



An **ATCO** Company

# **MANAGEMENT'S DISCUSSION AND ANALYSIS**

**FOR THE YEAR ENDED  
DECEMBER 31, 2010**

**CU Inc.**  
**Management's Discussion and Analysis (MD&A)**  
**For the Year Ended December 31, 2010**

This MD&A should be read in conjunction with the Corporation's unaudited consolidated financial statements for the three months ended December 31, 2010, and the audited consolidated financial statements for the year ended December 31, 2010. This MD&A is dated February 22, 2011. Additional information relating to the Corporation, including the Corporation's annual information form, is available on SEDAR at [www.sedar.com](http://www.sedar.com).

**Table of Contents**

	Page
Glossary .....	2
Company Overview .....	2
Transfer of Alberta Power (2000) to ATCO Power .....	3
Forward-Looking Information .....	4
Non-GAAP Measures .....	4
Controls and Procedures .....	5
Disclosure Controls and Procedures .....	5
Internal Control over Financial Reporting .....	5
Annual Results of Operations .....	6
Selected Information .....	6
Reconciliation of Earnings Attributable to Class A and Class B Shares and Adjusted Earnings .....	7
Significant Non-Operating Financial Item .....	7
Consolidated Revenues and Adjusted Earnings .....	8
Consolidated Expenses .....	8
Utilities Information .....	9
Liquidity and Capital Resources .....	15
Share Capital .....	18
Business Risks .....	18
Pension Plans .....	18
Financing .....	19
Pipeline Integrity .....	19
Carbon Natural Gas Storage Facility .....	20
Regulated Operations .....	20
Derivative Financial Instruments .....	21
Transactions with Related Parties .....	23
Off-Balance Sheet Arrangements .....	24
Contingencies .....	24
Critical Accounting Estimates .....	24
Changes in Accounting Policies .....	24
Future Accounting Changes .....	25
Quarterly Results of Operations .....	29
Selected Information .....	29
Fourth Quarter 2010 .....	30

## 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.

**Alberta Power (2000)** means Alberta Power (2000) Ltd., the wholly owned subsidiary of CU Inc. that was transferred to ATCO Power Ltd. on October 1, 2010.

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

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

**ATCO Power** means ATCO Power Ltd., a wholly owned subsidiary of Canadian Utilities.

**AUC** means the Alberta Utilities Commission.

**Canadian Utilities** means Canadian Utilities Limited.

**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.

**GAAP** means Canadian generally accepted accounting principles.

**IFRS** means International Financial Reporting Standards.

**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.

## Company Overview

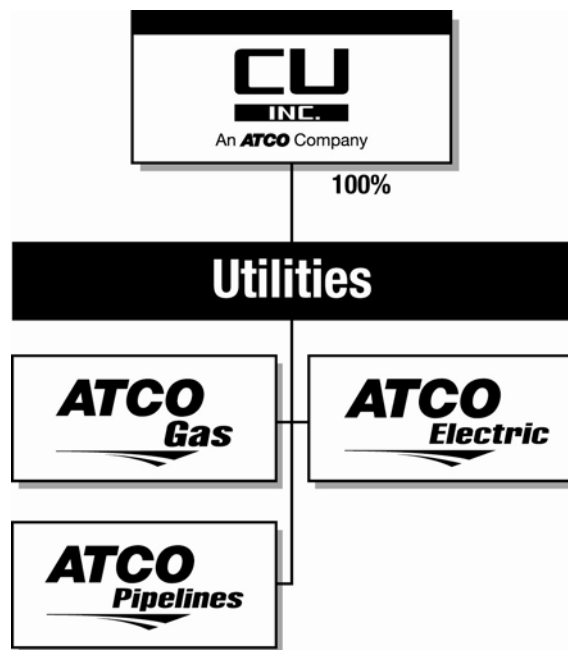
CU Inc. was incorporated under the laws of Canada on March 12, 1999. The Corporation has assets of approximately \$7 billion and more than 4,300 employees.

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 utility businesses:

- 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.

### Simplified Organizational Structure



### TRANSFER OF ALBERTA POWER (2000) TO ATCO POWER

Effective October 1, 2010, the Corporation transferred ownership of its wholly owned subsidiary, Alberta Power (2000) to ATCO Power Ltd., a wholly owned subsidiary of Canadian Utilities, the Corporation's parent. As this was a related party transaction by companies under common control, it was accounted for by the Corporation at the carrying amount. The transfer resulted in a non-cash distribution of \$249.5 million from the Corporation to its parent, Canadian Utilities. Commencing October 1, 2010, the Corporation no longer recognized Alberta Power (2000)'s financial position, results of operations and cash flows in its consolidated financial statements. The results of operations and the cash flows of Alberta Power (2000) for the periods prior to October 1, 2010, have been presented as a discontinued operation in the consolidated financial statements for the year ended December 31, 2010. These amounts were previously recognized in the Energy Segment.

ATCO Electric, ATCO Gas and ATCO Pipelines continue to be owned and financed by the Corporation. As a result of this transfer, the Corporation is comprised of rate regulated utility operations in natural gas and electricity transmission and distribution.

The results of operations for Alberta Power (2000) are presented on two line items called "Earnings from discontinued operations" and "Dividends on equity preferred shares to parent corporation from discontinued operations" in the consolidated statement of earnings. The cash flows for Alberta Power (2000) are segregated in separate discontinued operations lines in operating and investing activities in the consolidated statement of cash flows. Comparative results have been restated to reflect the impact of

operations that have been classified as discontinued during 2010. See note 4 of the Corporation's consolidated financial statements for the year ended December 31, 2010.

Alberta Power (2000)'s results for 2010 are discussed on an Adjusted Earnings basis only. Revenue and expense variance explanations relate solely to continuing operations (refer to Annual Results of Operations - Consolidated Revenues and Adjusted Earnings and Consolidated Expenses sections).

## **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 Annual 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, 2010, 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. 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 error, if any, within the Corporation have been detected.

Based on this evaluation, the CEO and the CFO have concluded that the Corporation's disclosure controls and procedures were effective at December 31, 2010.

## INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2010, 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 the Corporation's internal control over financial reporting was effective at December 31, 2010.

There was no change in the Corporation's internal control over financial reporting that occurred during the period beginning on October 1, 2010, and ended on December 31, 2010, 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		
	2010	2009	2008
(\$ millions, except per share data and return on equity) <sup>(2)(7)</sup>			
Revenues	1,476.7	1,367.4	1,260.8
Earnings attributable to Class A and Class B Shares:			
Continuing operations	245.7	195.5	148.9
Discontinued operations <sup>(1)</sup>	31.5	67.1	51.4
Total	277.2	262.6	200.3
Adjusted Earnings: <sup>(3)</sup>			
Continuing operations	245.7	195.5	143.4
Discontinued operations <sup>(1)</sup>	31.5	50.3	49.1
Total	277.2	245.8	192.5
Total assets	6,636.9	6,592.2	5,405.2
Long term debt	2,828.3	2,827.4	2,683.2
Equity preferred shares	449.4	405.0	245.0
Class A and Class B Share owner's equity	2,066.5	2,038.8	1,815.4
Return on equity (%)	13.5	13.6	11.5
Cash flow from operations:			
Continuing operations	459.2	403.6	355.9
Discontinued operations <sup>(1)</sup>	50.8	104.4	142.7
Total	510.0	508.0	498.6
Funds Generated by Operations	469.5	410.1	377.0
Capital expenditures	788.9	776.1	852.6
Cash dividends declared per share (\$):			
Series Preferred Shares:			
Series 1	1.15	1.15	1.15
Series 2 <sup>(4)</sup>	1.675	1.14	-
Series Second Preferred Shares:			
Series U <sup>(5)</sup>	1.09	1.09	1.09
Series V <sup>(6)</sup>	1.18	1.18	1.18

### Notes:

<sup>(1)</sup> Discontinued operations consist of Alberta Power (2000) which was transferred to ATCO Power, a wholly owned subsidiary of the Corporation's parent, Canadian Utilities, on October 1, 2010 (refer to Company Overview – Transfer of Alberta Power (2000) to ATCO Power section).

<sup>(2)</sup> The above data (other than Adjusted Earnings, Funds Generated by Operations and return on equity) has been extracted from the financial statements.

<sup>(3)</sup> Refer to Significant Non-Operating Financial Items section for a description of adjustments to obtain Adjusted Earnings.

<sup>(4)</sup> Series 2 Preferred Shares were issued on March 27, 2009.

<sup>(5)</sup> 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.

<sup>(6)</sup> 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.

<sup>(7)</sup> As all the Class A and Class B Shares of the Corporation are owned by Canadian Utilities, 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

**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)	Continuing Operations	Discontinued Operations	Total
<b>2010</b>			
Earnings and Adjusted Earnings attributable to Class A and Class B Shares	<b>245.7</b>	<b>31.5</b>	<b>277.2</b>
<b>2009</b>			
Earnings attributable to Class A and Class B Shares	195.5	67.1	262.6
H.R. Milner Income Tax Reassessment <sup>(1)</sup>	-	(16.8)	(16.8)
Adjusted Earnings	195.5	50.3	245.8

### SIGNIFICANT NON-OPERATING FINANCIAL ITEM

Consolidated financial results include the following significant non-operating financial item.

#### (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 was a \$13.7 million recovery of income tax and related interest expense reassessed by CRA in 2006. In addition, Alberta Power (2000) received interest income of approximately \$3.1 million earned on such amounts paid to CRA. These adjustments resulted in a \$16.8 million increase in earnings which was recorded in the third quarter of 2009. In total, Alberta Power (2000) received refunds of approximately \$28.0 million including interest and net of consequential adjustments to other taxation years arising from the judgment.

## CONSOLIDATED REVENUES AND ADJUSTED EARNINGS

**Revenues** in 2010 **increased** by \$109.3 million (8%) over 2009. This increase was primarily attributable to increased rate base in ATCO Electric and an AUC decision received on the Carbon Compliance Application, partially offset by Carbon decisions recorded in 2009 (Carbon Decisions) in ATCO Gas (refer to Utilities Information section). These increases were partially offset by the deferred gas account decision by the Alberta Court of Appeal (Deferred Gas Account Decision) in ATCO Gas.

**Adjusted Earnings from continuing operations** were \$245.7 million, an **increase** of \$50.2 million (26%) compared to 2009. This increase was mainly due to the impact of the Carbon Decisions in ATCO Gas and increased rate base in ATCO Electric, ATCO Gas and ATCO Pipelines (the Utilities), partially offset by the Deferred Gas Account Decision in ATCO Gas.

**Adjusted Earnings from discontinued operations** were \$31.5 million, a **decrease** of \$18.8 million (37%) compared to 2009. For the nine months ended September 30, 2010, Adjusted Earnings were lower than the corresponding period in 2009 due to higher maintenance expenses and lower amortization of deferred availability incentives in Alberta Power (2000). Adjusted Earnings for the fourth quarter of 2010 were nil.

**Interest and other income** in 2010 **increased** by \$5.0 million to \$52.3 million over 2009, mainly due to interest income on ATCO Gas' Carbon Compliance decision.

## CONSOLIDATED EXPENSES

(\$ millions)	For the Year Ended December 31		
	2010	2009	Change to 2010 (2010-2009)
Operating expenses:			
Natural gas supply	1.4	1.0	40%
Purchased power	54.2	54.1	0%
Operation and maintenance	339.9	315.5	8%
Selling and administrative	251.4	238.0	6%
Franchise fees	172.7	163.5	6%
	<b>819.6</b>	<b>772.1</b>	<b>6%</b>
Depreciation and amortization	211.7	192.4	10%
Interest	192.2	198.7	(3%)
Income taxes	39.0	37.9	3%
Dividends on equity preferred shares	20.8	18.1	15%

**Operating expenses** in 2010 **increased** by \$47.5 million (6%) over 2009. Operation and maintenance expenses were higher primarily due to higher line maintenance and brushing costs in ATCO Electric and pension contributions which commenced in 2010. Selling and administrative expenses were higher mainly due to increased regulatory expenses.

In 2010, **depreciation and amortization expenses increased** by \$19.3 million (10%) compared to 2009, primarily due to capital additions in 2009 and 2010.

**Interest expense** in 2010 **decreased** by \$6.5 million (3%) compared to 2009, primarily due to the redemption of \$125.0 million of 11.40% Debentures which matured on August 15, 2010. These debentures were not refinanced until the November 18, 2010, issuance of \$125.0 million of 4.947% Debentures. This decrease was partially offset by the impact of the Deferred Gas Account Decision in ATCO Gas.

In 2010, **income taxes increased** by \$1.1 million (3%) over 2009, primarily due to higher earnings before taxes. This increase was partially offset by a \$6.1 million income tax expense recorded in 2009 resulting from the removal of the Carbon Natural Gas Storage Facility from regulation in ATCO Gas and a \$4.4 million income tax adjustment due to a reclassification of certain assets for the years 2000 to 2004 in ATCO Pipelines.

**Dividends on equity preferred shares** in 2010 **increased** by \$2.7 million (15%) over 2009 as a result of the issue of \$160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2 on March 27, 2009, and \$75.0 million of 3.80% Cumulative Redeemable Preferred Shares Series 4 on December 2, 2010.

## **UTILITIES INFORMATION**

The Utilities are regulated primarily by the AUC, which administers acts and regulations covering such matters as rates, financing, accounting and service area. The 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 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.

### ***Regulatory Developments***

#### **AUC Initiative to Reform Rate Regulation**

On February 26, 2010, the AUC advised that it was beginning an initiative to reform utility rate regulation in Alberta. The intent of this initiative is to move to a form of rate regulation referred to as “performance based regulation” in which prevailing rates are adjusted annually by a formula that recognizes inflation and productivity improvements. The rate regulation initiative will begin with the reform of rate regulation for electricity and natural gas distribution services. The reform of rate regulation for electricity and natural gas transmission is excluded from this initiative at this time.

The AUC has advised that the target date for the implementation of performance based regulation for ATCO Gas and ATCO Electric will be January 1, 2013, based on applications to be filed in the second quarter of 2011. The impact of this initiative on ATCO Gas’ and ATCO Electric’s distribution operations cannot be determined at this time.

## **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. 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. On December 16, 2010, the AUC initiated a 2011 Generic Cost of Capital proceeding, the scope of which includes, among other things, a full review of cost of capital matters including capital structure and the ROE for 2011. It will also include consideration of whether a formula approach to ROE can be reinstated for 2012. In the absence of a formula approach to ROE, the AUC will then consider how the ROE will be set for 2012. The scope also includes consideration of a management fee on customer contributed assets and how such a fee would be accounted for. The proceeding is scheduled to be completed in the third quarter of 2011 and a decision is expected in the fourth quarter of 2011.

## **Pension Hearing**

In July 2009, the Utilities submitted an application to the AUC requesting recovery of the expected 2010 contributions to the Canadian Utilities pension plan. Prior to 2010, there had been no required contributions since 1996. The Utilities also requested the establishment of deferral accounts due to projected funding requirements and the potential for fluctuations in pension asset values and resulting funding requirements. A hearing was held in January 2010 and an AUC decision was issued on April 30, 2010, approving the requested funding and establishing deferral accounts for funding fluctuations beyond the control of the Utilities. This decision did not result in a material change in the Utilities' earnings.

On December 15, 2010, the Utilities submitted an application supporting the pension methodology, specifically the determination of the cost of living allowance provision, used in the determination of pension costs included in the 2011 and future years' revenue requirements of the Utilities. The AUC expanded the scope of the application so that it will also be the basis to determine the 2011/2012 pension cost recovery for the Utilities. The application is as a result of a directive issued by the AUC in the pension decision issued on April 30, 2010. A decision is expected in the fourth quarter of 2011.

## **Benchmarking**

The Utilities 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. An AUC decision was issued on March 8, 2010, which addressed the 2003-2007 Placeholder amounts for the Utilities. The AUC decision approved the adjustments to the Placeholder amounts as filed based on fair market value resulting in no material changes to earnings.

For the 2008 and 2009 period, a separate regulatory process has been established 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 proceeding is scheduled to be completed in the first quarter of 2011 and a decision is expected in the second quarter of 2011.

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 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.

### **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. As of December 31, 2010, this proceeding remains suspended.

### **ATCO Electric**

#### **2011 and 2012 General Tariff Application**

In May 2010, ATCO Electric filed a general tariff application with the AUC for 2011 and 2012 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. The application also requested that construction work in progress for projects that are directly assigned from the AESO be included in rate base. Further, ATCO Electric is also seeking recovery of Federal future income taxes in customer rates for its transmission operations. These requests would not impact earnings but would improve cash flow during the construction of the major transmission projects currently being undertaken. A decision is expected in the second quarter of 2011.

#### **2009 and 2010 General Tariff Application**

On July 2, 2009, the AUC issued a decision on ATCO Electric's 2009 and 2010 general tariff application approving, among other things, increased revenues to recover increased financing, depreciation and operating costs associated with increased rate base in Alberta. The impact of increased rate base for the year ended December 31, 2010, increased ATCO Electric's revenues and earnings by approximately \$75 million and \$13 million, respectively, compared to 2009.

## **Transmission Infrastructure Projects**

### **Northwest Alberta Transmission Projects**

In August 2006, the AUC approved the AESO application for increased transmission infrastructure in northwest Alberta. The work includes four distinct transmission line projects and will result in approximately 700 kilometres of new transmission lines to be constructed by 2012.

All four transmission line projects have been assigned to ATCO Electric by the AESO and final approval has been received from the AUC for these projects with an estimated cost of \$415.0 million and completion estimated by the end of the second quarter of 2012. ATCO Electric has completed construction of two of the transmission lines totaling 480 kilometres and is currently constructing the two other transmission lines totaling approximately 220 kilometres.

In addition to the four transmission line projects, there are several additional infrastructure projects in northwest Alberta with an estimated cost of approximately \$75 million which are anticipated to be complete by the end of 2012. ATCO Electric estimates the total cost of the northwest Alberta projects to be approximately \$490 million, \$385 million of which has been incurred and included in the financial statements for the year ended December 31, 2010.

### **AESO Long-Term Transmission System Plan**

In June 2009, the AESO released its long-term transmission system plan. 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 directly assign projects, utilize service territory assignments or put future critical transmission infrastructure projects out for competitive bid.

Pursuant to the amended legislation, the AESO is in the process of developing a recommended model for the competitive procurement process for critical transmission infrastructure. Competitive procurement refers to the provision of specific transmission infrastructure via a process that enables all deemed qualified bidders to compete in a fair, transparent and open environment for the right to build, own and operate or transfer the identified transmission infrastructure to an existing Transmission Facility Owner. The AESO expects to issue a draft recommended process by the end of the first quarter of 2011. The AESO will then develop a competitive procurement process document to file with the AUC, currently anticipated for the third quarter of 2011, for its approval.

### **500kV High Voltage Direct Current (“HVDC”) Project**

In 2009, ATCO Electric was authorized by the Alberta Minister of Energy to prepare a facility application to build and operate a new 500kV HVDC transmission line along a corridor on the east side of the province between Edmonton and Calgary. Following approval of the facility application by the AUC, ATCO Electric will construct and operate the new line. In December 2010, ATCO Electric filed its proposal for the project with the AESO at an estimated cost, excluding capitalized interest during construction, of \$1.6 billion with an in-service date of December 31, 2013. In February 2011, the AESO revised the required in-service date to mid to late 2014 and directed ATCO Electric to review and update its original proposal for the project incorporating the new in-service date and any revisions to the estimated cost. Once ATCO Electric files and the AESO accepts the revised project proposal, ATCO Electric expects to complete and file the facility application with the AUC in the first quarter of 2011.

seeking final approval to construct and operate the facility. Final approval is not anticipated until late 2011. Approval of the facility application is required before construction commences. It is anticipated that the majority of the project costs will be incurred in 2012 through 2014.

### **Hanna Region Transmission Development (“HRTD”) Project**

On April 29, 2010, the AUC approved the need for major transmission reinforcement in the Hanna area located in the southeast region of the province. ATCO Electric’s share of the Hanna Region Transmission Development or “HRTD”, is comprised of six distinct developments comprising approximately 375 kilometres of transmission line projects, the construction of seven new substations and modifications and expansions to a further 13 existing substations. The in-service dates for the majority of these six developments are anticipated to be in late 2012 with an estimated cost for the HRTD of approximately \$800 million. ATCO Electric expects to file the remainder of the facility applications with the AUC by the end of the first quarter of 2011, final approvals for which are not anticipated until the fourth quarter of 2011. It is anticipated that the majority of these costs will be incurred in 2011 and 2012.

In addition to the increased transmission infrastructure in northwest Alberta and the HVDC and HRTD projects, 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**

#### **2011 and 2012 General Rate Application**

In December 2010, ATCO Gas filed a general rate application with the AUC for 2011 and 2012 requesting, among other things, increased revenues to recover increased financing, depreciation, and operating costs associated with increased rate base in Alberta. A decision is expected in the fourth quarter of 2011. ATCO Gas also filed an application requesting interim adjustable rates pending the AUC’s decision on the general rate application. A decision on the interim adjustable rates application is expected in the first quarter of 2011.

#### **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.

Through its Carbon Compliance application, ATCO Gas sought to recover total revenues from customers of \$45.5 million, excluding interest, which would increase ATCO Gas’ earnings by a total of \$32.7 million. On October 19, 2010, the AUC released the Carbon Compliance decision, approving a recovery from customers of \$43.7 million plus interest in the amount of \$5.9 million to September 30, 2010. Through numerous regulatory processes, ATCO Gas has previously recorded revenues and earnings of \$13.8 million and \$9.9 million, respectively, in 2009. Additionally, on April 20, 2010, ATCO Gas received a decision from the AUC approving, on an interim adjustable basis, the implementation of Carbon recovery riders resulting in an increase in ATCO Gas’ revenues and earnings of \$15.7 million and \$11.3 million, respectively. As a result, in the third quarter of 2010, ATCO Gas recognized the remaining

amounts pertaining to the Carbon Compliance application and related decision issued by the AUC resulting in an increase in ATCO Gas' revenues, interest income and earnings of \$14.2 million, \$5.9 million, and \$14.5 million, respectively.

ATCO Gas filed an application with the AUC on December 1, 2010, to approve the internal transfer of the Carbon facility from ATCO Gas to ATCO Midstream. The transaction is subject to the completion of documentation and receipt of all necessary approvals, including regulatory approval in a form satisfactory to the Board of Directors of Canadian Utilities. The transaction is expected to be completed in the second quarter of 2011.

### **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 a 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.

The City of Calgary's appeal with respect to this decision was heard by the Alberta Court of Appeal on January 13, 2010. On April 23, 2010, the Alberta Court of Appeal issued a decision allowing the appeal and vacating orders under appeal and returned the matter to the AUC for consideration. The AUC completed a process to address the Alberta Court of Appeal decision and on October 15, 2010, issued a decision requiring ATCO Gas to refund to customers approximately 85% of the transportation imbalance adjustment amounts in question resulting in a refund of approximately \$9.7 million, including interest of \$1.7 million, and a decrease in ATCO Gas' 2010 earnings of \$7.1 million.

### **2005, 2006, and 2009 General Rate Application**

In May 2006, the City of Calgary filed a review and variance application with the AUC, alleging that the AUC made errors in ATCO Gas' 2005-2007 general rate application decision related to the calculation of working capital needed by ATCO Gas to operate the Carbon Facility. The AUC issued a decision on January 17, 2007, denying the City of Calgary's application. On February 15, 2007, the City of Calgary filed for a Leave to Appeal this decision with the Alberta Court of Appeal. On June 19, 2007, the appeal was heard with the Court granting the City of Calgary leave to appeal on August 3, 2007. A hearing was held on March 11, 2010, and a decision dismissing the appeal was issued by the Alberta Court of Appeal on March 24, 2010.

## **ATCO Pipelines**

### **Alberta System Integration**

In 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.

In 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), and filed a second application

with the AUC to approve its 2010, 2011 and 2012 negotiated settlement, which was a condition precedent of the Integration Application.

The AUC issued a decision on May 27, 2010, approving integration and the 2010, 2011 and 2012 negotiated settlement but requested ATCO Pipelines to submit subsequent applications to address the specific details on: (i) the transition of ATCO Pipelines' customers to NOVA, and (ii) the asset swap between ATCO Pipelines and NOVA in order to establish operating areas. ATCO Pipelines has submitted an application to the AUC to address the transition of customers and a decision is expected in the second quarter of 2011. An application to address the asset swap will be submitted to the AUC in the first quarter of 2011.

### 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.

## 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		
	2010	2009	Change to 2010 (2010-2009)
<b>Cash position, beginning of period</b>	<b>64.1</b>	(9.0)	812%
Cash provided by (used in)			
Operating activities:			
Funds Generated by Operations	<b>469.5</b>	410.1	14%
Changes in non-cash working capital	<b>(10.3)</b>	(6.5)	(58%)
Cash flow from continuing operations	<b>459.2</b>	403.6	14%
Cash flow from discontinued operations	<b>50.8</b>	104.4	(51%)
Cash flow from operations	<b>510.0</b>	508.0	0%
Investing activities	<b>(701.2)</b>	(695.0)	(1%)
Financing activities	<b>71.6</b>	260.1	(72%)
<b>Cash position, end of period</b>	<b>(55.5)</b>	64.1	(187%)

### OPERATING ACTIVITIES

**Funds Generated by Operations** were \$469.5 million in 2010, an **increase** of \$59.4 million (15%) over 2009. This increase was primarily due to higher earnings in the Utilities. Cash flow from discontinued operations relates to Alberta Power (2000) and is lower than 2009 due to the receipt of amounts owing to Alberta Power (2000) in 2009 as a result of the H.R. Milner Income Tax Reassessment.

## INVESTING ACTIVITIES

**Cash used in investing activities** was essentially **unchanged** at \$701.2 million in 2010 compared to \$695.0 million in 2009. **Capital expenditures** in 2010 **increased** by \$12.8 million to \$778.9 million. This increase was primarily due to increased investment in regulated natural gas distribution projects in ATCO Gas, partially offset by decreased investment in regulated transmission and distribution projects in ATCO Electric.

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately \$1.3 billion in 2011, an increase of \$0.5 billion over 2010. For the 2011 to 2013 period, capital expenditures are expected to be approximately \$5.0 billion to \$6.0 billion (refer to Utilities Information – Regulatory Developments – ATCO Electric – Transmission Infrastructure Projects section). These expenditures are expected to be financed by a combination of funds generated by operations, equity investments from the Corporation’s parent, Canadian Utilities, and capital market financings.

The planned capital expenditures are based on the following significant assumptions:

- the projects identified by the AESO will proceed as currently scheduled;
- the remaining planned capital expenditures are required to maintain safe and reliable 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;
- the regulatory system in Alberta will remain substantially unchanged; and
- continued access to capital market financings.

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

The Utilities 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.

The Corporation is subject to the normal risks associated with major capital projects, including delays and cost overruns. Although the Corporation attempts to mitigate these risks 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 2010, **issuances** of debt of \$125.0 million of 4.947% Debentures due November 18, 2050 were offset by **redemptions** of \$125.0 million of 11.40% Debentures which matured on August 15, 2010.

On December 2, 2010, the Corporation **issued** \$75.0 million of 3.80% Cumulative Redeemable Preferred Shares Series 4. In 2009, the Corporation **issued** \$160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2.

## 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, 2010.

## LINES OF CREDIT

At December 31, 2010, 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	35.8	264.2
Uncommitted	28.7	1.6	27.1
Total	328.7	37.4	291.3

The Corporation's short term committed lines of credit consist of a \$300 million unsecured revolving extendible credit facility established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for the Corporation's commercial paper program and for issues of letters of credit. This facility will expire in July 2011, unless it is 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:

	Total	Payments Due by Period			
		Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
(\$ millions)					
Accounts payable and accrued liabilities	249.7	249.7	-	-	-
Accounts payable to parent and affiliate corporations	25.9	25.9	-	-	-
Operating leases	66.4	12.0	18.9	14.9	20.6
Long term debt	2,842.5	100.0	39.5	100.0	2,603.0
Interest expense	2,894.8	174.3	339.7	332.7	2,048.1
Purchase obligations:					
Capital expenditures <sup>(1)</sup>	86.5	86.5	-	-	-
Other	1.1	0.5	0.4	0.2	-
Total	6,166.9	648.9	398.5	447.8	4,671.7

Note:

<sup>(1)</sup> Various contracts to purchase goods and services with respect to capital expenditure programs.

## BASE SHELF PROSPECTUS

On May 18, 2010, the Corporation filed a base shelf prospectus that permits it to issue up to an aggregate of \$1,700.0 million of debentures over the twenty-five month life of the prospectus. On November 18, 2010, the Corporation issued \$125.0 million of 4.947% Debentures due November 18, 2050, leaving \$1,575.0 million remaining.

The proceeds of this issue were advanced to ATCO Electric to be used to fund capital expenditures.

## Share Capital

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

At February 18, 2011, 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

### 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. Prior to 2010, the Corporation had not made material contributions since April 1, 1996, as a result of the defined benefit plans' surplus position. In addition the Corporation had obtained regulatory approval to fund the employer's contributions to the defined contribution component of the pension plan from the defined benefit plan surplus.

Material current service and deficit funding contributions resumed in 2010. The actual funding contributions for 2010 were established based on actuarial valuations for funding purposes as of December 31, 2009. Based on these final actuarial valuations, the employer contributions relating to both the defined contribution and the defined benefit components of the plan for 2010 were approximately \$58 million. This was comprised of \$55 million from the Utilities and \$3 million from Alberta Power (2000). Contributions commenced during the first quarter of 2010. The next actuarial valuation for funding purposes is required to be completed as of December 31, 2012.

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 its utility operations in its rate applications to the AUC, thereby, with the consent of the AUC, recovering 100% of the costs of funding its pension plans from utility customers (refer to – Utilities Information section). A description of pension expense can be found in Note 19 of the Corporation's consolidated financial statements for the year ended December 31, 2010.

## **FINANCING**

The Corporation's financing risk relates to the price volatility and availability of external financing to fund the capital expenditure program and refinance existing debt maturities. Financing risk is directly influenced by market factors. As financial market conditions change, this can affect the availability of capital and also the relevant financing costs.

To address this risk, the Corporation manages its capital structure to maintain strong credit ratings which allows the Corporation continued access to the capital markets. The Corporation also maintains sufficient liquidity through committed credit facilities and short term advances from its parent corporation, Canadian Utilities, to ensure that obligations are paid when due. The Corporation's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities, and access to capital markets.

As at December 31, 2010, the Corporation had available committed and uncommitted lines of credit of approximately \$290 million which can be utilized for general corporate purposes. The Corporation also had short term advances from parent corporation outstanding of \$39.5 million.

## **PIPELINE INTEGRITY**

Recent pipeline ruptures in the U.S. have highlighted the risks associated with pipeline integrity. Although the probability of an occurrence is very low, the consequences of a failure can be extreme. ATCO Pipelines and ATCO Gas, by the nature of their businesses, have significant pipeline infrastructure that has operated safely and effectively for decades. The Corporation continues to assess the integrity of its pipeline infrastructure.

## **CARBON NATURAL GAS STORAGE FACILITY**

In the 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 protect the integrity of the Carbon Facility by either minimizing or eliminating the effects of drainage.

## **REGULATED OPERATIONS**

Regulated operations are conducted by the following subsidiaries: ATCO Electric and its subsidiaries, ATCO Gas and ATCO Pipelines.

The Utilities 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 Utilities' 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. The determination of fair rate of return on the common equity component of rate base is an earnings and cash flow risk for the Utilities and is currently the subject of the 2011 Generic Cost of Capital proceeding (refer to Annual Results of Operations – Utilities Information section).

## **Benchmarking**

The Utilities 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. An AUC decision was issued on March 8, 2010, which addressed the 2003-2007 Placeholder amounts for the Utilities. The AUC decision approved the adjustments to the Placeholder amounts as filed based on fair market value resulting in no material changes to earnings.

For the 2008 and 2009 period, a separate regulatory process has been established 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 proceeding is scheduled to be completed in the first quarter of 2011 and a decision is expected in the second quarter of 2011.

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 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**

In 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 the Utilities' 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.

## **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, 2010, 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

On October 1, 2010, the Corporation and ATCO Power, a wholly owned subsidiary of the Corporation's parent, Canadian Utilities, finalized the internal transfer of Alberta Power (2000). For a more detailed description, refer to Company Overview – Transfer of Alberta Power (2000) to ATCO Power section.

Other transactions with related parties consisted of the following:

Entity	Relationship	Transaction	Recorded As	2010	2009
Canadian Utilities Limited	Parent	Sale of electricity and natural gas, lease of land, rent and office services	Revenues	\$ 0.1	\$ 0.1
		Rent and aircraft usage	Selling and administrative	7.3	8.9
		Purchase of equipment and leasehold improvements	Property, plant and equipment	6.0	2.9
ATCO Ltd. and ATCO Investments Ltd.	Affiliates	Corporate signature rights and rent	Selling and administrative	4.1	3.4
ASHCOR Technologies Ltd., ATCO I-Tek Inc., ATCO Midstream Ltd., ATCO Power Ltd., ATCO Energy Solutions Ltd., ATCO Structures & Logistics and ATCO Travel	Affiliates	Natural gas storage, transportation and other gas services, sale of ash, rent and office services, payroll and accounting services	Revenues	25.9	25.7
			Earnings from discontinued operations	2.5	2.0
		Purchase and storage of natural gas	Natural gas supply	2.6	2.3
		Purchase of natural gas	Operation and maintenance	3.0	3.0
			Earnings from discontinued operations	(3.6)	(3.0)
		Purchase of natural gas	Regulatory assets	3.7	(13.3)
		Computer operations and systems development, call centre and customer billing services,	Operation and maintenance, selling and administrative	70.6	66.2
			Earnings from discontinued operations	(20.2)	(20.5)
		North Warning System joint venture earnings	Other income	0.3	0.4
Purchase of equipment	Property, plant and equipment	9.6	14.3		
Capitalized software	Intangibles	8.3	28.3		

The Corporation incurred \$0.3 million (2009 – \$0.3 million) in advertising and promotion expenses from an entity related through common control.

Except for the transfer of Alberta Power (2000) to ATCO Power, these transactions were in the normal course of business and under normal commercial terms, measured at the exchange amount.

## Off-Balance Sheet Arrangements

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 judgments, 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, 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.

## Changes in Accounting Policies

### Business Combinations, Consolidated Financial Statements and Non-controlling Interests

Effective January 1, 2010, the Corporation adopted the Canadian Institute of Chartered Accountants' recommendations for Business Combinations, Consolidated Financial Statements and Non-Controlling Interests.

- *Business Combinations* requires assets and liabilities acquired in a business combination, including contingent consideration and certain acquired contingencies, to be measured at their fair value at the acquisition date and require acquisition related and restructuring costs to be expensed in the period incurred.
- *Consolidated Financial Statements* establishes the requirements for the preparation of consolidated financial statements.
- *Non-controlling Interests* establishes the accounting for a non-controlling interest in the consolidated financial statements. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity and to attribute earnings and other comprehensive income to both the parent and non-controlling interest.

The adoption of these standards resulted in the recognition and presentation of discontinued operations in the consolidated financial statements.

## **FUTURE ACCOUNTING CHANGES**

### **International Financial Reporting Standards**

The Corporation will begin reporting under International Financial Reporting Standards (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 are significant differences in recognition, measurement and disclosures.

On October 1, 2010, the Canadian Accounting Standards Board issued guidance to permit, but not require, entities with rate regulated activities to defer the transition to IFRS for one year, to 2012. The Corporation has decided to adopt IFRS effective January 1, 2011, and not to take the one year deferral for the following reasons:

- Adopting IFRS allows comparability to other non-regulated entities that will be adopting IFRS in 2011.
- Comparability to other regulated entities, whether or not they choose to take the one year deferral, will be accomplished by showing the impacts of rate regulated accounting as previously permitted by Canadian GAAP as an Adjusted Earnings item in the notes to the financial statements and in the MD&A.
- The International Accounting Standards Board (IASB) has concluded that it could not resolve the matter of accounting for rate regulated activities quickly and decided to develop a proposal for consideration for its future agenda in 2011. Therefore, waiting an additional year to adopt IFRS may not result in any greater clarity with respect to rate regulated accounting.

### **IFRS Conversion Project Status**

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 completed the Assessment and Diagnostic and Design and Planning phases of its IFRS Conversion Project in 2009 and is currently completing the Implementation and Review phase. The Implementation and Review phase involves making changes to accounting policies and procedures and financial information systems and training staff on the implementation of the new standards. Financial information in accordance with IFRS was collected in 2010 to allow for comparative reporting in 2011. The Corporation has completed the necessary changes to its financial reporting computer systems.

Position papers on issue-specific accounting differences between Canadian GAAP and IFRS and the impact on financial reporting computer systems are complete and they have been discussed with the Corporation's external auditor. The IASB's work plan includes a number of the IFRS standards that have been analyzed in the position papers. The position papers will be updated to reflect any changes resulting from final standards or directives issued by the IASB.

The Corporation has completed its review of the impact of IFRS on financial covenants. This review will be updated for changes in standards. Based on the work performed to date, the Corporation believes it will be in compliance with its financial covenants using IFRS financial information.

The Corporation has evaluated the impact of IFRS on internal control over financial reporting (ICFR) and disclosure controls and procedures (DC&P). The Corporation has not identified any changes that would individually or in aggregate materially affect, or are reasonably likely to materially affect, its ICFR or DC&P.

### **Rate Regulated Accounting**

On July 23, 2009, the IASB issued an exposure draft on rate regulated activities (the Exposure Draft). Subsequently, the IASB staff issued a summary of their analysis of the responses to the Exposure Draft. The IASB discussed various IASB staff papers in July 2010 and again in September 2010, but did not reach a conclusion on the recognition of assets and liabilities subject to rate regulation. The IASB has indicated that it will evaluate future steps for the rate regulated activities project following the public consultation on its future agenda.

In the absence of a rate regulated activities standard, the Corporation will not recognize regulatory assets and liabilities. As a result, there will be a reduction to assets of approximately \$495 million, a reduction to liabilities of approximately \$500 million and a reduction to equity of approximately \$5 million on transition to IFRS.

The absence of the recognition of regulatory deferral accounts will result in increased volatility in earnings. The Corporation is unable to predict the amount of the change because that will depend upon the nature of the decisions received from the AUC. The Corporation will disclose the impacts of rate regulation, as previously prepared under Canadian GAAP, as an Adjusted Earnings item in the notes to the financial statements and in the MD&A. It is the Corporation's belief that earnings adjusted for rate regulated accounting is a better reflection of the economics of rate regulation. In addition, this presentation will provide comparability to the Corporation's peer companies that have taken the one year deferral permitted by the Canadian Accounting Standards Board.

### **IFRS 1 Exemptions**

IFRS 1 First-time Adoption of International Financial Reporting Standards ("IFRS 1") requires entities to prepare and present an opening balance sheet at the date of transition to IFRS. The transition date for the Corporation is January 1, 2010. The Corporation has evaluated the optional exemptions available under IFRS 1 and made determinations.

In general, IFRS requires an entity to comply with all of the accounting standards effective at the end of the first reporting period after adopting IFRS. This means restating accounting transactions as if the standards had been in place when the transactions occurred. The IFRS 1 exemptions give limited exemptions from retroactively applying the standards where the cost of complying with this requirement would be likely to exceed the benefits to users of financial statements. Significant exemptions for the Corporation are:

Description of IFRS 1 Exemption	Project Status
<p data-bbox="186 296 748 327"><i>Rate Regulated Property, Plant and Equipment</i></p> <p data-bbox="186 363 813 491">An entity that is subject to rate regulation may elect to use the carrying amount of property, plant and equipment determined under previous GAAP as initial cost on transition to IFRS.</p>	<p data-bbox="836 363 1385 596">The Corporation will adopt this exemption, with the result that, except for the reclassification of customer contributions to other liabilities (see Financial Statement Reclassifications below), there will be no change in the Utilities' transitional balances for property, plant and equipment.</p> <p data-bbox="836 632 1385 894">The Corporation will not adopt this exemption for the regulated generating plants of Alberta Power (2000) which will result in a reduction of approximately \$100 million to property, plant and equipment, approximately \$25 million to deferred income tax liability and approximately \$75 million to retained earnings on transition to IFRS.</p>

### Financial Statement Reclassifications

There are a number of reclassifications that will be required under IFRS. Significant reclassifications for the Corporation are:

#### *Customer Contributions:*

The Corporation obtains contributions from utility customers to construct assets in situations where it is not economic to provide service to those customers at the approved rate charged to other customers. Under Canadian GAAP, the contributions are deducted from property, plant and equipment and amortized over the life of the related asset. Under IFRS, this contribution will 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. The transition to IFRS will result in an increase to assets and liabilities of approximately \$880 million as unamortized customer contributions are reclassified from an offset to property, plant and equipment to other liabilities on the consolidated balance sheet.

#### *Long Term Debt Due Within One Year:*

Under Canadian GAAP, when the Corporation intended to refinance long term debt within one year on a long term basis and there was a written undertaking from an underwriter to act on the Corporation's behalf with respect thereto, or sufficient capacity existed under long term bank loan agreements to issue commercial paper or assume bank loans, then long term debt due within one year was classified as long term. This treatment is not permitted under IFRS. The transition to IFRS will result in the reclassification of approximately \$125 million of long term debt due within one year from long term liabilities to current liabilities.

*Provisions:*

Under IFRS, provisions must be separately disclosed on the consolidated balance sheet. The transition to IFRS will result in the reclassification of approximately \$85 million from deferred credits to provisions.

*Nature vs. Function Presentation of the Statement of Earnings:*

IFRS requires expenses on the statement of earnings to be classified either by nature or function, whereas Canadian GAAP allows a combination of the two. The Corporation has chosen to classify expenses on the statement of earnings according to their nature as salaries, wages and benefits, energy transmission and transportation, plant and equipment maintenance, fuel costs, manufacturing raw materials and consumables used and other expenses. The classifications operation and maintenance and selling and administration will no longer appear on the statement of earnings.

# Quarterly Results of Operations

## SELECTED INFORMATION

(\$ millions except per share data)	For the Three Months Ended <sup>(2) (3) (4)</sup>				
	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Total
<b>2010</b>					
Revenues	419.3	326.0	319.4	412.0	1,476.7
Earnings attributable to Class A and Class B					
Shares:					
Continuing Operations	96.8	32.9	43.4	72.6	245.7
Discontinued Operations <sup>(1)</sup>	10.2	8.8	12.5	-	31.5
Total	107.0	41.7	55.9	72.6	277.2
Adjusted Earnings <sup>(5)</sup>					
Continuing Operations	96.8	32.9	43.4	72.6	245.7
Discontinued Operations <sup>(1)</sup>	10.2	8.8	12.5	-	31.5
Total	107.0	41.7	55.9	72.6	277.2
<b>2009</b>					
Revenues	397.1	312.0	290.4	367.9	1,367.4
Earnings attributable to Class A and Class B					
Shares:					
Continuing Operations	80.4	38.9	23.3	52.9	195.5
Discontinued Operations <sup>(1)</sup>	9.9	10.8	33.2	13.2	67.1
Total	90.3	49.7	56.5	66.1	262.6
Adjusted Earnings <sup>(5)</sup>					
Continuing Operations	80.4	38.9	23.3	52.9	195.5
Discontinued Operations <sup>(1)</sup>	9.9	10.8	16.4	13.2	50.3
Total	90.3	49.7	39.7	66.1	245.8

### Notes:

<sup>(1)</sup> Discontinued operations consist of Alberta Power (2000) which was transferred to ATCO Power, a wholly owned subsidiary of the Corporation's parent, Canadian Utilities, on October 1, 2010 (refer to Company Overview – Transfer of Alberta Power (2000) to ATCO Power section).

<sup>(2)</sup> 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.

<sup>(3)</sup> The above data (other than Adjusted Earnings) has been extracted from the financial statements.

<sup>(4)</sup> As all the Class A and Class B Shares are owned by Canadian Utilities, the disclosure of earnings per share is not provided as it is not considered to be meaningful.

<sup>(5)</sup> 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;
- the amount of franchise fees collected by ATCO Gas on behalf of municipalities;
- the availability of power generating plants in Alberta Power (2000);
- the Carbon Facility decisions;

- increase in rate base in the Utilities;
- the H.R. Milner Income Tax Reassessment;
- the transfer of Alberta Power (2000) Ltd. to ATCO Power Ltd. on October 1, 2010.

## Fourth Quarter 2010

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

### SEGMENTED INFORMATION

(\$ millions)	For the Three Months Ended December 31		
	Continuing Operations	Discontinued Operations	Total
<b>2010</b>			
Revenues	<b>412.0</b>	-	<b>412.0</b>
Earnings and Adjusted Earnings attributable to Class A and Class B Shares	<b>72.6</b>	-	<b>72.6</b>
<b>2009</b>			
Revenues	367.9	76.4	444.3
Earnings and Adjusted Earnings attributable to Class A and Class B Shares	52.9	13.2	66.1

Fourth quarter **Adjusted Earnings from continuing operations increased** by \$19.7 million (37%) over 2009 primarily due to increased rate base in the Utilities and higher tax deductible costs associated with the capital program in ATCO Electric.

Fourth quarter **Adjusted Earnings from discontinued operations** relate to Alberta Power (2000)'s operations for the three months ended December 31, 2009.

### OTHER EXPENSES

(\$ millions)	For the Three Months Ended December 31		
	2010	2009	Change to 2010 (2010-2009)
Operating expenses:			
Natural gas supply	<b>0.3</b>	0.3	0%
Purchased power	<b>14.7</b>	14.3	3%
Operation and maintenance	<b>96.7</b>	92.0	5%
Selling and administrative	<b>74.5</b>	64.9	15%
Franchise fees	<b>46.8</b>	43.9	7%
	<b>233.0</b>	215.4	8%
Depreciation and amortization expenses	<b>54.3</b>	48.3	12%
Interest	<b>45.3</b>	50.2	(10%)
Income taxes	<b>11.6</b>	9.9	17%

Fourth quarter **operating expenses increased** by \$17.6 million (8%) over 2009. Operation and maintenance expenses were higher primarily due to higher line maintenance and brushing costs in ATCO Electric and pension contributions which commenced in 2010. Selling and administrative expenses were higher mainly due to increased regulatory expenses and pension contributions.

Fourth quarter **depreciation and amortization expenses increased** by \$6.0 million (12%) compared to 2009, primarily due to capital additions in 2010.

**Interest expense** for the fourth quarter **decreased** by \$4.9 million (10%) compared to 2009, primarily due to redemption of \$125.0 million of 11.40% debentures on August 15, 2010. These debentures were not refinanced until the November 18, 2010, issuance of \$125.0 million of 4.947% debentures.

## LIQUIDITY AND CAPITAL RESOURCES

### SUMMARY OF CASH FLOW

For the Three Months Ended  
December 31

(\$ millions)			Change to
	2010	2009	2010 (2010-2009)
<b>Cash position, beginning of period</b>	<b>(163.1)</b>	267.1	(161%)
Cash provided by (used in):			
Operating activities:			
Funds Generated by Operations	<b>103.5</b>	120.8	(14%)
Changes in non-cash working capital	<b>10.2</b>	(50.0)	120%
Cash flow from continuing operations	<b>113.7</b>	70.8	61%
Cash flow from discontinued operations	-	52.1	(100%)
Cash flow from operations	<b>113.7</b>	122.9	(7%)
Investing activities	<b>(202.9)</b>	(161.6)	(26%)
Financing activities	<b>196.8</b>	(164.3)	220%
<b>Cash position, end of period</b>	<b>(55.5)</b>	64.1	(187%)

### OPERATING ACTIVITIES

**Funds Generated by Operations decreased** by \$17.3 million (14%) compared to 2009, primarily due to decreases in non-current regulatory assets and liabilities which vary from quarter to quarter and are, therefore, not comparable or indicative of funds generated by operations on an annual basis, partially offset by higher earnings. For the three months ended December 31, 2010, **changes in non-cash working capital** was \$10.2 million, an **increase** of \$60.2 million (120%) over 2009. This increase was primarily due to increased accounts payable in ATCO Electric due to higher payments to customers for the settlement of one time regulatory items in 2009.

### INVESTING ACTIVITIES

**Cash used in investing activities** in the fourth quarter **increased** by 26% over 2009, primarily as a result of higher capital expenditures on regulated transmission and distribution projects in ATCO Electric and changes in non-cash working capital due to increased payments to ATCO Electric's capital program suppliers, partially offset by the removal of bank indebtedness resulting from the transfer of Alberta Power (2000).

## FINANCING ACTIVITIES

In the fourth quarter, the Corporation **issued** \$125.0 million of 4.947% Debentures due November 18, 2050. There were no **redemptions** of long term debt in the fourth quarter.

In the fourth quarter, the Corporation **issued** \$75.0 million of 3.80% Cumulative Redeemable Preferred Shares Series 4.