



An **ATCO** Company

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

CU Inc.
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).

AESO means the Alberta Electric System Operator.

ATCO I-Tek means ATCO I-Tek Inc., a wholly-owned subsidiary of Canadian Utilities Limited.

ATCO Midstream means ATCO Midstream Ltd., a wholly-owned subsidiary of Canadian Utilities.

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.

Canadian Utilities means Canadian Utilities Limited.

Capacity Charges means a form of compensation to the owners of PPA generating units for their fixed operating and capital costs including return on rate base (debt and equity) and income taxes.

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 CU Inc. and, unless the context otherwise requires, includes its subsidiaries.

Excess Energy Charges means a form of compensation to the owners of PPA generating units for electrical energy supplied in excess of the committed output capacity defined in the PPA.

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.

IFRS means International Financial Reporting Standards.

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.

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.

Company Overview

CU Inc. was incorporated under the laws of Canada on March 12, 1999. The Corporation has assets of approximately \$6.6 billion and more than 4,100 employees.

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

The Corporation operates in the following 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.

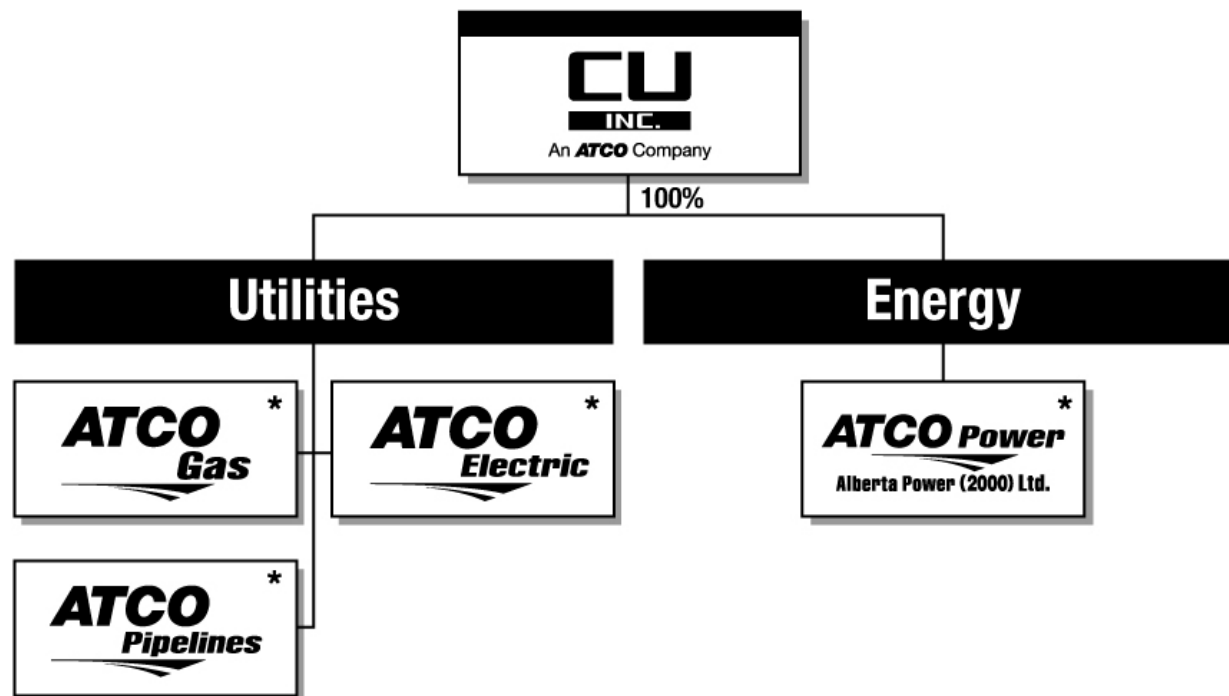
The **Energy** Segment includes:

- the regulated supply of electricity by Alberta Power (2000).

Effective the third quarter of 2009, the **Power Generation** Segment has been renamed the **Energy** Segment.

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 23 to the consolidated financial statements.

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.

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.

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” and “Adjusted Earnings” 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

	For the Year Ended December 31		
	2009	2008	2007
(\$ millions, except per share data and % return on equity) ⁽¹⁾⁽²⁾⁽⁹⁾			
Revenues	1,677.3	1,573.4	1,414.2
Earnings attributable to Class A and Class B shares	262.6	200.3	177.3
Adjusted Earnings ⁽³⁾	245.8	192.5	163.2
Total assets	6,592.2	5,405.2	4,879.0
Long term debt	2,827.4	2,683.2	2,459.4
Equity preferred shares	405.0	245.0	245.0
Class A and Class B share owners' equity	2,038.8	1,815.4	1,674.8
Return on equity	13.6	11.5	11.2
Cash flow from operations ⁽¹⁰⁾	508.0	498.6	429.8
Funds generated by operations ⁽¹⁰⁾	534.9	497.1	415.5
Capital expenditures	791.8	878.4	615.4
Cash dividends declared per share:			
Series Preferred Shares:			
Series 1 ⁽⁴⁾	1.15	1.15	0.71
Series 2 ⁽⁵⁾	1.14	-	-
Series Second Preferred Shares:			
Series Q ⁽⁶⁾	-	-	0.68
Series R ⁽⁶⁾	-	-	0.61
Series S ⁽⁶⁾	-	-	0.77
Series U ⁽⁷⁾	1.09	1.09	1.09
Series V ⁽⁸⁾	1.18	1.18	1.28

Notes:

- ⁽¹⁾ There were no discontinued operations or extraordinary items during these periods.
- ⁽²⁾ The above data (other than Adjusted Earnings, Funds generated by operations and return on equity) has been extracted from the financial statements, which have been prepared in accordance with GAAP, and the reporting currency is the Canadian dollar.
- ⁽³⁾ Refer to Significant Non-Operating Financial Items section for a description of adjustments to obtain Adjusted Earnings.
- ⁽⁴⁾ Series 1 Preferred Shares were issued on April 18, 2007.
- ⁽⁵⁾ Series 2 Preferred Shares were issued on March 27, 2009.
- ⁽⁶⁾ Series Second Preferred Shares Q, R and S were redeemed on May 18, 2007.
- ⁽⁷⁾ 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.
- ⁽⁸⁾ 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.
- ⁽⁹⁾ As all the Class A and Class B shares of the Corporation are owned by Canadian Utilities Limited, the disclosure of earnings per share is not provided as it is not considered to be meaningful.
- ⁽¹⁰⁾ Certain numbers have been restated to reflect changes in accounting policies relating to rate regulated operations (refer to Changes in Accounting Policies – Rate Regulated Operations section).

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	262.6	200.3
H.R. Milner Income Tax Reassessment ⁽¹⁾	(16.8)	-
Federal Court of Appeal Decision- Mining Assets ⁽²⁾	-	(3.0)
Other Post Employment Benefits ⁽³⁾	-	(1.5)
2008 Tax Assessment ⁽⁴⁾	-	(3.3)
Adjusted Earnings	245.8	192.5

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

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

(1) H.R. Milner Income Tax Reassessment

In 2006, 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.

(2) 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 Corporation'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

(3) 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. Under the new method of allocation, the OPEB liability and non-current regulatory assets of the regulated operations, excluding Alberta Power (2000), increased by \$10.4 million. Pursuant to an AUC decision effective January 1, 2000, the regulated operations, excluding Alberta Power (2000), are required to expense contributions for other post employment benefit and certain other defined benefit pension plans as paid. Consequently, there was no change to their earnings for the three months and year ended December 31, 2008. The difference between the amounts accrued and paid is deferred in non-current regulatory assets. The OPEB liability for Alberta Power (2000) decreased which resulted in an increase to earnings of \$1.5 million, which was recorded in the fourth quarter of 2008.

(4) 2008 Tax Assessment

In 2008 the Corporation received a favorable 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 **increased** by \$103.9 million (7%) over 2008. This increase was primarily attributable to a \$106.6 million (8%) increase in the Utilities Segment, partially offset by a \$2.7 million (1%) decrease in the Energy Segment.

The **increase in revenues** was primarily attributable to 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 higher AUC approved customer rates resulting from the ATCO Pipelines' negotiated settlement decision for 2008 and 2009 (ATCO Pipelines' Negotiated Settlement). These increases in revenues were partially offset by 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).

Earnings in 2009 were \$262.6 million, an **increase** of \$62.3 million (31%), over 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings were \$245.8 million, an **increase** of \$53.3 million (28%), over 2008. The primary reasons for increased 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 (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Gas – Carbon Natural Gas Storage Facility section). These increases in Adjusted Earnings were partially offset by higher financing costs in ATCO Electric compared to amounts included in customer rates.

Interest and other income in 2009 **increased** by \$9.8 million to \$36.3 million over 2008, mainly due to 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) partially offset by lower rates of interest earned on cash balances.

CONSOLIDATED EXPENSES

(\$ millions)	For the Year Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Operating expenses:			
Natural gas supply	1.0	2.6	(62%)
Purchased power	54.1	54.1	0%
Operation and maintenance	450.3	409.2	10%
Selling and administrative	265.9	233.9	14%
Franchise fees	163.5	175.2	(7%)
	934.8	875.0	7%
Depreciation and amortization	244.9	299.1	(18%)
Interest	200.3	181.5	10%
Income taxes	51.5	32.7	57%
Dividends on equity preferred shares	19.5	11.3	73%

Operating expenses in 2009 **increased** by \$59.8 million (7%) over 2008. Operation and maintenance expenses were higher 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). 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. Decreased franchise fees, recovered on a flow through basis, were paid in ATCO Gas.

In 2009, **depreciation and amortization expenses decreased** by \$54.2 million (18%) 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 \$18.8 million (10%) 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.

In 2009, **income taxes increased** by \$18.8 million (57%) over 2008, primarily due to higher earnings before income taxes and a \$6.1 million income tax adjustment in ATCO Gas as a result of the removal of the Carbon Facility from regulation, partially offset by a \$7.8 million tax adjustment as a result of the H.R. Milner Income Tax Reassessment in Alberta Power (2000).

Dividends on equity preferred shares in 2009 **increased** by \$8.2 million (73%) over 2008, as a result of the issue of \$160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2 on March 27, 2009.

SEGMENTED INFORMATION

(\$ millions)	For the Year Ended December 31				
	Utilities	Energy	Corporate & Other	Intersegment Eliminations	Total
2009					
Revenues	1,367.5	309.9	-	(0.1)	1,677.3
Earnings attributable to Class A and Class B Shares	195.4	67.1	0.1	-	262.6
H.R. Milner Income Tax Reassessment (1)	-	(16.8)	-	-	(16.8)
Adjusted Earnings	195.4	50.3	0.1	-	245.8
2008					
Revenues	1,260.9	312.6	-	(0.1)	1,573.4
Earnings attributable to Class A and Class B Shares	148.6	51.4	0.3	-	200.3
Federal Court of Appeal Decision – Mining Assets (2)	(2.2)	(0.8)	-	-	(3.0)
Other Post Employment Benefits (3)	-	(1.5)	-	-	(1.5)
2008 Tax Assessment (4)	(3.3)	-	-	-	(3.3)
Adjusted Earnings	143.1	49.1	0.3	-	192.5

Notes:

(1) (2) (3) (4) 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 \$2.7 million (1%) to \$309.9 million compared to 2008. This decrease was primarily as a result of lower Excess Energy Charges, partially offset by higher revenues due to increased Capacity Charges due to adjustments to indices for prior periods and increased amortization of deferred availability incentives.

Earnings for 2009 were \$67.1 million, an **increase** of \$15.7 million (31%) over 2008, including the impact of the adjustments identified in the Significant Non-Operating Financial Items section.

Adjusted Earnings were \$50.3 million, an **increase** of \$1.2 million (2%), compared to 2008. The primary reasons for the increase were a reduction in income tax expense relating to the treatment of major maintenance expense in Alberta Power (2000), higher Capacity Charges due to adjustments to indices for prior periods at the Battle River and Sheerness generating plants and increased amortization of deferred availability incentives. These increases in Adjusted Earnings were partially offset by lower Excess Energy Charges.

Availability of the generating plants is set forth below:

	For the Year Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Alberta Power (2000) ⁽¹⁾ Canada	91.9%	91.8%	0.1%

Note:

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

Recent 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.

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.

Liquidity and Capital Resources

A major portion of the Corporation's operating income and funds generated by operations is generated from its utility operations. The Corporation uses 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	(9.0)	0.3	(3,100%)
Cash provided by (used in)			
Operating activities:			
Funds generated by operations	534.9	497.1	8%
Changes in non-cash working capital	(26.9)	1.5	(1,893%)
Cash flow from operations	508.0	498.6	2%
Investing activities	(695.0)	(670.0)	4%
Financing activities	260.1	162.1	60%
Cash position, end of period	64.1	(9.0)	812%

OPERATING ACTIVITIES

Funds generated by operations were \$534.9 million in 2009, an **increase** of \$37.8 million (8%) over 2008. This increase was primarily due to higher cash earnings partially offset by decreased availability incentives in Alberta Power (2000). In 2009, **cash flow from operations** was \$508.0 million, an **increase** of \$9.4 million (2%) compared to 2008. This increase was primarily due to higher funds generated by operations, partially offset by changes in non-cash working capital.

INVESTING ACTIVITIES

In 2009, **cash used in investing activities increased** by 4% 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 \$86.6 million, compared to 2008. This decrease was primarily due to decreased investment in natural gas distribution projects in ATCO Gas and distribution projects in ATCO Electric, partially offset by increased investment in natural gas transmission projects in ATCO Pipelines.

Capital Expenditures

(\$ millions)	For the Year Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Utilities	776.1	852.6	(9%)
Energy	15.7	25.8	(39%)
	791.8	878.4	(10%)

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately \$1.2 billion in 2010, an **increase** of \$0.4 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 \$145.0 million. **Issuances** of debt were comprised of \$150.0 million of 6.50% Debentures due March 7, 2039 and \$120.0 million of 6.215% Debentures due March 6, 2024. **Redemptions** were comprised of \$125.0 million of 10.20% Debentures which matured on November 30, 2009.

On March 27, 2009, the Corporation **issued** \$160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2 (for additional details on these shares, refer to Note 13 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.

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 100% 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)			
Short term committed	300.0	32.0	268.0
Uncommitted	28.7	1.9	26.8
Total	328.7	33.9	294.8

The Corporation's short term committed lines of credit consist 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 issues of letters of credit. 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. All of these facilities are unsecured.

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	2,842.5	125.0	139.5	100.0	2,478.0
Interest expense	2,827.2	186.0	332.6	325.4	1,983.2
Operating leases	61.1	11.5	17.0	11.9	20.7
Purchase obligations:					
Alberta Power (2000) coal purchase contracts ⁽¹⁾	512.7	51.1	106.2	112.6	242.8
Capital Expenditures ⁽²⁾	83.9	83.9	-	-	-
Other	4.4	2.6	1.0	0.8	-
Total	6,331.8	460.1	596.3	550.7	4,724.7

Notes:

⁽¹⁾ 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.

⁽²⁾ Various contracts to purchase goods and services with respect to capital expenditure programs.

NET CURRENT AND LONG TERM FUTURE INCOME TAXES

Net current and long term future income taxes at December 31, 2009, were \$326.6 million, an increase of \$307.8 million (1,637%) 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, the Corporation 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 3,286,124 Class A Shares and 2,014,076 Class B Shares, all of which are owned by Canadian Utilities.

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.

In March 2009, the Corporation 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.

In addition, as at December 31, 2009, the Corporation has available committed and uncommitted lines of credit of approximately \$0.3 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.

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 \$60.0 million to \$70.0 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 100% of the costs of funding its pension plans from utility customers (refer to Segmented Information – Utilities – Regulatory Developments – Pension Hearing section). As amounts approved by the AUC may vary from the amounts requested, the Corporation may not recover all of its costs of funding from utility customers.

Alberta Power (2000) contracts the operations of its power generating plants to ATCO Power, a wholly-owned subsidiary of CU Inc.'s parent company, Canadian Utilities. As a result, ATCO Power is responsible for funding the appropriate pension contributions for these employees. Costs relating to pensions are recovered by Alberta Power (2000) under the terms of the PPAs. Due to pension accounting rules, funding contributions are not the same as pension expense amounts. For more information refer to Note 19 to 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. Alberta Power (2000)'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 \$11.9 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.

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. Alberta Power (2000) 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.

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 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.

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 20 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

Entity (\$ millions)	Relationship	Transaction	Recorded As	2009	2008
Canadian Utilities Limited	Parent	Sale of electricity and natural gas, lease of land, rent and office services	Revenues	0.1	0.4
		Rent and aircraft usage	Selling and administrative	8.9	7.9
		Purchase of equipment and leasehold improvements	Property, plant and equipment	2.9	1.9
ATCO Ltd. and ATCO Investments Ltd.	Affiliates	Corporate signature rights and rent	Selling and administrative	3.4	3.3
ASHCOR Technologies Ltd., ATCO Frontec Corp., ATCO I-Tek Inc., ATCO Midstream Ltd., ATCO Power Ltd., ATCO Energy Solutions Ltd. and ATCO Travel Ltd.	Affiliates	Natural gas storage, transportation and other gas services, sale of ash, rent and office services, payroll and accounting services	Revenues	27.7	29.0
		Purchase and storage of natural gas	Natural gas supply	2.3	4.1
		Purchase of natural gas	Operation and maintenance	6.0	10.2
		Purchase of natural gas	Regulatory assets	(13.3)	(19.2)
		Computer operations and systems development, call centre and customer billing services	Operation and maintenance, selling and administrative	86.7	80.5
		North Warning System joint venture earnings	Other income	0.4	0.3
		Purchase of equipment and capitalized costs and	Property, plant and equipment	14.3	17.1
		Capitalized software	Intangibles	28.3	24.1

The Corporation incurred advertising and promotion expenses from an entity related through common control totaling \$0.3 million (2008 – \$0.3 million).

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.

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 years 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 6 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 \$198.1 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 \$48.0 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, 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 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.

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.

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) (4)}				
	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Total
2009					
Revenues	476.1	388.0	368.9	444.3	1,677.3
Earnings attributable to Class A and Class B Shares	90.3	49.7	56.5	66.1	262.6
Adjusted Earnings ⁽⁵⁾	90.3	49.7	39.7	66.1	245.8
2008					
Revenues	443.4	363.9	352.6	413.5	1,573.4
Earnings attributable to Class A and Class B Shares	77.7	33.5	30.9	58.2	200.3
Adjusted Earnings ⁽⁵⁾	77.7	33.5	27.9	53.4	192.5

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 and the timing of rate decisions.

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

⁽⁴⁾ As all the Class A and Class B shares of the Corporation are owned by Canadian Utilities Limited, the disclosure of earnings per share is not provided as it is not considered to be meaningful.

⁽⁵⁾ Refer to Significant Non-Operating Financial Items section for a description of the adjustments made to earnings attributable to Class A and Class B Shares to obtain Adjusted Earnings.

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

- the timing of utility rate decisions;
- amount of franchise fees collected by ATCO Gas on behalf of municipalities;
- availability of power generating plants in Alberta Power (2000);
- fluctuations in temperatures;
- Carbon Facility decisions;
- Increase in rate base in the Utilities Segment;
- 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);
- H.R. Milner Income Tax Reassessment;
- Other Post Employment Benefits;
- Federal Court of Appeal Decision - Mining Assets; and
- 2008 Tax Assessment.

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 ^{(1) (2) (3)}		
	2009	2008	Change to 2009 (2009-2008)
Utilities	367.9	330.4	11%
Energy	76.4	83.2	(8%)
Intersegment eliminations	-	(0.1)	100%
Revenues	444.3	413.5	7%

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 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 increased by \$30.8 million primarily due to 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). These increases were partially offset by lower Excess Energy revenue in Alberta Power (2000).

SEGMENTED EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES (\$ millions)	For the Three Months Ended December 31 ^{(1) (2) (3) (4)}		
	2009	2008	Change to 2009 (2009-2008)
Utilities	52.8	45.3	17%
Energy	13.2	12.7	4%
Corporate & Other	0.1	0.2	(50%)
Earnings attributable to Class A and Class B Shares	66.1	58.2	14%

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, and the timing of rate decisions.
- ⁽³⁾ The above data (other than Adjusted Earnings) has been extracted from the financial statements, which have been prepared in accordance with GAAP, and the reporting currency is the Canadian dollar.
- ⁽⁴⁾ As all the Class A and Class B shares of the Corporation are owned by Canadian Utilities Limited, the disclosure of earnings per share is not provided as it is not considered to be meaningful.

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	13.2	0.1	-	66.1
Adjusted Earnings	52.8	13.2	0.1	-	66.1
2008					
Earnings attributable to Class A and Class B Shares	45.3	12.7	0.2	-	58.2
Other Post Employment Benefits ⁽¹⁾	-	(1.5)	-	-	(1.5)
2008 Tax Assessment ⁽¹⁾	(3.3)	-	-	-	(3.3)
Adjusted Earnings	42.0	11.2	0.2	-	53.4

Notes:

⁽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 \$7.9 million (14%) over 2008, including the impact of adjustments identified in the Significant Non-Operating Financial Items section.

Fourth quarter **Adjusted Earnings increased** by \$12.7 million (24%) over 2008 primarily due to 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 higher financing costs in ATCO Electric compared to amounts included in customer rates.

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.

OTHER EXPENSES (\$ millions)	For the Three Months Ended December 31		
	2009	2008	Change to 2009 (2009-2008)
Operating expenses:			
Natural gas supply	0.3	0.5	(40%)
Purchased power	14.3	14.9	(4%)
Operation and maintenance	125.8	110.2	14%
Selling and administrative	72.4	68.4	6%
Franchise fees	43.9	42.5	3%
	256.7	236.5	9%
Depreciation and amortization expenses	61.6	76.2	(19%)
Interest	50.9	47.4	7%
Income taxes	11.7	0.5	2,240%

Fourth quarter **operating expenses increased** by \$20.2 million (9%) over 2008. Operation and maintenance expenses were higher 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). Selling and administrative expenses increased in the Utilities Segment primarily as a result of higher employment costs due to growth.

Fourth quarter **depreciation and amortization expenses decreased** by \$14.6 million (19%) 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 \$3.5 million (7%) 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.

Income taxes in the fourth quarter **increased** by \$11.2 million (2,240%) 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)	2009	2008	Change to 2009 (2009-2008)
Cash position, beginning of period	267.1	177.1	51%
Cash provided by (used in):			
Operating activities:			
Funds Generated by Operations	148.8	165.7	(10%)
Changes in non-cash working capital	(25.9)	(53.0)	51%
Cash flow from operations	122.9	112.7	9%
Investing activities	(161.6)	(253.0)	(36%)
Financing activities	(164.3)	(45.8)	(259%)
Cash position, end of period	64.1	(9.0)	812%

OPERATING ACTIVITIES

Funds Generated by Operations decreased by \$16.9 million (10%) 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 **increased** by 9% primarily due to changes in non-cash working capital, partially offset by decreases in funds generated by operations.

INVESTING ACTIVITIES

Investing in the fourth quarter **decreased** by 36% 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 did not issue any long term debt. **Redemptions** were comprised of \$125.0 million of 10.20% Debentures due November 30, 2009.

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