



CANADIAN UTILITIES LIMITED
An **ATCO** Company

MANAGEMENT'S DISCUSSION AND ANALYSIS

**FOR THE YEAR ENDED
DECEMBER 31, 2009**

CANADIAN UTILITIES LIMITED
Management's Discussion and Analysis (MD&A)
For the Year Ended December 31, 2009

This MD&A should be read in conjunction with the Corporation's unaudited consolidated financial statements for the three months ended December 31, 2009, and the audited consolidated financial statements for the year ended December 31, 2009. This MD&A is dated February 17, 2010. Additional information relating to the Corporation, including the Corporation's annual information form, is available on SEDAR at www.sedar.com.

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Glossary

Adjusted Earnings means earnings attributable to Class A and Class B Shares after adjustment for items that are not in the normal course of business or day-to-day operations. These items are usually of a non-recurring or one-time nature. Refer to Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section for a description of these items (non-GAAP item).

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

AESO means the Alberta Electric System Operator.

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

ASL means ATCO Structures & Logistics Ltd., the company formed on July 1, 2009 through the amalgamation of ATCO Structures and ATCO Frontec.

ATCO Energy Solutions means ATCO Energy Solutions Ltd.

ATCO Frontec means ATCO Frontec Corp., the wholly-owned subsidiary of Canadian Utilities Limited which amalgamated with ATCO Structures on July 1, 2009 to form ATCO Structures & Logistics Ltd.

ATCO Noise Management means ATCO Noise Management Ltd., the wholly-owned subsidiary of ATCO that became a wholly-owned subsidiary of ATCO Structures & Logistics Ltd. on July 1, 2009 and was subsequently amalgamated with ATCO Structures & Logistics Ltd. on January 1, 2010.

ATCO Structures means ATCO Structures Inc., the wholly-owned subsidiary of ATCO Ltd. which amalgamated with ATCO Frontec on July 1, 2009 to form ATCO Structures & Logistics Ltd.

AUC means the Alberta Utilities Commission.

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

Cap and Trade means a form of market emission control regulation whereby permits must be surrendered for environmental emissions. A specified number of permits are created (the cap) and distributed. These can be traded amongst market participants to meet their compliance needs. The intended result is that environmental emissions bear a cost associated with obtaining the requisite permits and that creates a financial incentive to reduce the emissions.

Carbon Rate Riders means customer rate riders that were approved in the past by the AUC to distribute net revenues related to the Carbon Natural Gas Storage Facility to customers.

Class A Shares means Class A non-voting shares of the Corporation.

Class B Shares means Class B common shares of the Corporation.

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

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

GAAP means Canadian generally accepted accounting principles.

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

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

IFRS means International Financial Reporting Standards.

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

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

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

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

OPEB means other post employment benefits, which principally include health, dental and life insurance payments for retirees and their dependants.

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

Placeholder means an AUC approved interim cost which has been included in utility customer rates pending an AUC review in a separate or future proceeding. This cost is subject to adjustment once the separate or future proceeding is completed and may result in refunds to or recoveries from customers.

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

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

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

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

U.K. means United Kingdom.

U.S. means United States of America.

Company Overview

Alberta-based Canadian Utilities Limited, an ATCO Company, with more than 5,700 employees and assets of approximately \$9.1 billion, delivers service excellence and innovative business solutions worldwide with leading companies engaged in Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation, natural gas gathering, processing, storage and liquid extraction) and Technologies (business systems solutions).

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

REALIGNMENT OF SEGMENTS

Starting in the third quarter of 2009, the Corporation reorganized its operating subsidiaries into the following segments: Utilities, Energy and Corporate & Other.

These new segments are the basis for disclosure in this MD&A. Comparative amounts for the previous year have been restated to conform to these new segments.

The **Utilities** Segment includes:

- the regulated distribution of natural gas by ATCO Gas;
- the regulated transmission of natural gas by ATCO Pipelines; and
- the regulated distribution and transmission of electric energy by ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical.

The **Energy** Segment includes:

- the non-regulated supply of electricity and cogeneration steam by ATCO Power;
- the regulated supply of electricity by Alberta Power (2000); and
- the non-regulated natural gas gathering, processing, storage and natural gas liquids extraction by ATCO Midstream.

The **Corporate & Other** Segment includes

- the Corporation's 24.5% equity investment in ATCO Structures & Logistics Ltd. (refer to Company Overview – Transaction to Combine ATCO Frontec, ATCO Structures and ATCO Noise Management section);
- the development, operation and support of information systems and technologies, and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- cash balances and commercial real estate owned by the Corporation in Alberta.

Transactions between segments are eliminated in all reporting of the Corporation's consolidated financial information. For additional information on the Corporation's segments, refer to Note 27 to the consolidated financial statements.

Prior to the third quarter of 2009, the Corporation operated in the following segments:

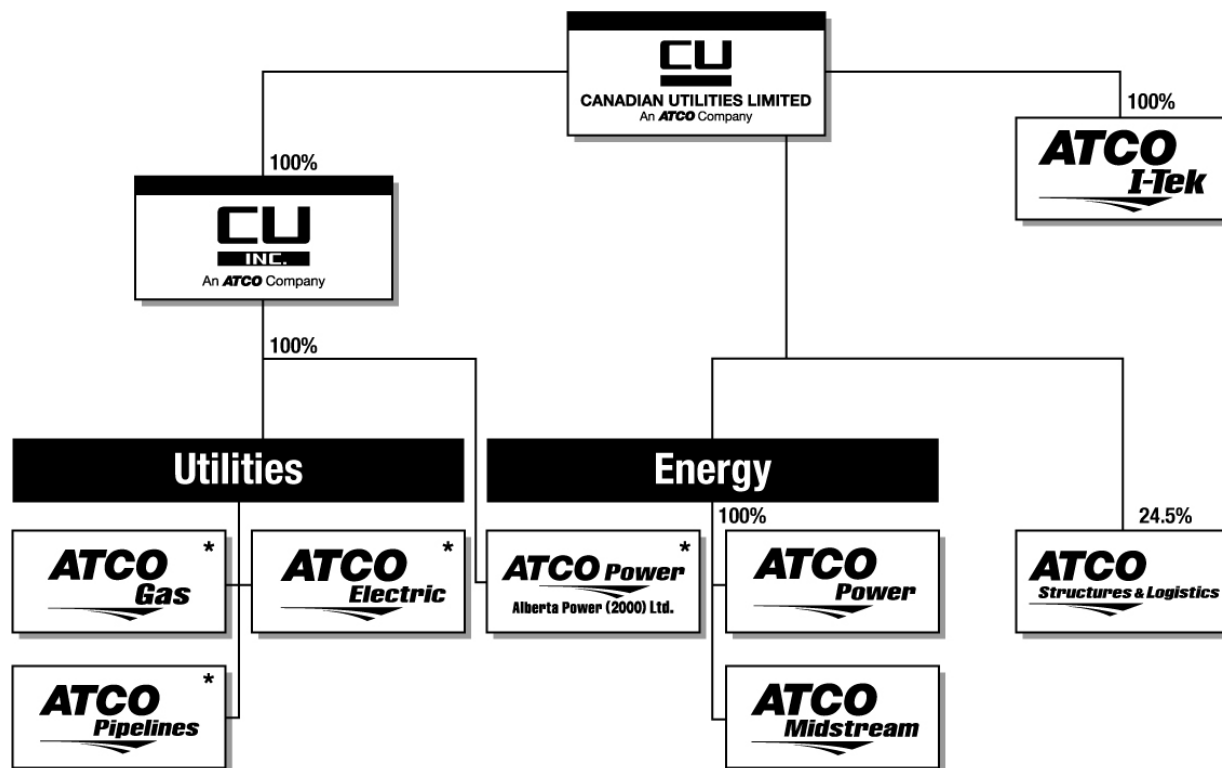
The **Utilities** Segment included ATCO Gas, ATCO Pipelines and ATCO Electric.

The **Power Generation** Segment included ATCO Power and Alberta Power (2000).

The **Global Enterprises** Segment included ATCO Midstream, ATCO Frontec and ATCO I-Tek.

The **Corporate & Other** Segment included cash balances and commercial real estate owned by the Corporation in Alberta.

Simplified Organizational Structure



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

APPOINTMENT OF NEW SENIOR VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

On November 12, 2009 the Corporation announced that Brian R. Bale had been appointed Senior Vice President and Chief Financial Officer for the Corporation effective December 1, 2009. Brian R. Bale, previously Senior Vice President, Finance and Regulatory, ATCO Gas, replaced Karen M. Watson who retired after thirty three years of service to the ATCO Group.

TRANSACTION TO COMBINE ATCO FRONTEC, ATCO STRUCTURES AND ATCO NOISE MANAGEMENT

On July 1, 2009, the Corporation and its parent ATCO Ltd. finalized a transaction combining ATCO Frontec, a wholly-owned subsidiary of the Corporation, with ATCO Structures and ATCO Noise Management, both wholly-owned subsidiaries of ATCO Ltd. (ATCO Structures & Logistics Transaction). As a result of this transaction, the Corporation and ATCO Ltd. have direct ownership interests of 24.5% and 75.5%, respectively, in the new company named ATCO Structures & Logistics Ltd. The ownership interests reflect the proportion of the respective valuations of the combined entities. The valuations were based on analysis prepared by independent financial advisors retained by the special committees of the Boards of Directors of the Corporation and ATCO Ltd.

This was a related party transaction by entities under common control and has been accounted for at the exchange amount by the Corporation; with an after tax gain for accounting purposes of \$29.6 million recorded on closing.

Prior to the ATCO Structures & Logistics Transaction, the Corporation consolidated ATCO Frontec as it was a wholly-owned subsidiary. Therefore, all revenues, expenses, assets and liabilities were recognized on a line-by-line basis in the consolidated financial statements of the Corporation for the period up to June 30, 2009.

From July 1, 2009, the Corporation records an equity accounted for investment for its 24.5% interest in ASL as it retains significant influence. This is reflected as a single line item called “Earnings from investment in ATCO Structures & Logistics” on the consolidated statement of earnings and a single line item called “Investment in ATCO Structures & Logistics” on the consolidated balance sheet. The “Investment in ATCO Structures & Logistics” is increased or decreased to include the Corporation’s share of earnings and capital transactions from July 1, 2009 onward.

As a result of the ATCO Structures & Logistics Transaction, the consolidated statement of earnings for the Corporation is comprised of a combination of revenues and expenses of ATCO Frontec from January 1 to June 30, 2009, and Earnings from investment in ATCO Structures & Logistics from July 1 to December 31, 2009. The consolidated balance sheet of the Corporation at December 31, 2009 no longer includes assets and liabilities of ATCO Frontec. The balance sheet reflects an Investment in ATCO Structures & Logistics representing the Corporation’s ownership interest in ASL. Amounts included in the consolidated statement of cash flows and consolidated statement of comprehensive earnings follow the same treatment as the consolidated statement of earnings.

ATCO Frontec was previously included in the Global Enterprises Segment. As a result of the realignment of segments (refer to Company Overview – Realignment of Segments section), all amounts relating to ATCO Frontec, for the six months ended June 30, 2009 and for the three months and year ended December 31, 2008, have been re-classified to the Corporate & Other Segment. This is consistent with the inclusion of the Corporation’s 24.5% equity investment in ASL in the Corporate & Other Segment.

The transaction allows ATCO Frontec, ATCO Structures and ATCO Noise Management to pursue a more efficient working relationship in response to changing global markets. ATCO Structures manufactured, sold and leased workforce housing and modular buildings around the world. ATCO Noise Management provided acoustical consulting services and turnkey noise control for industrial facilities, addressing environmental impact and worker exposure from noise. ATCO Frontec specialized in the rapid mobilization and delivery of site support and camp services to the resource, defence and telecommunications sectors. The new company, ASL, continues these activities and will provide customers with solutions and logistics support for facilities, catering, housing, construction and site management.

CARBON NATURAL GAS STORAGE FACILITY

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta (Carbon Facility). Since April 1, 2005, ATCO Gas has leased the entire storage capacity of the Carbon 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.

As a result of numerous regulatory and legal proceedings, ATCO Gas has removed the Carbon Facility from regulation for accounting purposes in the third quarter of 2009. Furthermore, ATCO Gas has received approval from the AUC to suspend customer rate riders (Carbon Rate Riders) that were approved in the past to distribute net revenues related to the Carbon Facility to customers.

The financial impacts of these developments recorded in the third quarter of 2009 are as follows:

- ATCO Gas removed the Carbon Facility from regulation. As a result, ATCO Gas has derecognized all previously recorded regulatory assets and liabilities relating to the Carbon Facility as these amounts are no longer recoverable from or payable to ATCO Gas' customers. The one-time impact of this discontinuation of regulatory accounting for the Carbon Facility was to increase ATCO Gas' earnings by \$1.9 million.
- ATCO Gas recognized increased revenues of \$13.8 million for the impact of the Carbon Rate Rider revenue for the period January 1, 2008 to June 30, 2008 which was previously refunded to customers and decreased revenues of \$7.6 million as a result of excluding any costs for the Carbon Facility in its 2008-2009 general rate application. The net increase to ATCO Gas' earnings as a result of this was \$4.5 million.

ATCO Gas is seeking to recover from customers additional amounts that would result in an estimated increase to its earnings of \$20.5 million, excluding interest, related to the removal of the Carbon Facility from regulation for the period April 1, 2005 to December 31, 2007. The finalization of these amounts that ATCO Gas is seeking to recover will be determined in a subsequent process scheduled to occur over the first and second quarters of 2010. As a result, these additional amounts have not yet been recognized by ATCO Gas.

For a more detailed summary of the items related to the Carbon Facility refer to Segmented Information – Utilities – Regulatory Developments – ATCO Gas – Carbon Natural Gas Storage Facility section.

FINANCIAL MARKETS

Over the last year, significant challenges have been experienced in domestic and international financial markets. These challenges have an impact on the ability of certain borrowers to finance existing operations and capital expenditure programs.

As discussed elsewhere in this MD&A, the Utilities Segment has a capital expenditure program of approximately \$3.5 billion to \$4.5 billion over the next three years. While the current financial situation has not directly impacted the Corporation's ability to fund this capital expenditure program and ongoing operations, future borrowing may be impacted by these financial markets through increased carrying costs and the ability to raise debt and preferred equity capital.

The Corporation is unable to determine what future changes in the financial markets could occur and how these changes could affect the Corporation. Deterioration in domestic and international economic activity may impact the operations of the Corporation.

COMMODITY AND ENERGY PRICES

Commodity prices, particularly oil and natural gas prices, have fallen significantly since September 2008. These lower prices have had an impact on the Corporation's operations, particularly the lower average Frac Spreads for 2009 on ATCO Midstream's NGL business and the decline in the resource sector on ASL.

A combination of an increasing power reserve margin (the amount of power supply in excess of demand) and low natural gas prices has led to a decrease in Alberta and U.K. power prices and the commensurate Spark Spreads. This affects approximately 437 MW of merchant power capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta-owned capacity of approximately 1,738 MW and 70 MW of merchant power capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of 262 MW.

The Corporation is unable to determine what future changes in commodity and energy markets could occur and how these changes could affect the Corporation.

PENSION PLANS

Declines in stock and bond markets, changes in actuarial assumptions and additional employee service have created funding deficits in the Corporation's defined benefit pension plans. The Corporation has not made material contributions since April 1, 1996, as a result of the defined benefit plans' surplus positions which existed in the past and were being used to fund the employer's contributions to the defined contribution component of the pension plans. Based on these changes material current service and deficit funding contributions will resume in 2010. The Corporation has applied to the AUC to recover the utility portion of the funding contributions from utility customers. For further information refer to Business Risks – Pension Plans section.

Forward-Looking Information

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

Non-GAAP Measures

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

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

Adjusted Earnings is defined as earnings attributable to Class A and Class B Shares after adjustment for items that are not in the normal course of business or day-to-day operations. These items are usually of a non-recurring or one-time nature. Management believes Adjusted Earnings allow for a more effective analysis of operating performance and trends. A reconciliation of Adjusted Earnings to earnings attributable to Class A and Class B Shares is presented in the Results of Operations – Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings section.

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2009, the Corporation's management evaluated the effectiveness of the Corporation's disclosure controls and procedures, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

Disclosure controls and procedures are controls and other procedures designed to provide reasonable assurance 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, inclusive of the CEO and the CFO, does not expect that the Corporation's disclosure controls and procedures will prevent or detect all errors 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 this evaluation, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Corporation's disclosure controls and procedures are effective in providing reasonable assurance that material information relating to the Corporation and its consolidated subsidiaries is made known to the CEO and the CFO by others within those entities on a timely basis.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2009, the Corporation's management evaluated the effectiveness of the Corporation's 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 GAAP.

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.

Based on this evaluation, the CEO and the CFO have concluded that, subject to the inherent limitations noted above, the Corporation's internal control over financial reporting is effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

There was no change in the Corporation's internal control over financial reporting that occurred during the period beginning on October 1, 2009, and ended on December 31, 2009, that has materially affected, or is reasonably likely to materially affect, the Corporation's internal control over financial reporting.

Annual Results of Operations

SELECTED INFORMATION

(\$ millions, except per share data, outstanding shares and % return on equity) ^{(1) (2) (7)}	For the Year Ended December 31		
	2009	2008	2007
Revenues	2,584.0	2,778.9	2,404.9
Earnings attributable to Class A and Class B shares	466.6	414.5	383.9
Adjusted Earnings ⁽³⁾	427.6	403.2	341.0
Total assets	9,083.6	7,860.0	7,299.7
Long term debt	3,102.3	2,844.3	2,603.2
Non-recourse long term debt	354.8	412.4	478.1
Equity preferred shares	785.0	625.0	625.0
Class A and Class B share owners' equity	3,046.1	2,748.5	2,517.1
Return on equity	16.1	15.7	15.9
Cash flow from operations	738.3	783.7	669.6
Funds Generated by Operations	793.4	796.5	688.6
Capital expenditures	946.1	1,010.9	700.8
Earnings per Class A and Class B share	3.71	3.30	3.06
Diluted earnings per Class A and Class B share	3.71	3.29	3.05
Adjusted Earnings per Class A and Class B share ⁽³⁾	3.40	3.21	2.72
Cash dividends declared per share:			
Series Second Preferred Shares:			
Series O ⁽⁴⁾	1.09	1.09	1.13
Series Q ⁽⁵⁾	-	-	0.68
Series R ⁽⁵⁾	-	-	0.61
Series S ⁽⁵⁾	-	-	0.77
Series T ⁽⁴⁾	1.09	1.09	1.09
Series U ⁽⁴⁾	1.09	1.09	1.09
Series V ⁽⁶⁾	1.18	1.18	1.28
Series W	1.45	1.45	1.45
Series X	1.50	1.50	1.50
Class A and Class B share	1.41	1.33	1.25
Equity per Class A and Class B share	24.20	21.90	20.09
Class A and Class B shares outstanding, year end (thousands)	125,860	125,510	125,295
Weighted average Class A and Class B shares outstanding (thousands):			
Basic	125,637	125,408	125,409
Diluted	125,774	125,784	125,934

Notes:

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

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

⁽³⁾ Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.

- (4) The dividend rate was reset to \$1.09 (from 5.05% to 4.35%) for the period between December 2, 2006, and December 2, 2011.
- (5) Series Second Preferred Shares Q, R and S were redeemed on May 18, 2007.
- (6) The dividend rate was reset to \$1.18 (from 5.25% to 4.70%) for the period between October 3, 2007, and October 3, 2012.
- (7) Certain numbers have been restated to reflect changes in accounting policies relating to rate regulated operations and goodwill and intangible assets (refer to Changes in Accounting Policies – Rate Regulated Operations and Goodwill and Intangible Assets sections).

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

Adjusted Earnings are referred to in various sections of this MD&A. The following table reconciles Adjusted Earnings, which are earnings attributable to Class A and Class B Shares after adjustments for items that are not in the normal course of business or day-to-day operations. These items are usually of a non-recurring or one-time nature. A description of each adjustment is provided in the Significant Non-Operating Financial Items section.

(\$ millions)	For the Year Ended December 31	
	2009	2008
Earnings attributable to Class A and Class B Shares	466.6	414.5
Mark-to-Market Adjustment ⁽¹⁾	7.4	2.0
H.R. Milner Income Tax Reassessment ⁽²⁾	(16.8)	-
Gain on transaction to combine ATCO Frontec, ATCO Structures and ATCO Noise Management ⁽³⁾	(29.6)	-
Other Post Employment Benefits ⁽⁴⁾	-	(7.0)
Federal Court of Appeal Decision- Mining Assets ⁽⁵⁾	-	(3.0)
2008 Tax Assessment ⁽⁶⁾	-	(3.3)
Adjusted Earnings	427.6	403.2

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

Consolidated and segmented financial results include the following significant non-operating financial items.

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

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

As all but the excess volume of natural gas is committed to the Corporation's power generation obligations, the Corporation does not recognize the entire fair values of these natural gas purchase contracts in its revenues. Consequently, the Corporation has recognized a provision for a power generation revenue contract and records adjustments to the power generation revenue contract liability concurrently with the mark-to-market adjustments for the natural gas purchase contracts derivative asset.

This power generation revenue contract liability is included in deferred credits in the consolidated balance sheet.

The mark-to-market adjustment for the derivative asset and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by \$2.0 million, net of income taxes, for the three months ended December 31, 2009 (2008 – decrease of \$1.1 million) and decreased earnings by \$7.4 million, net of income taxes, for the year ended December 31, 2009 (2008 – decrease of \$2.0 million). At December 31, 2009, the natural gas purchase contracts derivative asset was \$26.0 million (2008 – \$60.1 million) and the power generation revenue contract liability was \$20.4 million (2008 – \$44.6 million).

(2) H.R. Milner Income Tax Reassessment

In 2006, Canada Revenue Agency (CRA) issued an income tax reassessment for Alberta Power (2000)'s 2001 taxation year which treated the proceeds received from the sale of the H.R. Milner generating plant to the Balancing Pool as income rather than as a sale of an asset. The Corporation disagreed with CRA's position and appealed the reassessment to the Tax Court of Canada. Due to the uncertainty as to whether the reassessment would ultimately be resolved in the Corporation's favour, the Corporation made a \$28.8 million payment and reduced earnings by \$12.4 million in 2006.

On August 21, 2009, Alberta Power (2000) received a judgment from the Tax Court of Canada ordering CRA to reverse its 2006 reassessment of Alberta Power (2000)'s 2001 tax return. On September 30, 2009, the appeal period for the judgment elapsed without an appeal from CRA.

The impact of the judgment is a \$13.7 million recovery of income tax and related interest expense reassessed by CRA in 2006. In addition, Alberta Power (2000) will receive interest income of approximately \$3.1 million earned on such amounts paid to CRA. These adjustments have resulted in an \$16.8 million increase in earnings which was recorded in the third quarter of 2009. In total, Alberta Power (2000) is entitled to refunds of approximately \$28.0 million including interest and net of consequential adjustments to other taxation years arising from the judgment. Of this amount, the CRA has refunded \$20.8 million as of December 31, 2009, and approximately \$7.2 million remains outstanding from the Government of Alberta.

(3) Gain on Transaction to Combine ATCO Frontec, ATCO Structures and ATCO Noise Management

On July 1, 2009, the Corporation finalized the ATCO Structures & Logistics Transaction which resulted in an after tax gain of \$29.6 million (refer to Company Overview – Transaction To Combine ATCO Frontec, ATCO Structures and ATCO Noise Management section).

(4) Other Post Employment Benefits

In June 2008, the Corporation prospectively changed the method of apportioning the costs of OPEB plans to individual subsidiaries. Formerly, each subsidiary was apportioned a percentage of its payroll costs at a rate calculated for the plan as a whole. The revised method determines the accrued OPEB liabilities and costs on a company-by-company basis. Total consolidated accrued OPEB liabilities and costs did not change. Under the new method of apportioning, the 2008 OPEB liability for the regulated subsidiaries increased by \$10.4 million with a corresponding increase to non-current regulatory assets. Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for OPEB plans as paid. Consequently, there was no change to their 2008 earnings. The difference between the amounts accrued and paid is deferred in non-current regulatory assets.

The 2008 OPEB liability for the non-regulated subsidiaries decreased which resulted in an increase to earnings after income taxes of \$7.0 million, of which \$5.5 million was recorded in the second quarter of 2008, and \$1.5 million was recorded in the fourth quarter of 2008.

The 2008 earnings impact of the OPEB adjustment by segment was as follows:

(\$ millions)	Years Prior to 2008
Energy	3.9
Corporate & Other and Intersegment Eliminations	3.1
Total	7.0

(5) Federal Court of Appeal Decision – Mining Assets

On May 22, 2008, the Federal Court of Appeal issued a decision overturning previous CRA reassessments pertaining to the computation of resource allowances and corresponding capital cost allowances for mining assets related to the ATCO Group’s coal-fired power generation business. On July 8, 2008, the CRA advised that it would not seek leave to appeal to the Supreme Court of Canada in respect of this matter. This appeal and subsequent court decision applies to the 1997 to 1998 taxation years and allows ATCO Electric, and Alberta Power (2000) (as successor to ATCO Electric in the coal-fired generating plants), to claim additional resource allowance and capital cost allowance. ATCO Electric and Alberta Power (2000) have recorded a reduction in current income tax expense and a decrease in interest expense which resulted in increases to the Corporation’s earnings of \$3.0 million for the year ended December 31, 2008.

The earnings impact of this Federal Court of Appeal Tax Decision by segment was as follows:

(\$ millions)	Total
Utilities	2.2
Energy	0.8
Total	3.0

(6) 2008 Tax Assessment

In 2008 the Corporation received a favourable tax decision from the CRA to treat certain previously reported capital outlays as current expenditures for tax purposes in ATCO Electric and ATCO Pipelines. As a result the Corporation recognized a reduction in current income tax expense and an increase in interest income in respect of prior taxation years which resulted in an increase in earnings of \$3.3 million.

CONSOLIDATED REVENUES AND EARNINGS

Revenues in 2009 **decreased** by \$194.9 million (7%) compared to 2008. This decrease was primarily attributable to a \$211.3 million (17%) decrease in the Energy Segment and a \$102.4 million (23%) decrease in the Corporate & Other Segment, partially offset by a \$106.6 million (8%) increase in the Utilities Segment.

The **decrease** in **revenues** was primarily due to the impact of the ATCO Structures & Logistics Transaction, lower merchant performance in ATCO Power's Alberta generating plants due to lower pool prices in the Alberta electricity market and lower exchange rates on conversion of U.K. revenues into Canadian dollars in ATCO Power's U.K. operations. Also contributing to the decrease in revenues were lower NGL prices and volumes and lower sales of natural gas purchased for third parties in ATCO Midstream and the impact of applying new accounting standards in the Utilities Segment relating to the recognition of revenues for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). These decreases were partially offset by the impact of increased rate base in ATCO Electric and ATCO Gas (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – 2009 and 2010 General Tariff Application section and ATCO Gas – 2008 and 2009 General Rate Application section), increased storage revenues in ATCO Midstream due to the timing and demand for natural gas storage and higher AUC approved customer rates resulting from the ATCO Pipelines' negotiated settlement decision for 2008 and 2009 (ATCO Pipelines' Negotiated Settlement).

Earnings in 2009 were \$466.6 million, an **increase** of \$52.1 million (13%) over 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings were \$427.6 million, an **increase** of \$24.4 million (6%) over 2008. The primary reasons for increased Adjusted Earnings were the timing and demand for natural gas storage in ATCO Midstream, the impact of the ATCO Pipelines' Negotiated Settlement, lower operating and maintenance costs as compared to amounts that were included in ATCO Electric's and ATCO Gas' customer rates primarily due to cost efficiencies, the impact of increased rate base in ATCO Electric and ATCO Gas and the impact of the removal of the Carbon Facility from regulation and the suspension of the Carbon Rate Riders (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Gas – Carbon Natural Gas Storage Facility section). These increases were partially offset by lower merchant performance in ATCO Power's Alberta generating plants due to lower Spark Spreads in the Alberta electricity market and the 2008 recognition of insurance proceeds from the 2007/2008 Barking outage in ATCO Power's U.K. operations and lower margins and volumes for NGL extraction in ATCO Midstream.

Interest and other income in 2009 **decreased** by \$15.8 million to \$43.3 million compared to 2008, mainly due to lower rates of interest earned on cash balances and the mark-to-market adjustment in ATCO Power, partially offset by interest income recognized on the H.R. Milner Income Tax Reassessment in Alberta Power (2000) (recovery of \$7.5 million paid on the original 2006 income tax assessment and \$5.0 million of interest income pertaining to subsequent years) (refer to Annual Results of Operations – Significant Non-Operating Financial Items – H.R. Milner Income Tax Reassessment section).

CONSOLIDATED EXPENSES

(\$ millions)	For the Year Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Operating expenses:			
Natural gas supply	23.2	37.9	(39%)
Purchased power	54.1	54.1	0%
Operation and maintenance	965.5	1,123.5	(14%)
Selling and administrative	258.7	244.8	6%
Franchise fees	163.5	175.2	(7%)
	1,465.0	1,635.5	(10%)
Depreciation and amortization	329.7	387.2	(15%)
Interest	241.6	233.5	3%
Dividends on equity preferred shares	40.7	32.5	25%
Income taxes	125.4	134.8	(7%)

Operating expenses in 2009 **decreased** by \$170.5 million (10%) compared to 2008. Operation and maintenance expenses were lower primarily as a result of the impact of the ATCO Structures & Logistics Transaction, lower fuel costs in ATCO Power's Alberta and U.K. generating facilities and lower natural gas prices and volumes in NGL extraction operations in ATCO Midstream. These decreases were partially offset by higher operating costs due to the impact of applying new accounting standards in the Utilities Segment relating to the treatment of future removal and site restoration costs for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). Selling and administrative expenses increased in the Utilities Segment primarily as a result of higher employment costs due to growth and higher rate hearing costs relating to regulatory applications, partially offset by lower selling and administrative costs due to the impact of the ATCO Structures & Logistics Transaction. Decreased franchise fees, recovered on a flow through basis, were paid in ATCO Gas.

In 2009, **depreciation and amortization expenses decreased** by \$57.5 million (15%) compared to 2008, primarily due to the impact of applying new accounting standards in the Utilities Segment relating to the treatment of future removal and site restoration costs for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). These decreases were partially offset by capital additions in 2008 and 2009 in the Utilities Segment.

Interest expense in 2009 **increased** by \$8.1 million (3%) over 2008, primarily due to increased amounts of debt outstanding (net of redemptions) resulting from new financings issued in 2008 and 2009 to fund capital expenditures in the Utilities Segment, partially offset by the repayment of ATCO Power's non-recourse financings in 2008 and 2009.

Dividends on equity preferred shares in 2009 **increased** by \$8.2 million (25%) over 2008 as a result of the issue by CU Inc. of \$160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2 on March 27, 2009.

In 2009, **income taxes decreased** by \$9.4 million (7%) compared to the same period in 2008, primarily due to a \$7.8 million tax adjustment as a result of the H.R. Milner Income Tax Reassessment in Alberta Power (2000) and a non-taxable gain as a result of the impact of the ATCO Structures & Logistics Transaction, partially offset by higher earnings before taxes and a \$6.1 million income tax adjustment in ATCO Gas as a result of the removal of the Carbon Facility from regulation.

SEGMENTED INFORMATION

(\$ millions)	For the Year Ended December 31				Total
	Utilities	Energy	Corporate & Other	Intersegment Eliminations	
2009					
Revenues	1,367.5	1,031.4	344.9	(159.8)	2,584.0
Earnings attributable to Class A and Class B Shares	195.4	209.5	60.8	0.9	466.6
Mark-to-Market Adjustment ⁽¹⁾	-	7.4	-	-	7.4
H.R. Milner Income Tax Reassessment ⁽²⁾	-	(16.8)	-	-	(16.8)
Gain on transaction to combine ATCO Frontec, ATCO Structures and ATCO Noise Management ⁽³⁾	-	-	(29.6)	-	(29.6)
Adjusted Earnings	195.4	200.1	31.2	0.9	427.6
Capital expenditures	776.1	151.5	18.5	-	946.1
Operating expenses	772.2	591.5	262.4	(161.1)	1,465.0
2008					
Revenues	1,260.9	1,242.7	447.3	(172.0)	2,778.9
Earnings attributable to Class A and Class B Shares	148.6	223.0	44.0	(1.1)	414.5
Mark-to-Market Adjustment ⁽¹⁾	-	2.0	-	-	2.0
Other Post Employment Benefits ⁽⁴⁾	-	(3.9)	(3.1)	-	(7.0)
Federal Court of Appeal Decision- Mining Assets ⁽⁵⁾	(2.2)	(0.8)	-	-	(3.0)
2008 Tax Assessment ⁽⁶⁾	(3.3)	-	-	-	(3.3)
Adjusted Earnings	143.1	220.3	40.9	(1.1)	403.2
Capital expenditures	852.6	109.7	48.6	-	1,010.9
Operating expenses	718.7	745.8	341.4	(170.4)	1,635.5

Notes:

⁽¹⁾ ⁽²⁾ ⁽³⁾ ⁽⁴⁾ ⁽⁵⁾ ⁽⁶⁾ Refer to Significant Non-Operating Financial Items section for a description of the adjustments.

Utilities

ATCO Electric, ATCO Gas and ATCO Pipelines are regulated primarily by the AUC, which administers acts and regulations covering such matters as rates, financing, accounting and service area. These utilities are subject to a cost of service regulatory mechanism under which the AUC establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization and income taxes, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment, or rate base. Rate base for each utility is the aggregate of the AUC approved investment in property, plant and equipment and intangible assets, less accumulated depreciation and amortization, reserves for future removal and site restoration, and unamortized contributions by utility customers for extensions to plant, plus an allowance for working capital. The utilities earn a return on rate base intended to meet the cost of the debt and preferred share components of rate base and to provide share owners with a fair return on the common equity component of rate base. The determination of a fair return to the common shareholders involves an assessment by the regulator of many factors, including returns on alternative investment opportunities of comparable risk and the level of return which will enable a utility to attract the necessary capital to fund its operations and to maintain financial integrity.

Utilities **revenues** in 2009 were \$1,367.5 million, an **increase** of \$106.6 million (8%) over 2008, primarily attributable to the impact of increased rate base in ATCO Electric and ATCO Gas (refer to Regulatory Developments – ATCO Electric – 2009 and 2010 General Tariff Application section and ATCO Gas – 2008 and 2009 General Rate Application section) and higher AUC approved customer rates resulting from ATCO Pipelines’ Negotiated Settlement. Also contributing to the increase in revenues were the impact of removal of the Carbon Facility from regulation and the suspension of the Carbon Rate Riders (refer to Regulatory Developments – ATCO Gas – Carbon Natural Gas Storage Facility section) in ATCO Gas and the impact of the 2009 generic cost of capital decision in ATCO Electric and ATCO Gas (2009 Generic Cost of Capital Decision). These increases were partially offset by the impact of applying new accounting standards in ATCO Electric, ATCO Gas and ATCO Pipelines relating to the recognition of revenues for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section) and lower franchise fees collected on behalf of municipalities in ATCO Gas.

Earnings for 2009 were \$195.4 million, an **increase** of \$46.8 million (31%) over 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2009, **Adjusted Earnings** were \$195.4 million, an **increase** of \$52.3 million (37%) over 2008. The primary reasons for higher Adjusted Earnings were the impact of the ATCO Pipelines’ Negotiated Settlement, lower operating and maintenance costs as compared to amounts that were included in ATCO Electric’s and ATCO Gas’ customer rates primarily due to cost efficiencies, the impact of increased rate base in ATCO Electric and ATCO Gas and the impact of the removal of the Carbon Facility from regulation and the suspension of the Carbon Rate Riders. These increases in Adjusted Earnings were partially offset by higher financing costs in ATCO Electric compared to amounts included in customer rates and lower sales in ATCO Gas due to lower customer growth compared to amounts included in customer rates.

Regulatory Developments

Generic Cost of Capital

On November 12, 2009, the AUC issued its decision on the 2009 Generic Cost of Capital proceeding. In this decision, the AUC set the 2009 and 2010 generic return on equity (ROE) at 9.0% for all Alberta utilities which it regulates. This is an increase over the 8.61% ROE that the adjustment formula formerly in place would have provided for 2009. The AUC has maintained the concept of a single generic ROE for all utilities, with differences in utility or sector specific risk to be recognized through the adjustments of individual common equity ratios. The AUC determined the common equity ratio to be 36% for ATCO Electric’s transmission operations, 39% for both ATCO Electric’s distribution operations and ATCO Gas’ operations and 45% for ATCO Pipelines’ operations. As part of the same decision, the AUC also set the 2011 generic return on equity at 9.0% on an interim basis subject to change following a subsequent generic proceeding. The financial impact of this decision was an increase to ATCO Electric’s earnings of \$4.2 million and ATCO Gas’ earnings of \$2.5 million, of which \$0.4 million relates to 2008. The changes did not apply to ATCO Pipelines for 2009 since capital structure and rate of return were included in ATCO Pipelines’ Negotiated Settlement.

While ATCO Gas’ ROE for 2008 was not impacted by the decision issued on November 12, 2009, a separate module within the generic proceeding addressed ATCO Gas’ 2008 capital structure, as inclusion of this issue was removed from its 2008/2009 general rate application. The November 12, 2009 decision approved an equity ratio of 39% commencing in the year 2008 for ATCO Gas. The financial impact is identified in the 2008 amount noted above.

Pension Hearing

In July 2009, the ATCO Utilities submitted an application to the AUC requesting the creation of deferral accounts to record company contributions to the Canadian Utilities pension plan which are expected to be incurred in 2010. The recovery of amounts paid and recorded in the deferral accounts would be through an increase in customer rates. A hearing was held in January 2010 and with normal process a decision from the AUC is expected in the second quarter of 2010.

Benchmarking

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

The benchmarking report, dealing with the period of 2003-2007, was received on January 23, 2008. In February 2008, the benchmarking report along with an application to adjust the Placeholder rates was filed with the AUC. A hearing was held in December 2009 and a decision is expected in the first quarter of 2010.

All parties continue to support the calculation of fair market value provided in the benchmarking report. The issue in the regulatory proceeding is whether fair market value or some other basis should be used to finalize the Placeholders. If fair market value is used as the basis to finalize the Placeholders for the period 2003-2007 then there will not be a material impact on consolidated earnings.

For the 2008 and 2009 period, a separate regulatory process will occur to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The 2008-2009 proceeding will commence after the completion of the 2003-2007 process.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process after the completion of the 2008-2009 process.

In addition to the rates, this process includes the review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the ATCO Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. On December 11, 2009, the AUC issued a decision approving the implementation of the new Master Service Agreements (excluding the rates therein) with ATCO I-Tek for information technology and customer care and billing services effective January 1, 2010 for an interim period, the term of which will be determined in the upcoming regulatory process.

Income Tax Module

On November 12, 2009, the AUC issued its Income Tax Module decision in which it addressed the 2008-2009 income tax Placeholder amounts for ATCO Gas and 2009-2010 Placeholders for ATCO Electric. The AUC approved the Placeholder amounts as filed and established an income tax deferral account for ATCO Electric and ATCO Gas, resulting in no impact to earnings for ATCO Electric and a \$2.5 million reduction in earnings for ATCO Gas.

Utility Asset Disposition Rate Review Proceeding

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

The AUC has indicated that the Stores Block Decision may have various implications with respect to regulation of Alberta utility companies (including the potential impact of the Carbon Natural Gas Storage Facility decision discussed below). The AUC has stated that it would like to develop a comprehensive understanding of these potential implications through this proceeding and then apply this understanding in a consistent manner in future decisions. At the conclusion of this proceeding, the AUC will issue a decision reflecting its conclusions with respect to the interpretation and application of the guidance provided by the courts and the resulting implications to be used in future proceedings. On November 28, 2008, the AUC suspended the utility asset disposition rate review proceeding until further notice to allow for various related matters currently before the courts to be addressed.

ATCO Electric

2009 and 2010 General Tariff Application

In July 2008, ATCO Electric filed a general tariff application with the AUC for 2009 and 2010 requesting, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. ATCO Electric filed an application requesting interim refundable rates pending the AUC's decision on the application. In December 2008, ATCO Electric received a decision from the AUC approving interim refundable rate increases amounting to 50% of the requested increase for transmission operations and 25% of the requested increase for distribution operations. On March 11, 2009, ATCO Electric filed an application requesting an increase to its approved interim refundable rates for its distribution operations. A decision from the AUC was received on April 22, 2009, which resulted in an increase to the interim refundable rates to 67% of the requested rate increase.

On July 2, 2009, the AUC issued a decision on ATCO Electric's 2009 and 2010 general tariff application. The effect of the decision increased ATCO Electric's 2009 annual earnings approximately \$10 million compared to 2008. This increase is primarily the result of an increase in rate base of \$290 million compared to 2008. In the decision, the AUC used Placeholders for 2009 and 2010 information technology and customer care and billing rates and pension costs. These Placeholders will be determined by the AUC in subsequent proceedings. The Placeholders in the decision for common equity ratios, preferred share capitalization ratios and ROE were determined as a result of the Generic Cost of Capital Decision discussed above. The Placeholders in the decision for the income tax amounts were determined as a result of the Income Tax Module Decision discussed above.

Transmission Infrastructure Projects

Northwest Alberta Transmission Projects

In August 2006, the AUC approved the AESO application for increased transmission infrastructure in northwest Alberta. The AESO has approval to assign to the transmission facility owner, ATCO Electric, work consisting of four distinct transmission line projects that is expected to result in 725 kilometres of new transmission lines to be constructed by 2012.

To date, all four transmission line projects have been assigned to ATCO Electric by the AESO with final approval having been received from the AUC for three of these projects relating to the construction of 622 kilometres of transmission line with an estimated cost of \$425.0 million and anticipated completion by March 31, 2011. ATCO Electric has completed construction of one 226 kilometre major transmission line and is currently constructing two other transmission lines in northwest Alberta totaling approximately 396 kilometres. In addition to the three transmission line projects, seven additional infrastructure projects in the northwest with an estimated cost of \$58.0 million are anticipated to be complete by the end of 2010.

The total cost estimate and timing of the remaining transmission line project to be approved by the AUC in northwest Alberta is dependent on changing economic conditions as well as receiving all regulatory approvals on a timely basis. As a result of these variables, ATCO Electric is unable at this time to determine the completion dates or the cost of the entire project.

AESO Long-Term Transmission System Plan

In June 2009, the AESO announced its long-term transmission system plan which is in addition to the increased transmission infrastructure in northwest Alberta. This plan identifies \$8.1 billion of critical transmission infrastructure projects that are needed between 2010 and 2017 to meet current and future electricity needs in Alberta and a further \$6.4 billion in projects that are at a less advanced stage of planning. The Alberta government passed amendments to the Alberta Utilities Commission Act, the Electric Utilities Act, and the Hydro and Electric Energy Act to expedite the determination of these critical transmission infrastructure projects. The amendments to the Electric Utilities Act allow the government to direct assign projects, utilize service territory assignments or put major projects out for bid.

On August 25, 2009, ATCO Electric was authorized by the Alberta Minister of Energy to prepare a facilities application to build and operate a new high-voltage transmission line along a corridor on the east side of the province between Edmonton and Calgary. On December 9, 2009, the Alberta Minister of Energy amended its August 2009 authorization to ATCO Electric to allow for a staging of the requirements over a number of years. Following approval of the facilities application by the AUC, ATCO Electric will construct and operate the new line. The AESO, in its long-term transmission system plan, estimates the project will cost \$1.65 billion, in 2008 dollars, and it is anticipated that the majority of these costs will be incurred after 2011.

In addition to the increased transmission infrastructure in northwestern Alberta, ATCO Electric anticipates that 500 - 1,000 kilometres of transmission line projects will be required in its service area over the next five years. The increase in kilometres is mainly as a result of projects identified in the AESO's long-term transmission plan.

ATCO Gas

2008 and 2009 General Rate Application

On November 13, 2008, ATCO Gas received a decision on its general rate application for 2008 and 2009. The decision established the amount of revenue requirement ATCO Gas can recover through distribution rates for natural gas distribution service to its customers for 2008 and 2009. The effect of the decision on ATCO Gas' 2009 annual earnings was an increase of approximately \$3 million over 2008 resulting primarily from an increase in rate base. In the decision, the AUC used Placeholders for 2009 information and technology and customer care and billing costs. These Placeholders will be determined by the AUC in subsequent proceedings. The Placeholders in the decision for common equity ratios, preferred share capitalization ratios and ROE were determined as a result of the Generic Cost of Capital Decision

discussed above. The Placeholders for income tax amounts were determined as a result of the Income Tax Module Decision discussed above.

Deferred Gas Account

ATCO Gas filed an application with the AUC to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in the Corporation's pipelines) that have impacted ATCO Gas' deferred gas account. In April 2005, the AUC issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in ATCO Gas recovering \$9.2 million in natural gas supply costs from customers. This decision has been the subject of a number of legal appeal proceedings initiated by the City of Calgary. The City of Calgary's current appeal with respect to this decision was heard by the Alberta Court of Appeal on January 13, 2010. A decision is expected in the first half of 2010.

Carbon Natural Gas Storage Facility

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta (Carbon Facility). Since April 1, 2005, ATCO Gas has leased the entire storage capacity of the Carbon Facility to ATCO Midstream. Due to the deregulation of the natural gas market, ATCO Gas notified the AUC that the Carbon Facility was no longer required for the provision of utility service as of April 1, 2005. As a result of numerous regulatory and legal proceedings, ATCO Gas has received approval from the AUC to remove the Carbon Facility from regulation. On December 16, 2009 a Review and Variance decision issued by the AUC confirmed the effective date of removing the Carbon Facility from regulation to be April 1, 2005.

On an annual basis, the amount refunded to customers through the Carbon Rate Riders was approximately \$25.0 million. In addition, on an annual basis, the revenue recovered from customers as a result of costs for the Carbon Facility was approximately \$13.5 million. ATCO Gas, effective July 1, 2008, received approval from the AUC to suspend on an interim basis customer rate riders (Carbon Rate Riders) that were approved in the past to distribute net revenues related to the Carbon Facility to customers. Therefore, the annual pre-tax financial impact to ATCO Gas of the suspension of Carbon Rate Riders net of the costs for the Carbon Facility is approximately \$11.5 million per year. The annual increase to ATCO Gas' earnings is approximately \$8.3 million. These amounts can vary on a year to year basis as a result of changes in the price of natural gas.

Removal from Regulation

In the third quarter of 2009, ATCO Gas removed the Carbon Facility from regulation for accounting purposes. This resulted in ATCO Gas derecognizing all previously recorded regulatory assets and liabilities relating to the Carbon Facility as these amounts were no longer recoverable from or payable to ATCO Gas' customers. The one-time impact of this discontinuation of regulatory accounting for the Carbon Facility was to increase ATCO Gas' earnings by \$1.9 million in the third quarter of 2009.

Suspension of Carbon Rate Riders

Further to its decision suspending Carbon Rate Riders on an interim basis effective July 1, 2008, the AUC on July 28, 2009 issued a decision approving a refund to customers related to the costs of the Carbon facility that were included in ATCO Gas' rates from January through June 2008. In the third quarter of 2009, ATCO Gas recorded the impact of the suspension of the Carbon Rate Riders for the period January 1, 2008 to June 30, 2008 based on a decision received on July 28, 2009. ATCO Gas recognized increased revenues of \$13.8 million for the impact of the Carbon Rate Rider revenue for the period January 1, 2008

to June 30, 2008 which was previously refunded to customers and decreased revenues of \$7.6 million as a result of excluding any costs for the Carbon Facility in its 2008-2009 general rate application. The net impact was an increase to ATCO Gas' revenues and earnings of \$6.2 million and \$4.5 million, respectively, in the third quarter of 2009.

For the remaining period of April 1, 2005 to December 31, 2007, ATCO Gas is seeking to recover from customers additional amounts that would result in an estimated increase to its earnings of \$20.5 million, excluding interest. The finalization of these amounts that ATCO Gas is seeking to recover will be determined in a subsequent process scheduled to occur over the first and second quarters of 2010. As a result, these additional amounts have not yet been recognized by ATCO Gas. The City of Calgary and the Utilities Consumer Advocate have filed a joint Leave to Appeal application with the Alberta Court of Appeal regarding the December 16, 2009 decision. As a result of the Leave to Appeal, the effective removal date of the Carbon assets of April 1, 2005 could be impacted, which could affect the amount ATCO Gas is seeking to recover from customers. A hearing for the Leave to Appeal application has been tentatively scheduled for April 28, 2010.

ATCO Pipelines

2008 and 2009 General Rate Application

In November 2008, ATCO Pipelines filed an application requesting the AUC approve a negotiated settlement with its customers of ATCO Pipelines' 2008 and 2009 revenue requirements. On March 18, 2009, the AUC issued a decision approving the negotiated settlement, including, among other things, a rate of return on common equity of 8.75% and a common equity ratio of 43% for each of 2008 and 2009. As a result of the decision, ATCO Pipelines recognized additional earnings over existing interim rates of \$4.5 million in the first quarter of 2009, of which \$3.7 million related to 2008.

Alberta System Integration

On September 8, 2008, ATCO Pipelines and NOVA Gas Transmission Ltd. (NOVA) announced a proposed agreement to provide natural gas transmission service to their customers. The proposal will allow ATCO Pipelines and NOVA to utilize their physical assets under a single rates and services structure with a single commercial interface for Alberta customers. Each company would separately manage assets within distinct operating territories within Alberta. This proposal, if approved by the AUC, is expected to end duplicate tolling and operational activities and result in more efficient regulatory processes.

On June 26, 2009, ATCO Pipelines filed an application with the AUC for the integration of ATCO Pipelines' and NOVA's gas transmission systems in Alberta (Integration Application). The Integration Application requests the AUC to approve that (i) integration is in the public interest, (ii) ATCO Pipelines approved revenue requirements be charged to NOVA, (iii) ATCO Pipelines customers be transitioned to NOVA, with NOVA as the customer commercial point of contact, and (iv) ATCO Pipelines and NOVA swap assets in order to establish operating areas. A negotiated settlement on ATCO Pipelines' 2010, 2011 and 2012 revenue requirements is a condition precedent of the Integration Application. A settlement on ATCO Pipelines 2010, 2011 and 2012 revenue requirements was successfully negotiated with interested parties on October 28, 2009. On November 12, 2009, ATCO Pipelines filed a request with the AUC to approve its 2010, 2011 and 2012 Revenue Requirement Settlement Application as part of its Integration Application. ATCO Pipelines expects to receive an AUC decision on the Integration Application in the first half of 2010.

Other Matters

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

Energy

Energy **revenues** in 2009 decreased by \$211.3 million (17%) to \$1,031.4 million compared to 2008 primarily due to lower merchant performance in ATCO Power's Alberta generating plants due to lower prices in the Alberta electricity market, lower exchange rates on conversion of U.K. revenues into Canadian dollars and lower natural gas fuel purchases recovered on a "no-margin" basis in ATCO Power's U.K. operations. Also contributing to the decrease in revenues were lower NGL prices and volumes and lower sales of natural gas purchased for third parties in ATCO Midstream. These decreases were partially offset by increased storage revenues in ATCO Midstream due to the timing and demand for natural gas storage.

Energy **earnings** for 2009 **decreased** by \$13.5 million (6%) to \$209.5 million compared to 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings were \$200.1 million, a **decrease** of \$20.2 million (9%) compared to 2008, primarily due to lower merchant performance in ATCO Power's Alberta generating plants due to lower Spark Spreads in the Alberta electricity market, the 2008 recognition of insurance proceeds from the 2007/2008 Barking outage and lower exchange rates on the conversion of U.K. earnings to Canadian dollars in ATCO Power's U.K. operations. Also contributing to the decreased earnings were lower margins and volumes for NGL extraction in ATCO Midstream. These decreases in Adjusted Earnings were partially offset by the timing and demand for natural gas storage resulting in higher storage fees in ATCO Midstream.

Power Generation

Availability of the generating plants by geographic region is set forth below:

	For the Year Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
ATCO Power ⁽¹⁾ :			
Canada	96.3%	94.9%	1.4%
U.K. ⁽²⁾	96.3%	87.8%	8.5%
Australia	96.9%	98.7%	(1.8%)
Alberta Power (2000) ⁽¹⁾ :			
Canada	91.9%	91.8%	0.1%

Notes:

⁽¹⁾ *Generating plant availability will fluctuate due to the timing and duration of outages.*

⁽²⁾ *The higher availability for the year ended December 31, 2009, reflects the unplanned outage at the Barking generating plant which commenced on October 25, 2007. The plant returned to service in the first quarter of 2008.*

Unplanned Outage at Barking Generating Plant

On October 25, 2007, ATCO Power's 1,000 MW Barking generating plant in the U.K. experienced an unplanned outage due to failure in a steam turbine generator. On March 6, 2008, ATCO Power announced that the plant had returned to service. This outage reduced the plant capacity to approximately 400 MWs during this period. The financial impact of the failure, prior to the recognition of insurance proceeds, was a decrease to ATCO Power's earnings of \$13.4 million (2007 earnings were decreased by \$8.6 million and 2008 first quarter earnings were reduced by \$4.8 million). Additionally, during the first quarter of 2008, \$8.1 million of business interruption and property damage insurance proceeds were recorded (\$3.3 million related to 2007 and \$4.8 million related to the first quarter of 2008).

The financial impact of the failure, including the recognition of the insurance proceeds, was a decrease to the Corporation's consolidated earnings of \$8.6 million in 2007 and an increase to earnings of \$3.3 million for the year ended December 31, 2008, which was recorded in the first quarter of 2008. The final insurance settlement will be determined once repairs associated with the outage are complete, which is expected to be in the second quarter of 2010.

TXU Europe Settlement

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

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

The Corporation's share of this settlement is being recognized in earnings in equal monthly amounts over the remaining term of the TXU Europe contract to September 30, 2010. Based on the foreign currency exchange rate in effect at December 31, 2009, earnings after income taxes of approximately \$6.4 million have yet to be recognized. These earnings will be dependent upon foreign currency exchange rates in effect at the time that the earnings are recognized.

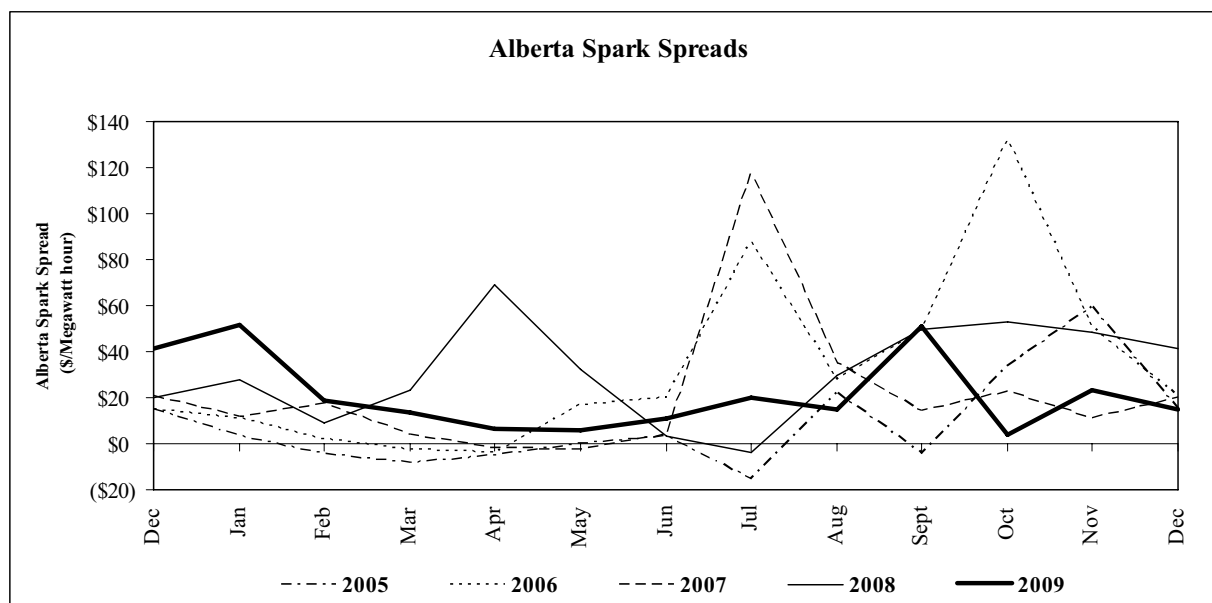
Other Power Generation Developments

On January 30, 2008, the 150 MW Unit 4 at Alberta Power (2000)'s Battle River generating plant experienced an unplanned outage due to a failure in the unit's generator. The unit returned to service on March 27, 2008. Alberta Power (2000) claimed relief under the force majeure provisions of its PPA. These provisions provide protection for the operator against mechanical failures which last more than forty-two days, except for circumstances where it is found that the operator failed to follow good operating practices. On July 11, 2008, the Balancing Pool notified Alberta Power (2000) that it disagreed with Alberta Power (2000)'s claim for relief under the force majeure provisions of the PPA. Unless settlement on the claim can be reached with the PPA counterparty, it is anticipated that this claim will proceed to arbitration. The cash impact resulting from this outage was approximately \$11.8 million, however, due to Alberta Power (2000)'s availability incentive pool deferral account there was no material earnings impact.

The majority of ATCO Power's electricity sales to the Alberta Power Pool are from natural gas-fired generating plants and, as a result, earnings are affected by natural gas prices and Alberta Power Pool prices. Alberta Power Pool electricity prices averaged \$47.81 per MWh in 2009, compared to average prices of \$89.95 per MWh in 2008. Natural gas prices averaged \$3.76 per GJ, compared to average prices of \$7.73 per GJ in 2008. These electricity and natural gas prices resulted in an average Spark Spread of \$19.58 per MWh in 2009, compared to \$32.00 per MWh in 2008.

Changes in Spark Spread currently affect the results of approximately 437 MW of plant capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta-owned capacity of approximately 1,738 MW and approximately 70 MW of plant capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of approximately 262 MW and a worldwide owned capacity by ATCO Power and Alberta Power (2000) of approximately 2,503 MW.

A combination of an increasing power reserve margin (the amount of power supply in excess of demand) and low natural gas prices has led to a decrease in Alberta power prices and the commensurate Spark Spreads. The following chart demonstrates the volatility of Alberta Spark Spreads experienced by ATCO Power for the period of December 2004 to December 2009.



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

Alberta Power (2000)

The generating plants of Alberta Power (2000) were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are included in regulated operations primarily because the PPAs are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPAs expiring prior to 2019, Alberta Power (2000) has one year after the expiry of a PPA to determine whether to decommission the generating plant in order to fully recover plant decommissioning costs or to continue to

operate the plant and be responsible for decommissioning costs. For PPAs expiring after 2018, decommissioning costs are the responsibility of the plant owner. Each PPA is to remain in effect until the earlier of the last day of the estimated life of the related generating plant or December 31, 2020.

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a rate of return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPAs were based. The return on common equity rate used in its PPA tariff calculations for Alberta Power (2000) was 8.64% in 2009 and 8.88% for 2008. The rate of return on common equity for 2010 is 8.44%.

Under the terms of the PPAs, Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets, and penalties are payable by Alberta Power (2000) when the availability targets are not achieved. These amounts are amortized based on estimates of future generating unit availability and future electricity prices over the term of the PPAs.

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

During 2009, the **deferred availability incentive** account increased by \$5.9 million to \$67.1 million, mainly due to high availability offset by amortization. The amortization of deferred availability incentives, recorded in revenues, increased by \$3.7 million to \$16.3 million, primarily as a result of changes in assumptions related to the terms of the PPAs. Previous assumptions were based on a single term for the PPAs at the Battle River generating plant. These assumptions have been revised to coincide with the term of the Battle River individual unit PPAs. The change associated with the updated assumptions increased 2009 revenues by approximately \$3.8 million.

ATCO Midstream

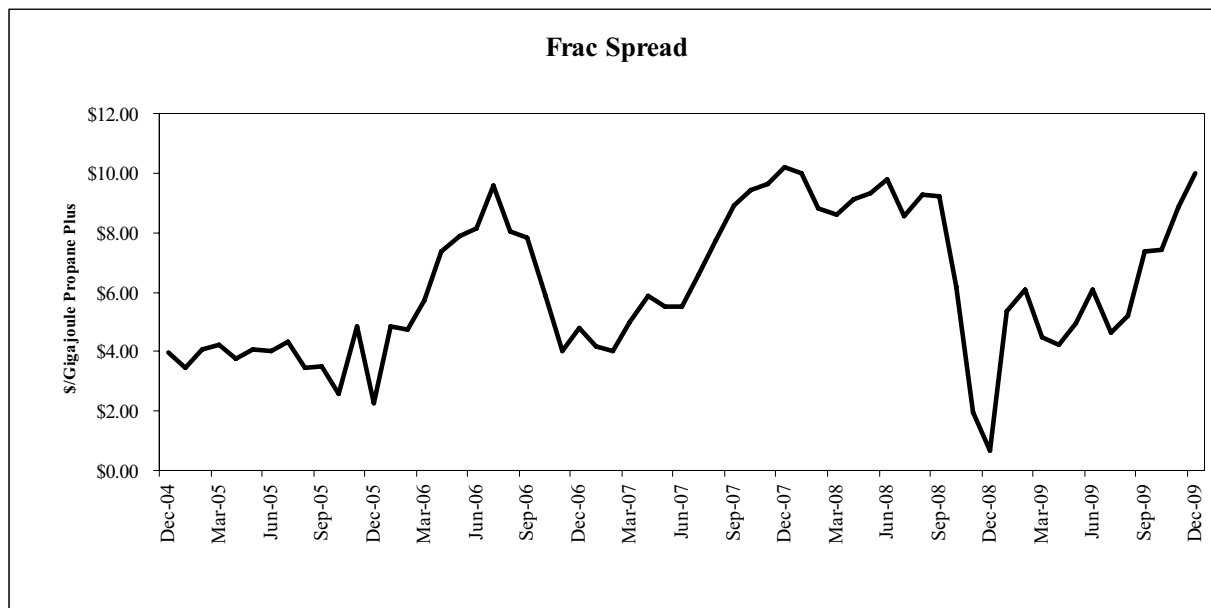
ATCO Midstream engages in non-regulated natural gas gathering, processing, storage and natural gas liquids extraction services and sales.

NGL Extraction Operations

A portion of ATCO Midstream's revenues is derived from the extraction of NGL from natural gas and the marketing of NGL products under supply or marketing contracts. ATCO Midstream owns a net working interest of 411 million cubic feet per day of processing capacity in its NGL extraction plants.

ATCO Midstream's NGL extraction operations involve the extraction of NGL from natural gas and the replacement (on a heat content equivalent basis) of the NGL extracted with shrinkage gas. For Propane Plus, the difference between the price of natural gas and the value of the liquids extracted is commonly referred to as the Frac Spread. Frac Spreads vary with fluctuations in the price of natural gas and the

prices of the applicable liquids extracted. Frac Spreads can be volatile, as shown in the following graph, which illustrates monthly Frac Spreads during the period of December 2004 to December 2009.



Note:

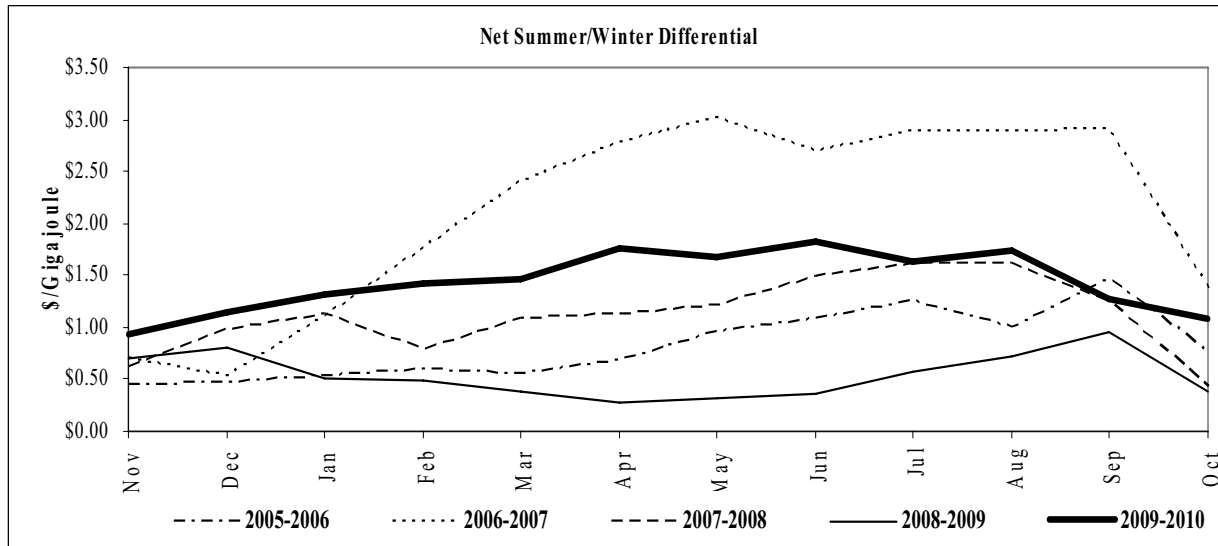
⁽¹⁾ The above chart represents measurements of industry Frac Spreads in Alberta, as reported by an independent consultant.

Fluctuations in Frac Spreads affect ATCO Midstream’s earnings and cash flow from operations. At current values, a \$1.00 change in the average annual Frac Spread impacts ATCO Midstream’s annual earnings by approximately \$6.0 million.

Storage Operations

The majority of ATCO Midstream’s natural gas storage revenues come from seasonal differences (summer/winter) in the price of natural gas (price differentials).

Summer/winter natural gas price differentials can be volatile, as shown in the following graph, which illustrates a range of seasonal differentials experienced during the storage periods from the 2005-2006 storage year to the 2009-2010 storage year. Price differentials at any point in time may not always be indicative of the storage revenue and earnings for the same period due to the types of contracts and the timing of the revenue recognition associated with these contracts.



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

Corporate & Other

Earnings in 2009 were \$60.8 million, an **increase** of \$16.8 million (38%) over 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

In 2009, **Adjusted Earnings** were \$31.2 million, a **decrease** of \$9.7 million (24%) compared to 2008. The primary reason for the decrease was lower short term interest rates on cash investments.

ATCO I-Tek

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

ATCO I-Tek provides billing services, payment processing, credit, collection and call centre services to its clients. ATCO I-Tek currently provides such services to Direct Energy for its regulated retail and competitive energy supply businesses in Alberta. In addition, ATCO I-Tek also supplies distribution-related billing and customer care services to ATCO Gas and ATCO Electric. In 2009, ATCO I-Tek entered into a strategic relationship with Wipro, a large multinational service provider to provide joint delivery of some customer care services and to pursue new opportunities in the utility business process outsourcing market. A portion of ATCO I-Tek's call centre services is now being handled by Wipro out of the Philippines as part of this new strategic relationship.

Direct Energy entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek to provide billing and call centre services to ensure continued quality customer service. Direct Energy has the ability to terminate this contract after the fifth anniversary, which occurred on May 4, 2009, 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 approximately \$500 million over the term of the contract.

Liquidity and Capital Resources

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

SUMMARY OF CASH FLOW

(\$ millions)	For the Year Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Cash position, beginning of period	726.6	747.2	(3%)
Cash provided by (used in)			
Operating activities:			
Funds generated by operations	793.4	796.5	0%
Changes in non-cash working capital	(55.1)	(12.8)	(330%)
Cash flow from operations	738.3	783.7	(6%)
Investing activities	(852.1)	(806.1)	6%
Financing activities	197.0	13.1	1,404%
Foreign currency impact on cash balances	(4.9)	(11.3)	57%
Decrease in cash on ATCO Structures & Logistics transaction	(8.9)	-	0%
Cash position, end of period	796.0	726.6	10%

OPERATING ACTIVITIES

Funds generated by operations were \$793.4 million in 2009, a **decrease** of \$3.1 million (0%) compared to 2008. This decrease was primarily due to lower deferred availability incentives. In 2009, **cash flow from operations** was \$738.3 million, a **decrease** of \$45.4 million (6%) compared to 2008. This decrease was primarily due to changes in non-cash working capital.

INVESTING ACTIVITIES

In 2009, **cash used in investing activities increased** by 6% over 2008, primarily due to changes in non-cash working capital and lower contributions by utility customers for extensions to plant partially offset by lower capital expenditures. **Capital expenditures** in 2009 **decreased** by \$64.8 million compared to 2008. This decrease was primarily due to decreased investment in natural gas distribution projects in ATCO Gas and the impact of the ATCO Structures & Logistics Transaction. These decreases in capital expenditures were partially offset by increased investment in non-regulated electric transmission projects by ATCO Energy Solutions and the construction of the Karratha generating plant by ATCO Power.

Capital Expenditures

For the Year Ended
December 31

(\$ millions)	For the Year Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Utilities	776.1	852.6	(9%)
Energy	151.5	109.7	38%
Corporate & Other	18.5	48.6	(62%)
	946.1	1,010.9	(6%)

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately \$1.4 billion in 2010, an **increase** of \$0.5 billion over 2009. The majority of these expenditures relate to the Utilities Segment. For the 2010 to 2012 period, capital expenditures in the Utilities Segment are expected to be approximately \$3.5 billion to \$4.5 billion (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – Transmission Infrastructure Projects section).

The planned capital expenditures for the Utilities Segment are based on the following assumptions:

- the projects identified by the AESO will proceed as currently scheduled;
- the remaining planned capital expenditures in the Utilities Segment are required to maintain capacity and meet planned growth in the Corporation's service areas. These expenditures are consistent with the anticipated growth in the Alberta economy and in the Corporation's service areas; and
- the regulatory system in Alberta will remain substantially unchanged.

In the opinion of the Corporation, these assumptions are reasonable, but no assurance can be given that these assumptions will prove to be correct.

ATCO Electric, ATCO Gas and ATCO Pipelines are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance of capital expenditures incurred if the AUC determines that such costs were not prudently incurred. This risk is mitigated by the inclusion of capital expenditures in general rate applications approved by the AUC. Furthermore, all major electric transmission projects assigned by the AESO to ATCO Electric are required to be approved by the AUC prior to commencing construction.

Tightness in labour and materials markets in Alberta in recent years has resulted in substantial growth in costs of many construction projects, and while the Corporation attempts to mitigate the risk of delays and cost overruns by careful planning and entering into long term contracts when possible, there can be no assurance that significant cost overruns or delays will not occur.

FINANCING ACTIVITIES

In 2009, the Corporation had **net debt increases** of \$209.8 million. **Issuance** of debt comprised of \$150.0 million of 6.50% Debentures due March 7, 2039, \$120.0 million of 6.215% Debentures due March 6, 2024, \$89.7 million of Karratha Financing and \$40.0 million of ATCO Energy Solutions Financing (refer to Business Risks – Financial Markets section). **Redemptions** were comprised of \$125.0 million of 10.20% Debentures due November 30, 2009, \$9.1 million of other long term debt and \$55.8 million of non-recourse long term debt.

On March 27, 2009 CU Inc., a wholly-owned subsidiary of the Corporation, **issued** \$160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2 (for additional details on these shares, refer to Note 16 to the consolidated financial statements for the year ended December 31, 2009). The Corporation had no issues or redemptions of equity preferred shares in 2008.

In 2009 and 2008, there were **no purchases** of Class A non-voting shares under the Corporation's normal course issuer bids. In 2009, **issues** of Class A non-voting shares due to stock option exercises were \$6.4 million compared to \$5.0 million in 2008.

On May 23, 2008, 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 22, 2009. From May 23, 2008, to May 22, 2009, no shares were purchased. The Corporation is applying to the Toronto Stock Exchange to recommence its normal course issuer bid in the first quarter of 2010.

Total **dividends increased** by 6% to \$177.1 million. In 2009, the **quarterly dividend** payment on the Corporation's Class A and Class B Shares was **increased** by \$0.02 to \$0.3525 per share over 2008. On January 14, 2010, the Board of Directors declared the first quarter dividend of \$0.3775 per share. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation decreased the Corporation's cash position by \$4.9 million due to changes in U.K. and Australian exchange rates used for balance sheet translations.

SHORT TERM INVESTMENT POLICY

The Corporation has a long-standing policy not to invest any of its cash balances in asset-backed securities. Cash and short term investment credit risk is reduced by investing approximately 80% in short term money market instruments of Canadian financial institutions and Government of Canada treasury bills as at December 31, 2009.

LINES OF CREDIT

At December 31, 2009, 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	48.0	278.0
Short term committed	600.0	32.0	568.0
Uncommitted	63.7	7.0	56.7
Total	989.7	87.0	902.7

The Corporation's long term committed lines of credit include:

- A \$200 million unsecured revolving extendible term credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility will expire in June 2013, unless extended at the option of the lenders; and

- A \$100 million unsecured revolving extendible term credit facility of ATCO Midstream established in 1999 with a syndicate of Canadian chartered banks and financial institutions. This facility will expire in August 2013, unless extended at the option of the lenders.

The Corporation's short term committed lines of credit comprise of:

- A \$300 million unsecured revolving extendible credit facility of CU Inc. established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for CU Inc.'s commercial paper program and for occasional issues of letters of credit. This facility will expire in July 2010, unless extended at the option of the lenders; and
- A \$300 million unsecured revolving extendible credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for Canadian Utilities' commercial paper program. This facility will expire in July 2010, unless extended at the option of the lenders.

The Corporation's uncommitted lines of credit are primarily used by its subsidiaries for liquidity purposes and for issues of letters of credit. Most of these facilities are unsecured, but some are secured by charges over assets of particular subsidiaries.

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

CONTRACTUAL OBLIGATIONS

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

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
(\$ millions)					
Long term debt	3,120.4	127.8	246.0	189.1	2,557.5
Non-recourse long term debt	408.1	49.0	83.3	70.1	205.7
Interest expense ⁽¹⁾	3,059.2	225.1	404.1	373.4	2,056.6
Operating leases	108.7	18.6	29.4	22.7	38.0
Purchase obligations:					
Alberta Power (2000) coal purchase contracts ⁽²⁾	512.7	51.1	106.2	112.6	242.8
Natural gas purchase contracts ⁽³⁾	71.0	37.8	25.9	7.3	-
Alberta Power (2000), ATCO Power operating and maintenance agreements ⁽⁴⁾	137.6	19.3	35.2	38.1	45.0
Capital Expenditures ⁽⁵⁾	90.9	90.9	-	-	-
Derivatives ⁽⁶⁾	15.5	5.6	5.4	2.4	2.1
Other	2.0	0.8	0.6	0.4	0.2
Total	7,526.1	626.0	936.1	816.1	5,147.9

Notes:

⁽¹⁾ Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2009. Interest payments on debt that has been hedged have been estimated using the hedged rates.

⁽²⁾ Alberta Power (2000) has fixed price long term contracts to purchase coal for its coal-fired generating plants. These costs are recoverable pursuant to the PPAs.

⁽³⁾ Natural gas purchase contracts consist primarily of ATCO Power contracts to purchase natural gas for certain of its natural gas-fired generating plants. ATCO Power has long term offtake agreements with the purchasers of the electricity to recover 78% of these costs. The balance of 22%, related to ATCO Power's Barking generating

plant, is recovered through merchant sales in the U.K. electricity market. The ATCO Power merchant component of its generating plants in Alberta do not have any long term contracts to purchase natural gas.

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

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

⁽⁶⁾ *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2009.*

NET CURRENT AND LONG TERM FUTURE INCOME TAXES

Net current and long term future income taxes at December 31, 2009, were \$471.5 million, an **increase** of \$314.1 million (200%) over 2008. This increase was primarily due to changes in accounting policies relating to rate regulated operations (refer to Changes in Accounting Policies – Rate Regulated Operations section).

Future income taxes are attributable to differences between the financial statement carrying amounts of assets and liabilities and their tax bases. These differences result primarily from recognizing revenue and expenses in different years for financial and tax reporting purposes. Future income taxes will become payable when such differences are reversed through the settlement of liabilities and realization of assets.

BASE SHELF PROSPECTUS

On May 16, 2008, CU Inc. filed a **base shelf prospectus** that permits CU Inc. to issue up to an aggregate of \$1,500.0 million of debentures over the twenty-five month life of the prospectus. During the year ended December 31, 2009, the following debentures were issued:

- on March 6, 2009, CU Inc. issued \$150.0 million of 6.50% Debentures due March 7, 2039, and
- on March 6, 2009, CU Inc. issued \$120.0 million of 6.215% Debentures due March 6, 2024.

The proceeds of these issues were advanced to ATCO Electric, ATCO Gas and ATCO Pipelines to be used to fund capital expenditures, to repay indebtedness and for other general corporate purposes.

Under its base shelf prospectus, CU Inc. has issued \$0.6 billion of debentures to date, leaving \$0.9 billion remaining.

Share Capital

The equity securities of the Corporation consist of Class A Shares and Class B Shares.

At February 16, 2010, the Corporation had outstanding 85,697,380 Class A Shares, 40,162,290 Class B Shares and options to purchase 871,900 Class A Shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON 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 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 non-voting shares authorized for grant in respect of options under Canadian Utilities Limited's stock option plan, 2,989,500 Class A non-voting shares are available for issuance at December 31, 2009. Options may be granted to officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 16, 2010, options to purchase 871,900 Class A Shares were outstanding.

Business Risks

FINANCIAL MARKETS

Over the last year, significant challenges have been experienced in domestic and international financial markets. These challenges have had an impact on the ability of certain borrowers to finance existing operations and capital expenditure programs.

As discussed elsewhere in this MD&A, the Utilities Segment has a capital expenditure program of approximately \$3.5 billion to \$4.5 billion over the next three years. While the current financial situation has not directly impacted the Corporation's ability to fund this capital expenditure program and ongoing operations, future borrowing may be impacted by these financial markets through increased carrying costs and the ability to raise debt and equity capital.

The following financings were completed during 2009:

- In March 2009, CU Inc. completed a \$270 million debenture issue and a \$160 million preferred share issue to fund the 2009 portion of the Utilities Segment's capital expenditure program and to fund scheduled maturities of previous debenture issues;
- On January 28, 2009, ATCO Power executed a credit facility agreement to borrow AUD\$100 million to fund the construction and operations of ATCO Power's new project located in Karratha, Western Australia. The new facility has a term that covers the project's construction period plus five years of operations (Karratha Financing); and
- On June 10, 2009, the Corporation obtained an unsecured \$40.0 million credit facility at an interest rate of 5.72% due June 30, 2014, to finance business activities and project expenditures for ATCO Energy Solutions (ATCO Energy Solutions Financing).

In addition, as at December 31, 2009, the Corporation has cash balances of approximately \$0.8 billion and available committed and uncommitted lines of credit of approximately \$0.9 billion which can be utilized for general corporate purposes.

The Corporation is unable to determine what future changes in the financial markets could occur and how these changes could affect the Corporation. Deterioration in domestic and international economic activity may impact the operations of the Corporation.

COMMODITY AND ENERGY PRICES

Commodity prices, particularly oil and natural gas prices, have fallen significantly since September 2008. These lower prices have had an impact on the Corporation's operations, particularly the lower average Frac Spreads for 2009 on ATCO Midstream's NGL business.

A combination of an increasing power reserve margin (the amount of power supply in excess of demand) and low natural gas prices has led to a decrease in Alberta and U.K. power prices and the commensurate Spark Spreads. This affects approximately 437 MW of merchant power capacity owned in Alberta by ATCO Power and Alberta Power (2000) out of a total Alberta-owned capacity of approximately 1,738 MW and 70 MW of merchant power capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of 262 MW. Refer to Business Risks – Non-Regulated Operations – ATCO Power section for further information.

The Corporation is unable to determine what future changes in commodity and energy markets could occur and how these changes could affect the Corporation.

PENSION PLANS

Employees are required to contribute a percentage of their salary to registered pension plans. The Corporation is required to contribute its share of contributions on behalf of the defined contribution members of the pension plans and to provide the balance of the funding necessary to ensure that benefits will be fully provided for at retirement for the members of the defined benefit pension plans.

Declines in stock and bond markets, changes in actuarial assumptions and additional employee service have created funding deficits in the Corporation's defined benefit pension plans. The Corporation has not made material contributions since April 1, 1996, as a result of the defined benefit plans' surplus positions which existed in the past and were being used to fund the employer's contributions to the defined contribution component of the pension plans.

Based on these changes, material current service and deficit funding contributions will resume in 2010. The actual funding contributions will be determined from actuarial valuations expected to be completed by May 2010. Based on the information currently available, the actual funding contributions for 2010 are expected to be in the range of \$75.0 million to \$90.0 million.

For purposes of any pension funding requirements pertaining to utility operations, the AUC has directed that the cash basis of accounting be used in customer rate applications. Accordingly, the Corporation includes the cost of funding in its rate applications to the AUC, thereby, with the consent of the AUC, recovering approximately 75% of the costs of funding its pension plans from utility customers (refer to Segmented Information – Utilities – Regulatory Developments – Pension Hearing section). Amounts approved by the AUC may vary from the amounts requested. Based on the assumption that the full amounts requested in filed rate applications are approved by the AUC, the net funding contribution amounts (actual funding contributions less recovery from utility customers) are expected to be in the range of \$15.0 million to \$20.0 million. Pension funding contributions do not equate to pension expense for accounting purposes. A description of pension expense can be found in Note 23 of the Corporation's audited financial statements for the year ended December 31, 2009 which can be found on SEDAR at www.sedar.com.

ENVIRONMENTAL MATTERS

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

Greenhouse Gas Emissions

Alberta legislation requires most large emitters to reduce GHG emission intensities by up to 12% as compared to a baseline for the 2003 to 2005 period. For cogeneration and combined cycle facilities, steam production GHG emissions are also subjected to the same 12% reduction target, however these facilities are eligible for special GHG treatment and emissions credits.

Compliance reports for any GHG obligations must be submitted annually to Alberta Environment by March 31 for the previous calendar year. ATCO Power's compliance reporting obligation is expected to result in a settlement amount of 1.1 million tonnes (2008 1.3 million tonnes) including our partners share of the output of the plants emissions (approximately \$16.4 million (2008 - \$19.0 million) when assessed at \$15/tonne). Of this total, approximately 0.8 million tonnes (2008 - 0.9 million tonnes) represented the Energy Segment's share (approximately \$12.0 million (2008 - \$13.6 million) when assessed at \$15/tonne). This settlement amount will be achieved through a combination of approved compliance options including: improved unit performance, emission performance credits, offset credits and technology fund credits. PPA counterparties have reimbursed Alberta Power (2000) for amounts relating to their GHG obligations. Due to lower emissions per unit of output, ATCO Power's gas-fired generating units have minimal exposure to Alberta's GHG regulation and some of the cogeneration facilities generated emission performance credits which can be used for internal compliance as noted above.

ATCO Power participated in a working group established by Alberta Environment tasked with reviewing the method used to determine the GHG obligation for cogeneration units. A new method is expected in early 2010 that will apply to the 2010 reporting year, and could have an impact on ATCO Power's cogeneration plants. Until this methodology is finalized, the impact cannot be determined.

In their most recent industry consultations in mid 2009, the federal government proposed that the regulatory framework of a new Canadian GHG Cap and Trade program would be finalized in 2010. It was expected that the program would be fully implemented by 2012. All carbon emissions would require permits. Permits would be allocated to power generation sector emitters based on historical emissions and ongoing generation. The number of permits provided to this sector would begin at 3% less than the 2006 carbon emission levels and would decrease linearly to a targeted 25% reduction in carbon emission levels by 2020. While not resolved, it was anticipated that a financial compliance mechanism would be available at the outset of the program. In addition to making physical reductions, compliance could also be accomplished by purchasing offsets or through permit trading.

Subsequent to the Copenhagen Conference of the Parties, Canada has aligned its GHG target with the United States at a 17% reduction from 2005 levels by 2020. Further, the Federal Government has stated that it intends to align its form of regulation (either traditional "command and control" or "Cap and Trade") with the approach of the United States. Accordingly, significant regulatory uncertainty and a wide range of potential outcomes remain. ATCO Power continues to monitor and actively engage the Federal Government in this area to manage the associated risks.

It is anticipated that, once the federal GHG program is finalized, the Alberta GHG program will be harmonized to the federal program.

The Barking generating plant in the U.K. complies with the European Union Emissions Trading Scheme (EU-ETS) which is currently in its second phase until the end of 2012. Under this second of three phases, Barking is allocated a free allowance of 1.4 million tonnes towards total annual emissions of 2.8 million tonnes. Barking's long term power purchasers are responsible for 72.5% of the plants emissions. For emissions relating to merchant power generation, Barking purchases allowances in the market concurrently with forward power sales which currently provide a full recovery of these compliance costs.

ATCO Power's Australian generating plants are expected to be regulated by the Australian Government's proposed carbon pollution reduction legislation. All of ATCO Power's Australian plants, both in service and under construction have long term contractual power purchase arrangements allowing full recovery of costs associated with complying with any emissions regulations.

Air Pollutants

Alberta regulation requires coal-fired generating plant operators, including Alberta Power (2000), to monitor mercury emissions and target a capture of at least 70% of the mercury in the coal commencing January 1, 2011. Alberta Environment has approved the Corporation's proposed solution and installation of mercury control equipment at the Battle River and Sheerness generating plants. Installation of this equipment began in 2009 and is expected to be operational in 2010.

The Clean Air Strategic Alliance is conducting a review of air emissions standards (sulphur dioxide, nitrogen oxides, mercury, and particulate matter) for the power generation sector in Alberta. The Energy Segment participates in this process which will develop new air emissions standards for new units and units at the end of their design life (40 years or the end of their PPA term for coal-fired units and 30 years for natural gas-fired units). The new standards are expected to be adopted by Alberta Environment by 2010, and to be effective January 1, 2011.

In May 2008, the federal government and the Canadian Council of Environment Ministers sanctioned a tripartite group (federal, provincial and territorial governments, industry and non-government organizations) to develop a new air management system for sulphur dioxide, nitrogen oxides, particulate matter, volatile organic compounds, mercury, and ground level ozone. They propose to have regulations in place by 2011 with implementation by 2015 for new and existing facilities. The three key elements of this proposal are: national ambient air quality standards set by the federal government, base level equipment performance standards and geographically based air quality management zones. The Energy Segment is represented on the Tripartite Steering Committee through the Canadian Electricity Association and is also participating in the working groups that have been set up to assist with the development of this air management system. It is uncertain how a federal system would impact the existing provincial frameworks.

Cost Recovery

It is anticipated that the PPAs will allow Alberta Power (2000) to recover all of the costs associated with complying with both the federal and Alberta regulations during the PPA terms. An exception to this recovery is for the emissions related to output in excess of the committed capacity in the PPA. The amount of emissions related to output in excess of this committed capacity is minimal. The Corporation's gas-fired fleet should be able to recover the majority of its compliance costs through the market. Market recovery will depend on the degree to which our competitors face similar or greater costs.

The Energy Segment continues to monitor these developments and the impact of complying with any resulting regulations.

Battle River Water Levels

As a result of recent drought conditions, the water levels in the cooling pond used by the Battle River generating plant in its production of electricity have fallen to levels below normal. In 2009, these changes did not result in the need to curtail production of electricity beyond normal summer derates to ensure water temperatures remain within acceptable limits. However, continued drought conditions could result in future curtailments of production. Should the plant experience significant curtailments due to this issue the Battle River PPA provides for force majeure protection and, as a result, the plant's earnings will not be materially affected.

REGULATED OPERATIONS

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

ATCO Electric, ATCO Gas and ATCO Pipelines are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance by the AUC, of costs incurred. The 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 an AUC approved Placeholder rate subject to further review. On December 16, 2009, a Review and Variance decision issued by the AUC confirmed the effective date of removing the Carbon Facility from regulation to be April 1, 2005 (refer to Utilities – Regulatory Developments – ATCO Gas – Carbon Natural Gas Storage Facility section). The approval of the effective removal date of April 1, 2005 results in the finalization of the Placeholder rates for the lease of the Carbon storage facility to ATCO Midstream. However, the City of Calgary and the Utilities Consumer Advocate have filed a joint Leave to Appeal application with the Alberta Court of Appeal regarding the December 16, 2009 decision. As a result of the Leave to Appeal, the effective removal date of the Carbon assets of April 1, 2005 could be impacted, which could also affect the Placeholder lease rate.

As a normal course of operation, the Carbon Facility is subject to drainage. In an effort to protect the Carbon Facility from drainage, ATCO Gas monitors operating pressures and from time to time commissions studies to help protect the integrity of the Carbon Facility. In those instances where it has been deemed necessary, ATCO Gas has undertaken an acreage protection program whereby it acquires the rights to surrounding properties to minimize and eliminate drainage.

Benchmarking

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

The benchmarking report, dealing with the period of 2003-2007, was received on January 23, 2008. In February 2008, the benchmarking report along with an application to adjust the Placeholder rates was filed with the AUC. A hearing was held in December 2009 and a decision is expected in the first quarter of 2010.

All parties continue to support the calculation of fair market value provided in the benchmarking report. The issue in the regulatory proceeding is whether fair market value or some other basis should be used to finalize the Placeholders. If fair market value is used as the basis to finalize the Placeholders for the period 2003-2007 then there will not be a material impact on consolidated earnings.

For the 2008 and 2009 period, a separate regulatory process will occur to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The 2008-2009 proceeding will commence after the completion of the 2003-2007 process.

A further regulatory process to deal with rates for information technology and customer care and billing services provided by ATCO I-Tek for 2010 and beyond has been established and the AUC is expected to set a schedule for this regulatory process after the completion of the 2008-2009 process.

In addition to the rates, this process includes the review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the ATCO Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. On December 11, 2009, the AUC issued a decision approving the implementation of the new Master Service Agreements (excluding the rates therein) with ATCO I-Tek for information technology and customer care and billing services effective January 1, 2010 for an interim period, the term of which will be determined in the upcoming regulatory 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 and one of its affiliates (collectively, Direct Energy), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

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

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

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

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 parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow up are found to be inadequate by the AUC.

Alberta Power (2000)

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

Over 99% of the electricity generated by Alberta Power (2000) is sold pursuant to PPAs. Under the PPAs, Alberta Power (2000) is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, Alberta Power (2000) is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. Alberta Power (2000)'s actual results will vary and depend on performance compared to the forecasts on which the PPAs were based.

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

NON-REGULATED OPERATIONS

ATCO Power

The 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 a small hydro plant. 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 2009, sales from approximately 69% of ATCO Power's generating capacity were subject to long term agreements, while the remaining 31% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. In the first nine months of 2010, these percentages are expected to be approximately the same. On September 30, 2010, the Barking Power

Limited revenue contracts will expire reducing the contracted capacity to approximately 58%. The U.K. and Alberta merchant 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 correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation.

Changes and volatility 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. The Corporation manages this volatility through its adoption of asset optimization strategies in accordance with its risk management policy for bidding its merchant power into both the Alberta and U.K. power markets.

Since October 2004, 27.5% of the power generated at ATCO Power's Barking generating plant has been sold into the U.K. power exchange market. A substantial proportion of the UK electricity market is comprised of vertically integrated companies whose operations include both generation and supply. Market participants trade primarily through structured bilateral contracts and wholesale markets, with smaller volumes traded on a power exchange. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants. The Barking generating plant has a fixed price gas purchase agreement which expires in September 2010 and, as a result, has been able to experience strong margins due to the high market prices for electricity that existed in the first half of 2009. 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 the majority of their non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities has provided a number of guarantees related to ATCO Power's and ATCO Resources' obligations under their respective non-recourse loans associated with certain of their projects. ATCO Power (80%) and ATCO Resources (20%) have a joint venture in the Canadian projects subject to guarantees, excluding McMahon. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest. The guarantees outstanding at December 31, 2009, are described in Note 14 to the consolidated financial statements. To date, Canadian Utilities has not been required to make any payments related to its guaranteed obligations.

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

ATCO Midstream

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

ATCO Midstream is exposed to seasonal natural gas price differentials. The earnings and cash flow from natural gas storage operations will vary as the differences between the price of natural gas in the summer

and the following winter fluctuates. To mitigate this risk ATCO Midstream maintains portfolios of varied contracts, delivery terms, capacities and customers for its storage operations.

In June 2007, the AUC initiated an industry wide review of NGL extraction rights. On February 4, 2009, a decision was issued with respect to NOVA's natural gas transmission system that, in most cases, proposes to transfer ownership of the NGL extraction rights to the receipt point shippers (generally producers) from the border delivery shippers (generally exporters from the province who include ATCO Midstream's suppliers). The decision set out a time frame of three years for implementation and NOVA and industry stakeholders are implementing the decision and its recommendations through NOVA's Tolls, Tariff, Facilities and Procedures process. The earnings and cash flow impact on certain of ATCO Midstream's NGL extraction facilities is uncertain at this time.

ATCO I-Tek

ATCO Electric, ATCO Gas, and ATCO Pipelines purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. The ATCO Utilities recently completed a review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the ATCO Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. Remaining with ATCO I-Tek was determined to be the least expensive option and the recommendation that the ATCO Utilities submitted to the AUC. A decision from the AUC is expected in late 2010 on this recommendation.

Derivative Financial Instruments

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes. For details on the financial instruments in place at December 31, 2009, see Note 24 to the consolidated financial statements.

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

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

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

At inception of a hedge, the Corporation documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Corporation assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and

measures the amount of any hedge ineffectiveness. The Corporation also assesses whether the hedging instrument is expected to be highly effective in the future.

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

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

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

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

- (i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,
 - (ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.
- (b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

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

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

Transactions with Related Parties

On July 1, 2009 the Corporation and its parent, ATCO Ltd. finalized the ATCO Structures & Logistics Transaction. This is related party transaction. For a more detailed description refer to Company Overview – Transaction To Combine ATCO Frontec, ATCO Structures and ATCO Noise Management section.

In other transactions with ATCO Ltd. and its subsidiary corporations, the Corporation sold fuel in the amount of \$1.5 million (2008 - \$2.6 million), provided computer operations and systems development services totaling \$3.9 million (2008 - \$14.1 million), recovered administrative expenses totaling \$7.8

million (2008 - \$1.5 million) and incurred administrative expenses and corporate signature rights totaling \$8.8 million (2008 - \$8.9 million). The Corporation incurred no capital expenditures with related parties (2008 - \$10.3 million that were recorded in property, plant and equipment).

In transactions with entities related through common control, the Corporation incurred advertising, promotion and administrative expenses totaling \$1.4 million (2008 — \$1.4 million).

At December 31, 2009, accounts receivable due from related parties amounted to \$3.8 million (2008 - \$3.3 million) and accounts payable due to related parties amounted to \$3.5 million (2008 - \$6.6 million).

Apart from the ATCO Structures & Logistics Transaction, these transactions are in the normal course of business and under normal commercial terms.

Off-Balance Sheet Arrangements

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

Contingencies

The 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.

Critical Accounting Estimates

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

DEFERRED AVAILABILITY INCENTIVES

Alberta Power (2000) is subject to an incentive/penalty regime related to generating unit availability. The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPAs. Each quarter, management uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPAs to arrive at the amortization for the quarter. As at December 31, 2009, the Corporation

had recorded \$67.1 million of deferred availability incentives. The amortization of deferred availability incentives recorded in revenues amounted to \$16.3 million in 2009.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately \$3.9 million, whereas the low case scenario would have resulted in lower revenues of approximately \$4.1 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 high quality long bond yield rate plus an equity and management premium that reflects the plan asset mix. Recent actuarial guidance suggests that this premium is about 0.5%, which, when added to the high quality long bond yield rate of 7.0% at the beginning of 2009, resulted in an expected long term rate of return of 7.5% for 2009. 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, asset diversification effect on portfolio returns and a recent change in the Corporation's portfolio asset mix policy.

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 recent years to 7.5% in the year ended December 31, 2009. 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.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates that match the timing and amount of expected benefit payments. The liability discount rate has also declined to 6.4% at the end of 2009. The result is an increase in benefit obligations (i.e., an experience loss), which contributes 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% 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 in 2009.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the year ended December 31, 2009, are as follows: for drug costs, 6.5% starting in 2009 grading down over 15 years to 4.5%, and for other medical and dental costs, 4.5% and 4.0%, respectively, for 2009 and thereafter. Combined with lower recent claims experience, the effect of these changes has been to decrease the costs of other post employment benefits.

The effect of changes in these estimates and assumptions is mitigated by an AUC decision to record the costs of employee future benefits when paid rather than accrued. Accordingly, the regulated operations, excluding Alberta Power (2000), recognize a regulatory asset or liability equal to the amount that would otherwise be recorded as expense or income.

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost (income) for 2009 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.

	2009 Pension Benefit Plans		2009 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⁾	-	(4.0)	-	-
1% decrease ⁽¹⁾	-	4.1	-	-
Liability discount rate				
1% increase ⁽¹⁾	(50.3)	(3.2)	(2.3)	(0.2)
1% decrease ⁽¹⁾	61.7	5.2	2.8	0.3
Future compensation rate				
1% increase ⁽¹⁾	12.0	1.9	-	-
1% decrease ⁽¹⁾	(11.1)	(1.7)	-	-
Long term inflation rate				
1% increase ⁽¹⁾⁽²⁾⁽³⁾	48.9	5.8	2.1	0.4
1% decrease ⁽¹⁾⁽³⁾	(41.6)	(5.2)	(1.8)	(0.3)

Notes:

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

Changes in Accounting Policies

Rate Regulated Operations

Effective January 1, 2009, the Canadian Institute of Chartered Accountants (CICA) removed a temporary exemption in its accounting recommendations that permitted assets and liabilities arising from rate regulation to be recognized and measured on a basis other than in accordance with the primary sources of GAAP. Previously, the Corporation followed Canadian GAAP recommendations, which were similar to standards issued by the Financial Accounting Standards Board (FASB) in the United States, which provide guidance on the recognition and measurement of assets and liabilities arising from rate regulation. As permitted by Canadian GAAP, the Corporation has applied standards issued by FASB as another source of Canadian GAAP. This change in accounting policy has been adopted prospectively with changes identified below. Although the standards are similar, key differences are outlined below.

The reserves for future removal and site restoration costs for the utility operations, which were previously netted against property plant and equipment, have been reclassified to non-current regulatory liabilities, resulting in an increase to the Corporation's total assets and total liabilities. The Corporation reclassified \$376.2 million at January 1, 2009, corresponding to these reserves.

Previously, depreciation expense for property, plant and equipment included a provision for future removal and site restoration costs for the utility operations. An amount corresponding to this provision is incorporated into rates charged to customers and was previously recognized in revenues. Under the new method of accounting, the Corporation does not recognize this amount in depreciation and amortization expense and revenues. The Corporation now recognizes operation and maintenance expense and revenues as actual removal and site restoration costs are incurred. As a result of the change in accounting, for the three months ended December 31, 2009, depreciation and amortization expense was \$13.8 million lower, revenues were \$5.9 million lower, and operations and maintenance expense was \$7.9 million higher, resulting in no change in earnings. For the year ended December 31, 2009, depreciation and amortization expense was \$54.0 million lower, revenues were \$36.4 million lower, and operations and maintenance expense was \$17.6 million higher, resulting in no change in earnings.

Effective January 1, 2009, the Corporation also adopted the CICA recommendations requiring the recognition of future income tax assets and liabilities as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers in the utility operations. As a result of adopting these recommendations, the Corporation recorded future income tax liabilities and non-current regulatory assets of \$255.6 million at January 1, 2009.

Concurrent with the changes in accounting for rate regulated operations noted above, the Corporation changed its presentation of changes in regulatory accounts within the statement of cash flows. Certain items relating to changes in rate regulated assets and liabilities that were previously included in investing and financing activities are now reported in operating activities. The inclusion of changes in the non-current regulatory assets and liabilities in operating activities provides more relevant information on the activities of the Corporation.

Goodwill and Intangible Assets

Effective January 1, 2009, the Corporation adopted the CICA recommendations for goodwill and intangible assets which established standards for the recognition, measurement, presentation and disclosure of goodwill and intangible assets (including internally developed intangible assets).

This change in accounting has been adopted retrospectively and had the following effect on the consolidated financial statements for the year ended December 31, 2009 and December 31, 2008:

- (a) Restatement of opening retained earnings at January 1, 2008, to recognize the prior years' earnings effect of amounts capitalized prior to 2008 that do not meet the definition of intangible assets as now defined by GAAP (refer to Note 8 to the consolidated financial statements for the year ended December 31, 2009).
- (b) Restatement of depreciation and amortization expense and future income taxes for 2008 for the effect of amounts capitalized and amortized in 2008 and prior periods that do not meet the definition of assets as now defined by GAAP. The amounts are not material.
- (c) Restatement of opening accumulated other comprehensive income at January 1, 2008, for the effect of amounts capitalized prior to 2008 that do not meet the definition of assets as now defined by GAAP. The amounts are not material.
- (d) Reclassification of \$209.4 million included in property, plant and equipment and other assets to intangible assets on the balance sheet at December 31, 2008.

- (e) Restatement of operating activities in the statement of cash flows for the impact of changes resulting from (b) above and a reclassification within investing activities of \$51.7 million from purchases of property, plant and equipment to purchases of intangibles for 2008.

Financial Instruments Disclosure

The CICA has issued revisions to the disclosures for financial instruments requiring classifications of fair value measurement of financial instruments using a three level fair value hierarchy reflecting the significance of the inputs used in making the measurements. These revisions are effective for the Corporation's annual reporting for the year ended December 31, 2009. For a description of the financial instruments or the fair value hierarchy, refer to Note 1 to the consolidated financial statements for the year ended December 31, 2009.

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards

The Canadian Accounting Standards Board confirmed in 2008 that the use of International Financial Reporting Standards (IFRS) by publicly accountable enterprises will be required in 2011. The Corporation will need to begin reporting under IFRS in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to Canadian GAAP, but there could be significant differences in recognition, measurement and disclosures that will need to be addressed.

The Corporation has established a Steering Committee, a project team, and working groups to review the adoption of IFRS. The project team and working groups provide position papers and regular updates to management, the Steering Committee and the Audit Committee. Education sessions have been, and will continue to be, provided for employees, senior management and the Audit Committee to increase knowledge and awareness of IFRS and its impacts.

The Corporation is participating in various industry groups, including the Canadian Energy Pipeline Association, the Canadian Gas Association and the Canadian Electricity Association. The Corporation participated in a collaborative process which culminated in the AUC issuing regulations that summarize the rate making accounting procedures and requirements to be used by utilities as a result of adopting IFRS. The direction provided in the AUC regulations will allow the Corporation to proceed with cost efficient changes to its financial reporting computer systems. The AUC announced that it will periodically review and amend the material contained in the regulations as circumstances warrant.

The Corporation's IFRS Conversion Project consists of three phases:

- **Assessment and Diagnostic** – This phase involves high level assessment to identify the key areas impacted by the transition to IFRS and to identify the International Financial Reporting Standards and Interpretations of those standards applicable to the Corporation. It also involves assessing each standard and interpretation to identify the changes required to existing accounting policies, information systems and business process. This phase is now complete.
- **Design and Planning** – This phase involves assessing alternative accounting policies and planning changes that need to be made to financial covenants and internal controls. Preliminary estimates are being prepared to show the impact of the quantitative impact of the new standards. Draft financial statements and notes are prepared (without any numbers) to identify additional disclosure requirements. This phase is substantially complete.
- **Implementation and Review** – This phase involves making changes in accounting policies and procedures and financial information systems and training staff on the implementation of the new standards. Financial information in accordance with IFRS will be collected in 2010 to allow for comparative reporting in 2011. This phase is in progress.

Position papers on issue-specific accounting differences between Canadian GAAP and IFRS and the impact on financial reporting computer systems are substantially complete and they have been discussed with the Corporation's external auditor. The Corporation has also made most of the necessary changes to its financial reporting computer systems and has completed its review of the impact of IFRS on financial covenants. As a number of the IFRS standards are changing, the position papers and the impact of IFRS on financial covenants will be updated to reflect any changes resulting from the final standards. The Corporation is currently evaluating the impact of IFRS on internal controls over financial reporting. An evaluation of the financial impact of the issues identified in the assessment and diagnostic phase was completed in 2009.

The Corporation reviews discussion papers, exposure drafts and standards released by the International Accounting Standards Board (IASB) and the International Financial Reporting Interpretations Committee. On July 23, 2009, the IASB issued an exposure draft on rate regulated activities (the Exposure Draft) and recently, IASB staff have issued a summary of their analysis of the responses to the Exposure Draft. The IASB staff is proposing that if the IASB decides to continue with the project that they approve further study and analysis of the issues raised and a revised timeline. The proposed timeline would result in a final standard being issued in the second half of 2011. The Corporation is currently evaluating the impact of the possible changes to the Exposure Draft and the timeline for issuing a final standard, on the Corporation's IFRS Conversion Project. Financial impacts cannot be reasonably determined at this time.

Based on initial assessments, the Corporation has identified that the following areas have the greatest potential impact on the Corporation's accounting: joint arrangements, leases, asset impairment, employee benefits, regulatory accounting and customer contributions. There will also be a significant amount of effort to comply with the IFRS' requirements for initial adoption of IFRS.

The Corporation is party to numerous joint arrangements which currently use proportionate consolidation as the appropriate accounting treatment. Under proportionate accounting, the Corporation records its proportionate share of the assets, liabilities, revenues and expenses of the joint arrangement. Under the recent IFRS exposure draft on joint arrangements, if the joint arrangement (and not the Corporation) has indirect interests to share in the 'net' common outcome expected to be generated from a group of underlying assets and liabilities under the joint control of all of the venturers, the Corporation would account for those joint arrangements using equity accounting and report the investment in joint venture on the balance sheet and equity earnings on the statement of earnings.

Impairment under Canadian GAAP is a two step approach. First an entity determines if the recoverable amount (undiscounted cash flow) is less than the carrying value and, only if it is, then it determines if the fair value (selling price or discounted cash flow) is less than carrying amount. Impairment under IFRS is a one step approach where the entity considers whether the recoverable amount (higher of fair value less cost to sell or value in use discounted cash flow) is less than carrying amount. The amount of any impairment loss on transition to IFRS has not yet been determined.

The Corporation is currently party to a number of contracts with customers that will be deemed to be finance leases under IFRS. Under Canadian GAAP, the total revenue received from the customer is recorded on the statement of earnings and the related property, plant and equipment is depreciated evenly over the asset's useful life. Under IFRS, property, plant and equipment of a project which is deemed to be a finance lease will effectively be removed from the balance sheet and replaced with a present value finance lease receivable for the lease payments to be received over the remaining life of the arrangement. Payments received from the customer are allocated between revenue and principal payment based on a mortgage style calculation.

Employee benefits consist of pensions and other retirement benefits, including life insurance and medical care. IFRS allows an entity to recognize all experience and transitional gains and losses to retained earnings as at January 1, 2010. IFRS also allows an entity to subsequently recognize actuarial gains and losses in other comprehensive income. The amortization of the net pension gain that would be required under Canadian GAAP is not made under IFRS. The balance sheet also reflects the pension transition adjustment, which was initially recognized upon a change in Canadian GAAP in 2000, to retained earnings as at January 1, 2010.

Under the recent Exposure Draft on rate regulated activities identified above, the Corporation would have to record all regulatory assets and liabilities, including those pertaining to expected decisions on rate or tariff applications from the AUC, using a weighted average probability method. The Corporation does not record regulatory assets or liabilities for rate or tariff applications until it receives a decision from the AUC. In addition, all regulatory assets and liabilities, including the one for the future income tax liability, must be measured at their expected present value. However under IFRS, the future income tax liability is measured at cost. Under Canadian GAAP, both the future income tax liability and the related regulatory asset are measured at cost and not expected present value. Therefore under the Exposure Draft, the methodology for measuring the future income tax liability and the related regulatory asset are different. The IFRS exposure draft, as currently written, is not expected to materially change the recognition and measurement of other regulatory assets and liabilities under Canadian GAAP.

The Corporation obtains contributions from utility customers to construct assets in situations where it is not economic to provide service to the customer at the approved rate charged to other customers. Under IFRS, this contribution would be accounted for as deferred revenue on the basis that there is no stand-alone value for utility customers who provide these contributions without ongoing service by the Corporation. The deferred revenue will be amortized over the life of the related asset. Under Canadian GAAP, the contributions are deducted from property plant and equipment and amortized over the life of the related asset. This effectively reclassifies the unamortized customer contributions from an offset to property plant and equipment to a liability on the balance sheet.

Quarterly Results of Operations

SELECTED INFORMATION

(\$ millions except per share data)	For the Three Months Ended ^{(1) (2) (3)}				
	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Total
2009					
Revenues	768.6	602.7	537.1	675.6	2,584.0
Earnings attributable to Class A and Class B Shares	145.4	73.2	120.9	127.1	466.6
Earnings per Class A and Class B Share	1.16	0.58	0.96	1.01	3.71
Diluted earnings per Class A and Class B Share	1.16	0.58	0.96	1.01	3.71
Adjusted Earnings ⁽⁴⁾	148.3	73.5	76.7	129.1	427.6
Adjusted Earnings per Class A and Class B Share ⁽⁴⁾	1.18	0.59	0.61	1.02	3.40
2008 ⁽⁵⁾					
Revenues	740.6	655.6	638.4	744.3	2,778.9
Earnings attributable to Class A and Class B Shares	150.3	82.7	67.0	114.5	414.5
Earnings per Class A and Class B Share	1.20	0.66	0.53	0.91	3.30
Diluted earnings per Class A and Class B Share	1.19	0.66	0.53	0.91	3.29
Adjusted Earnings ⁽⁴⁾	150.0	70.8	71.6	110.8	403.2
Adjusted Earnings per Class A and Class B Share ⁽⁴⁾	1.20	0.56	0.57	0.88	3.21

Notes:

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

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

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

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

⁽⁵⁾ Certain numbers have been restated to reflect changes in accounting policies relating to goodwill and intangible assets (refer to Changes in Accounting Policies - Goodwill and Intangible Assets section).

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

- unplanned and planned outages affecting availability in ATCO Power's and Alberta Power (2000)'s generating plants;
- the timing of utility rate decisions;
- amount of franchise fees collected by ATCO Gas on behalf of municipalities;
- fluctuations in temperatures, natural gas prices, electricity prices and related Spark Spreads in Alberta and the U.K.;
- changes in market conditions in ATCO Midstream's NGL and storage operations;

- the impact of the ATCO Structures & Logistics Transaction (refer to Company Overview – Transaction to Combine ATCO Frontec, ATCO Structures and ATCO Noise Management section);
- exchange rates;
- increase in rate base in the Utilities Segment;
- Carbon Facility decisions;
- the impact of adopting new accounting standards for the recognition of revenues and expenses for the regulated assets in the Utilities Segment (refer to Changes in Accounting Policies – Rate Regulated Operations section);
- mark-to-market adjustments in ATCO Power;
- H.R. Milner Income Tax Reassessment;
- Other Post Employment Benefits;
- Federal Court of Appeal Decision - Mining Assets;
- 2008 Tax Assessment; and
- changes in share appreciation rights expense due to changes in ATCO Class I non-voting share and the Corporation's Class A non-voting share prices.

Fourth Quarter 2009

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

Segmented Revenue (\$ millions)	For the Three Months Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Utilities	367.9	330.4	11%
Energy	296.1	335.0	(12%)
Corporate & Other	52.7	128.8	(59%)
Intersegment eliminations	(41.1)	(49.9)	18%
Revenues	675.6	744.3	(9%)

Notes:

- (1) There were no discontinued operations or extraordinary items during these periods.
- (2) Due to certain factors, revenues for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.
- (3) The above data has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

Fourth quarter **revenues decreased** by \$68.7 million primarily due to the impact of the ATCO Structures & Logistics Transaction, lower merchant performance in ATCO Power's Alberta generating plants due to lower pool prices in the Alberta electricity market and unfavourable merchant conditions in ATCO Power's U.K. operations. These decreases were partially offset by the timing and demand for natural gas storage resulting in higher storage fees in ATCO Midstream, the impact of increased rate base in ATCO Electric and ATCO Gas (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – 2009 and 2010 General Tariff Application section and ATCO Gas – 2008 and 2009 General Rate Application section) and the impact on ATCO Gas and ATCO Electric of the 2009 Generic Cost of Capital Decision (refer to Segmented Information - Utilities – Regulatory Developments – Generic Cost of Capital section).

SEGMENTED EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES	For the Three Months Ended December 31 ^{(1) (2) (3) (4)}		
	2009	2008	Change to 2009 (2009-2008)
(\$ millions)			
Utilities	52.8	45.3	17%
Energy	72.5	65.9	10%
Corporate & Other	1.7	3.5	(51%)
Intersegment eliminations	0.1	(0.2)	150%
Earnings attributable to Class A and Class B Shares	127.1	114.5	11%
Earnings per Class A and Class B Share	1.01	0.91	11%
Diluted earnings per Class A and Class B Share	1.01	0.91	11%
Adjusted earnings per Class A and Class B Share	1.02	0.88	16%

Notes:

- ⁽¹⁾ There were no discontinued operations or extraordinary items during these periods.
- ⁽²⁾ Due to certain factors, earnings and Adjusted Earnings for any quarter are not necessarily indicative of operations on an annual basis. These factors include the seasonal nature of the Corporation's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, changes in NGL prices and natural gas costs and the timing of rate decisions.
- ⁽³⁾ The above data (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B Share) has been extracted from the financial statements, which have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.
- ⁽⁴⁾ Certain numbers have been restated to reflect changes in accounting policies relating to goodwill and intangible assets (refer to Changes in Accounting Policies - Goodwill and Intangible Assets section).

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

(\$ millions)	For the Three Months Ended December 31				
	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Total
2009					
Earnings attributable to Class A and Class B Shares	52.8	72.5	1.7	0.1	127.1
Mark-to-Market Adjustment ⁽¹⁾	-	2.0	-	-	2.0
Adjusted Earnings	52.8	74.5	1.7	0.1	129.1
2008					
Earnings attributable to Class A and Class B Shares	45.3	65.9	3.5	(0.2)	114.5
Mark-to-Market Adjustment ⁽¹⁾	-	1.1	-	-	1.1
2008 Tax Assessment ⁽¹⁾	(3.3)	-	-	-	(3.3)
Other Post Employment Benefits ⁽¹⁾	-	(1.5)	-	-	(1.5)
Adjusted Earnings	42.0	65.5	3.5	(0.2)	110.8

Note:

- ⁽¹⁾ Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.

Fourth quarter **earnings increased** by \$12.6 million (11%) over 2008, including the impact of adjustments identified in the Significant Non-Operating Financial Items section.

Fourth quarter **Adjusted Earnings increased** by \$18.3 million (17%) over 2008, primarily attributable to the timing and demand for natural gas storage in ATCO Midstream, the impact of the 2009 Generic Cost of Capital Decision and lower operating and maintenance costs as compared to amounts that were included in ATCO Electric's and ATCO Gas' customer rates primarily due to cost efficiencies. These increases were partially offset by lower merchant performance in ATCO Power's Alberta generating plants due to lower Spark Spreads in the Alberta electricity market, unfavourable merchant performance in ATCO Power's U.K. operations, higher financing costs in ATCO Electric compared to amounts included in customer rates and the impact of the ATCO Structures & Logistics Transaction. Adjusted Earnings for the Corporation's 24.5% share of equity earnings in ASL for the three months ended December 31, 2009 was lower than the Adjusted Earnings for ATCO Frontec in the corresponding period of 2008.

Alberta Power Pool electricity prices for the three months ended December 31, 2009, averaged \$46.27 per MWh, compared to average prices of \$95.20 per MWh in 2008. Natural gas prices for the three months ended December 31, 2009, averaged \$4.31 per GJ, compared to average prices of \$6.35 per GJ in 2008. The consequence of these changes in electricity and natural gas prices was an average Spark Spread of \$13.93 per MWh for the three months ended December 31, 2009, compared to \$47.59 per MWh in 2008.

During the three months ended December 31, 2009, the **deferred availability incentive** account **increased** by \$3.7 million to \$67.1 million, mainly due to reduced outages in the quarter net of amortization. During the three months ended December 31, 2009, the amortization of deferred availability incentives, recorded in revenues, increased by \$0.2 million to \$3.7 million, compared to 2008.

Interest and other income for the fourth quarter **decreased** by \$5.0 million to \$9.6 million primarily as a result of the lower rates of interest earned on cash balances and the mark-to-market adjustment in ATCO Power.

OTHER EXPENSES

For the Three Months Ended December 31

(\$ millions)	For the Three Months Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Operating expenses:			
Natural gas supply	4.3	3.6	19%
Purchased power	14.3	14.9	(4%)
Operation and maintenance	233.5	300.4	(22%)
Selling and administrative	80.2	87.2	(8%)
Franchise fees	43.9	42.5	3%
	376.2	448.6	(16%)
Depreciation and amortization expenses	80.4	100.1	(20%)
Interest	60.7	60.3	1%
Income taxes	34.1	27.2	25%
Dividends on equity preferred shares	10.8	8.2	32%

Fourth quarter **operating expenses decreased** by \$72.4 million (16%) compared to 2008. Operation and maintenance expenses were lower, primarily as a result of the ATCO Structures & Logistics Transaction

and lower fuel costs in ATCO Power's Alberta and U.K. generating facilities. These decreases were partially offset by higher operating costs due to the impact of applying new accounting standards in the Utilities Segment relating to the treatment of future removal and site restoration costs for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). Selling and administrative expenses were lower mainly due to the impact of the ATCO Structures & Logistics Transaction partially offset by high selling and administrative expenses in the Utilities Segment primarily as a result of higher employment costs due to growth.

Fourth quarter **depreciation and amortization expenses decreased** by \$19.7 million (20%) compared to 2008, primarily due to the impact of applying new accounting standards in the Utilities Segment relating to the treatment of future removal and site restoration costs for rate regulated assets (refer to Changes in Accounting Policies – Rate Regulated Operations section). These decreases were partially offset by capital additions in 2008 and 2009 in the Utilities Segment.

Interest expense for the fourth quarter **increased** by \$0.4 million (1%) over 2008, primarily due to increased amounts of debt outstanding (net of redemptions) resulting from new financings issued in 2008 and 2009 to fund capital expenditures in the Utilities Segment, partially offset by the repayment of ATCO Power's non-recourse financings in 2008 and 2009.

Income taxes in the fourth quarter **increased** by \$6.9 million (25%) over 2008, mainly due to the impact of lower tax deductions in the Utilities Segment in 2009 due to the use of the flow-through tax methodology and higher earnings before income taxes.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CASH FLOW

For the Three Months Ended
December 31

(\$ millions)	For the Three Months Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Cash position, beginning of period	983.8	946.1	4%
Cash provided by (used in):			
Operating activities:			
Funds Generated by Operations	229.1	249.1	(8%)
Changes in non-cash working capital	(65.9)	(79.2)	17%
Cash flow from operations	163.2	169.9	(4%)
Investing activities	(196.2)	(317.4)	38%
Financing activities	(153.4)	(68.8)	(123%)
Foreign currency impact on cash balances	(1.4)	(3.2)	56%
Cash position, end of period	796.0	726.6	10%

OPERATING ACTIVITIES

Funds Generated by Operations decreased by \$20.0 million (8%) compared to 2008, primarily due to lower cash earnings and decreased deferred availability incentives in Alberta Power (2000). **Cash flow from operations** for the fourth quarter **decreased** by \$6.7 million (4%) compared to 2008, primarily due to decreases in Funds Generated by Operations partially offset by changes in non-cash working capital.

INVESTING ACTIVITIES

Investing in the fourth quarter **decreased** by 38% compared to 2008, primarily as a result of lower capital expenditures and changes in non-cash working capital, partially offset by lower contributions by utility customers for extensions to plant. **Decreases in capital expenditures** reflect decreased investment in transmission and distribution projects in ATCO Electric, natural gas distribution projects in ATCO Gas and natural gas transmission projects in ATCO Pipelines.

FINANCING ACTIVITIES

In the fourth quarter, the Corporation had **net debt decreases** of \$113.8 million. **Issuance** of debt comprised of \$23.7 million of Karratha Financing. **Redemptions** included \$125.0 million of 10.20% Debentures due November 30, 2009, \$0.3 million of other long term debt and \$12.2 million of non-recourse long term debt.

In the fourth quarter, the Corporation had **no issues or redemptions** of equity preferred shares.

In the fourth quarter of 2009 and 2008, there were **no purchases** of Class A Shares under the Corporation's normal course issuer bids. In the fourth quarter, **issues** of Class A Shares due to stock option exercises amounted to \$3.7 million, compared to \$0.1 million from the corresponding period in 2008.

In the fourth quarter, total **dividends paid to Class A and Class B share owners increased** by 6% to \$44.3 million over the same period in 2008. In the fourth quarter, the **quarterly dividend** payment on the Corporation's Class A and Class B Shares **increased** by \$0.02 to \$0.3525 per share.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation decreased the Corporation's cash position by \$1.4 million due to changes in U.K. and Australian exchange rates used for balance sheet translations.