. On June 17, 2005 the appeal was dismissed. On September 16, 2005, ATCO Gas filed for leave to appeal the Alberta Court of Appeal's decision to the Supreme Court of Canada. The leave to appeal was denied on January 19, 2006.

In July 2004, the AEUB initiated a written process to consider its role in regulating the operations of the Carbon natural gas storage facility. On June 15, 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 has filed for leave to appeal the decision with the Alberta Court of Appeal. On October 3, 2005, the AEUB established processes to review the use of the Carbon natural gas storage facility for utility purposes.

ATCO Gas' position is that the Carbon natural gas storage facility is no longer required for utility service. Accordingly, in March 2005, ATCO Gas filed a letter with the AEUB in which it withdrew all evidence previously filed by it with respect to the 2005/2006 Carbon Storage Plan, thus providing notice that none of the related costs and revenues will form part of regulated operations on or after April 1, 2005. On March 23, 2005, the AEUB issued an interim order directing ATCO Gas to maintain the Carbon natural gas storage facility in rate base and confirming a lease of the entire storage capacity to ATCO Midstream at a placeholder rate of \$0.45 per gigajoule until otherwise determined by the AEUB. ATCO Gas filed for leave to appeal the interim order on April 15, 2005.

ATCO Gas has filed an application with the AEUB to address, among other things, corrections required to historical transportation imbalances 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 revenues and earnings of \$1.8 million and \$1.2 million, respectively. The City of Calgary has filed for leave to appeal the AEUB's decision. ATCO Gas has filed a cross appeal of the AEUB's decision. The cross appeal is contingent upon the granting of the City of Calgary's leave to appeal which is scheduled to be heard in February 2006.

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 renders 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. ATCO Gas is now required to submit a filing to the AEUB to approve the allocation of the net proceeds. The net proceeds of the sale remain in trust pending AEUB approval.

ATCO Pipelines

The AEUB has announced that it will hold a hearing to address competitive issues between ATCO Pipelines and NOVA Gas Transmission Ltd. This hearing is expected to take place in 2006.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow from operations provides a substantial portion of the Corporation's cash requirements. Additional cash requirements are met externally through bank borrowings and the issuance of long term 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.

Cash flow from operations for the three months ended December 31, 2005, increased by \$23.4 million to \$187.8 million, primarily due to:

- increased cash flow after removal of non-cash adjustments.

Cash flow from operations for the year ended December 31, 2005, increased by \$121.0 million to \$659.3 million, primarily due to:

- the TXU Europe Settlement (refer to TXU Europe Settlement section);
- higher earnings; and
- increased deferred availability incentives in Alberta Power (2000), primarily due to availability incentive payments received for improved plant availability.

Investing for the three months ended December 31, 2005, increased by \$35.1 million to \$160.3 million, primarily due to:

- increased capital expenditures; and
- changes in non-current deferred electricity costs.

This increase was partially offset by:

- changes in non-cash working capital in respect of investing activities.

Capital expenditures for the three months ended December 31, 2005, increased by \$32.1 million to \$181.2 million, primarily due to:

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

This increase was partially offset by:

- lower investment in non-regulated power generation projects

Investing for the year ended December 31, 2005, increased by \$1.1 million to \$470.4 million, primarily due to:

- changes in non-current deferred electricity costs;
- changes in non-cash working capital in respect of investing activities; and
- lower contributions by utility customers for extensions to plant.

This increase was partially offset by:

- proceeds from the Transfer of the Retail Energy Supply Businesses; and
- lower capital expenditures.

Capital expenditures for the year ended December 31, 2005, decreased by \$8.8 million to \$526.7 million, primarily due to:

- lower investment in power generation and regulated electric projects.

This decrease was partially offset by:

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

During the three months ended December 31, 2005, the Corporation **issued**:

- \$185.0 million of 5.183% Debentures due November 21, 2035.

During the three months ended December 31, 2005, the Corporation **redeemed**:

- \$35.4 million of long term debt; and
- \$9.1 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of \$140.5 million.

During the year ended December 31, 2005, the Corporation **issued**:

- \$185.0 million of 5.183% Debentures due November 21, 2035; and
- \$37.0 million of other long term debt.

During the year ended December 31, 2005, the Corporation **redeemed**:

- \$125.0 million of 8.43% Debentures 1995 Series;
- \$42.1 million of other long term debt; and
- \$54.3 million of non-recourse long term debt.

These changes resulted in a **net debt increase** of \$0.6 million.

Foreign currency translation for the three months ended December 31, 2005, increased the Corporation's cash position by \$0.3 million to \$0.2 million.

Foreign currency translation for the year ended December 31, 2005, decreased the Corporation's cash position by \$10.7 million to (\$11.2) million, primarily as a result of:

- strengthening of the Canadian dollar which resulted in a reduction in the value of cash balances denominated in U.K. pounds when translated into Canadian dollars.

Capital expenditures to maintain capacity, meet planned growth and fund future development activities are expected to be approximately \$575 million in 2006. These expenditures are uncommitted and relate primarily to utility operations.

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

Contractual Obligations	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
(\$ Millions)					
Long term debt	2,231.0	175.0	166.0	250.0	1,640.0
Non-recourse long term debt	730.8	57.0	127.9	147.2	398.7
Operating leases.....	63.2	15.9	27.6	12.7	7.0
Purchase obligations:					
ATCO Gas natural gas purchase contracts (1)	9.0	1.1	2.2	2.2	3.5
Alberta Power (2000) coal purchase contracts (2)	656.8	47.3	98.9	105.0	405.6
Alberta Power (2000) capital expenditures (3)	8.8	8.8	-	-	-
ATCO Power natural gas fuel supply contracts (4)	289.2	46.3	101.8	100.0	41.1
ATCO Power operating and maintenance agreements (5).....	166.6	14.8	35.0	33.5	83.3
ATCO Power capital expenditures (6).....	1.8	1.8	-	-	-
ATCO Electric capital expenditures (7).....	19.6	19.1	0.5	-	-
Other	13.7	13.7	-	-	-
Total.....	4,190.5	400.8	559.9	650.6	2,579.2

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, 2005, 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) Alberta Power (2000) has entered into contracts with suppliers to improve operating efficiency at certain of its generating plants.
- (4) ATCO Power has various contracts to purchase natural gas for 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.
- (5) ATCO Power has various contracts with suppliers to provide operating and maintenance services at certain of its generating plants.
- (6) ATCO Power has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.
- (7) ATCO Electric has entered into various contracts to purchase goods and services with respect to its capital expenditure programs.

At December 31, 2005, 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	11.9	314.1
Short term committed	600.0	-	600.0
Uncommitted	69.1	8.3	60.8
Total.....	995.1	20.2	974.9

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

Current and long term future income tax liabilities of \$204.4 million at December 31, 2005, 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, 2004, 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, 2005. Over the life of the bid, 289,800 shares were purchased, of which 256,800 were purchased in 2004 and 33,000 were purchased in 2005. 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 will expire on May 19, 2006. From May 20, 2005, to February 22, 2006, 195,600 shares have been purchased, all of which were purchased in 2005.

It is the policy of the Corporation to **pay dividends** quarterly on its Class A and Class B shares. In 2005, the Corporation increased the dividends on Class A and Class B shares by \$0.04 per share, the same increase as in 2004. 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 2006, the **quarterly dividend** payment has been increased by \$0.01 to \$0.285 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 January 16, 2004, CU Inc. filed a base shelf prospectus which permits CU Inc. to issue up to an aggregate of \$750.0 million of debentures over the twenty-five month life of the prospectus.

- On January 23, 2004, CU Inc. issued \$180.0 million of 5.432% Debentures due January 23, 2019, at a price of 100 to yield 5.432%. The proceeds of the issue were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.

- On November 18, 2004, CU Inc. issued \$100.0 million of 5.096% Debentures due November 18, 2014, at a price of 100 to yield 5.096% and \$200.0 million of 5.896% Debentures due November 20, 2034, at a price of 100 to yield 5.896%. The proceeds of the issues were advanced to ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water and used to fund capital expenditures, repay indebtedness and for general corporate purposes.
- On November 21, 2005, CU Inc. issued \$185.0 million of 5.183% Debentures due November 21, 2035, at a price of 100 to yield 5.183%. The proceeds of the issue 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 21, 2006, the Corporation had outstanding 82,939,286 Class A shares and 44,016,284 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 the 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 20,000,000 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, 2,747,200 Class A shares are available for issuance at December 31, 2005. 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 21, 2006, options to purchase 1,471,400 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 18 to the consolidated financial statements.

BUSINESS RISKS

On February 16, 2005, the Kyoto Protocol came into effect. The Corporation is unable to determine what impact the protocol may have on its operations as the Government of Canada has not yet provided industry specific details for its 2005 Climate Change Plan. It is anticipated that the Corporation's power purchase arrangements ("PPA's") relating to its coal-fired generating plants will allow the Corporation to recover any increased costs associated with the implementation of the protocol.

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, 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.

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 \$11.4 million.

Transfer of the Retail Energy Supply Businesses

Although ATCO Gas and ATCO Electric have 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 in respect of the ongoing relationships to DEML contemplated under the transaction agreements.

As a result of the agreements with DEML, ATCO Gas and ATCO Electric are no longer involved in arranging for the supply and sale of natural gas and electricity to customers, but will continue to own the assets and provide the transportation and distribution services under AEUB approved rates that provide for a recovery of costs of service and a fair return.

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 expiry of the PPA's. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant and 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, 2005, the Corporation had recorded \$59.7 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.

As a result of unprecedented drought conditions, the water levels in the cooling pond used by the Battle River generating plant in its production of electricity had fallen to all-time lows in early 2003 and in 2004 and the Corporation was forced to curtail production of electricity. Water levels in the cooling pond have returned to normal for this time of year and there has been no curtailment of production in 2005 or to date in 2006.

Alberta Environment plans to implement mercury emission standards for coal-fired generating plants through a new provincial regulation that is expected to be in place by March 2006. Owners of coal-fired generating plants are required to submit proposals on capturing at least 70% of the mercury in the coal burned in their plants by March 2007. The proposals for mercury emission reduction must be implemented by 2010. 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.

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.

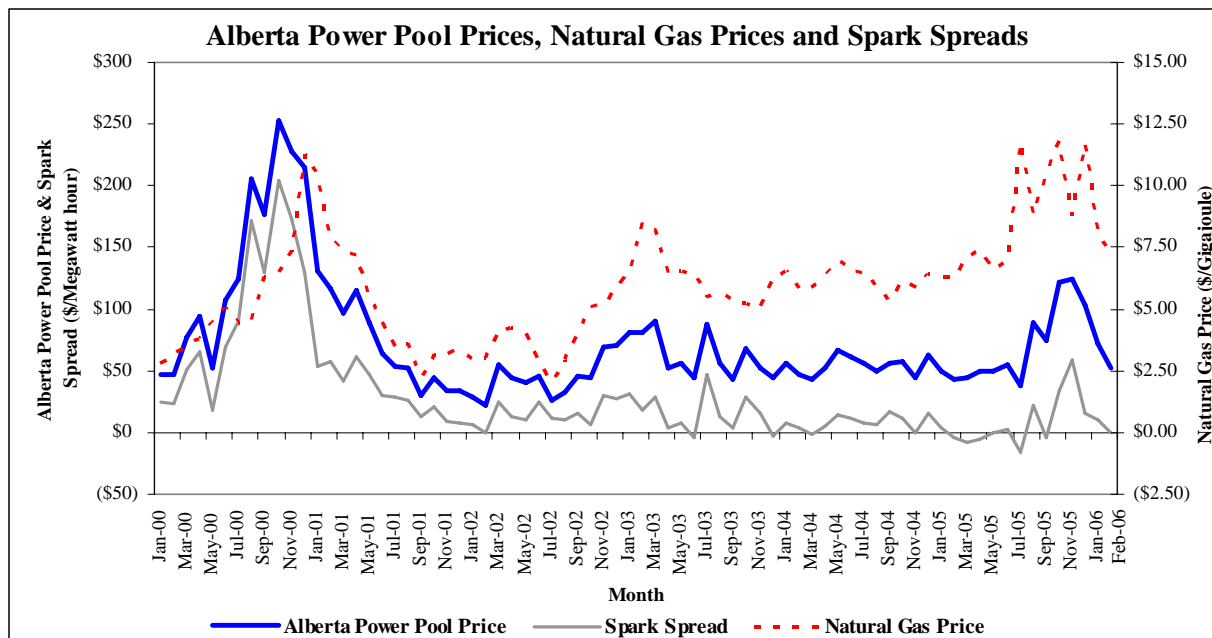
ATCO Power

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 2005, 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 2006, 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 strong 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 2006.



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 the market has experienced an increase in electricity prices due to the increased world prices for natural gas. 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 rising 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, 2005, are described in Note 11 to the consolidated financial statements. 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.

CONTINGENCIES

The Government of Canada has 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 without merit 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

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

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, 2005, refer to Note 20 to the consolidated financial statements.

OFF-BALANCE SHEET ARRANGEMENTS

Unrecorded future income tax liabilities of the regulated operations amounted to \$171.3 million at December 31, 2005. This balance includes \$28.2 million in respect of Alberta Power (2000)'s generating plants, which will be recovered through future payments received in respect of the PPA's. The remainder, amounting to \$143.1 million, is expected to be recovered from utility customers through inclusion in future rates. There are tax loss carryforwards of \$0.7 million for which no tax benefit has been recorded. These losses begin to expire in 2010. For additional information on the Corporation's unrecorded future income tax liabilities, refer to Note 7 to the consolidated financial statements.

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, 2005, the Corporation had recorded \$59.7 million of deferred availability incentives. The amortization of deferred availability incentives, which was recorded in revenues, amounted to \$8.9 million in 2005.

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 \$4.3 million, whereas the low case scenario would have resulted in lower revenues of approximately \$2.2 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 at the beginning of the year 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 5.9% at the beginning of 2005, resulted in an expected long term rate of return of 6.9% for 2005. 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 four years, from 8.1% in 2001 to 6.9% in the year ended December 31, 2005. 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 four year period, from 6.9% at the end of 2001 to 5.1% at the end of 2005. 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, 2005.

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, 2005, are as follows: for drug costs, 9.3% starting in 2005 grading down over 8 years to 4.5%, and for other medical and dental costs, 4.0% for 2005 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 2005 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.

	2005 Pension Benefit Plans		2005 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost (Income)	Accrued Benefit Obligation	Benefit Plan Cost (Income)
	(\$ Millions)			
Expected long term rate of return on plan assets				
1% increase (1)	-	(3.2)	-	-
1% decrease (1).....	-	3.2	-	-
Liability discount rate				
1% increase (1)	(57.7)	(4.9)	(3.3)	(0.3)
1% decrease (1).....	74.0	6.3	4.1	0.4
Future compensation rate				
1% increase (1)	18.1	2.5	-	-
1% decrease (1).....	(15.6)	(2.1)	-	-
Long term inflation rate				
1% increase (1)(2)(3).....	25.0	3.2	3.7	0.6
1% decrease (1) (3).....	(42.7)	(5.2)	(3.0)	(0.5)

Notes:

- (1) Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost (income), 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

During 2005, the Corporation adopted the recommendations of the Canadian Institute of Chartered Accountants (“CICA”) pertaining to the consolidation of variable interest entities and lease arrangements. None of these policies had any material effect on the Corporation’s financial statements. These changes in accounting policy are discussed in Note 1 to the consolidated financial statements.

Effective December 31, 2005, the Corporation retroactively adopted the CICA guideline pertaining to the disclosure and presentation of information by entities subject to rate regulation. This guideline no longer permits the netting of accrued and regulatory pension and other post employment benefits assets and liabilities, with the result that the Corporation's total assets and liabilities reported in 2004 increased by \$154.4 million. This change in presentation had no effect on the Corporation's earnings and earnings per share or cash flows. Accounting for rate regulated operations is described in Note 2 to the consolidated financial statements.

February 22, 2006