

FOR THE THREE MONTHS ENDED MARCH 31, 2011

TO THE SHARE OWNERS:

Canadian Utilities reported earnings attributable to Class A and Class B shares of \$176 million (\$1.34 per share) and Adjusted Earnings of \$166 million (\$1.30 per share) for the first three months of 2011. This compares to earnings of \$150 million (\$1.14 per share) and Adjusted Earnings of \$154 million (\$1.22 per share) for the same period in 2010, an increase of \$12 million in Adjusted Earnings. For the first time, earnings reflect Canadian Utilities' implementation of International Financial Reporting Standards (IFRS). Comparative figures for 2010 have been presented on the same basis.

In 2011, Adjusted Earnings increased in the Energy Segment due to higher power pool prices and related spark spreads for ATCO Power's Alberta generating plants and in the Utilities Segment due to higher infrastructure investment in the regulated rate base. These increases were partially offset in the Energy Segment by lower prices for natural gas storage.

Adjusted Earnings is a key measure used to assess segment performance, to reflect the economics of rate regulation and to facilitate comparability of Canadian Utilities' earnings with other Canadian rate regulated companies. The importance of Adjusted Earnings is further explained after the Financial Summary and Reconciliation of Adjusted Earnings section.

RECENT DEVELOPMENTS

- Canadian Utilities established a new company – ATCO Australia Pty Ltd., a strategic initiative to capture the substantial resource sector growth in Australia. Based in Perth, ATCO Australia will provide a full range of energy and infrastructure services and is led by Managing Director & Chief Operating Officer, Steven J. Landry. Mr. Landry joined ATCO following a 27-year career in the global automotive industry. He has served as a Director for ATCO Structures & Logistics and brings extensive experience in leading management teams.
- Canadian Utilities Limited declared a first quarter dividend for 2011 of 40.25 cents per Class A non-voting and Class B common share, a 6.6% increase over the 37.75 cents paid in each of the previous four quarters. Dividends per share have increased for the 39th consecutive year.
- ATCO Electric received a decision from the Alberta Utilities Commission in regard to its 2011 and 2012 rate application. Amongst other things, the decision approved the inclusion of construction work in progress for major transmission projects in rate base and the recovery from customers of Federal deferred income taxes related to transmission operations, both of which will result in higher cash flows at a time when Canadian Utilities is undertaking significant capital expenditures.
- ATCO Gas has begun automating its meter reading system. Approximately one million meters will be converted over a four year period.
- On January 1, 2011, ATCO Ltd. and Canadian Utilities Limited completed the transfer of ATCO Ltd.'s wholly-owned subsidiary, ATCO Resources Ltd., from ATCO Ltd. to ATCO Power Ltd., a wholly-owned subsidiary of Canadian Utilities Limited for Class A non-voting and Class B common shares of Canadian Utilities Limited.

FINANCIAL SUMMARY AND RECONCILIATION OF ADJUSTED EARNINGS

A financial summary and reconciliation of Adjusted Earnings to earnings attributable to Class A and Class B shares is provided below:

(\$ Millions except per share data)	For the Three Months Ended March 31	
	2011	2010
	<i>(Unaudited)</i>	
Adjusted Earnings ⁽¹⁾	166	154
Adjustments for Rate Regulated Activities	4	(9)
Dividends on Equity Preferred Shares	6	5
Earnings Attributable to Class A and Class B Shares	176	150
Adjusted Earnings Per Share ⁽¹⁾	1.30	1.22
Earnings Per Share	1.34	1.14
Revenues	809	759
Funds Generated By Operations ⁽¹⁾⁽²⁾	402	310

⁽¹⁾ These measures are not defined by Generally Accepted Accounting Principles and may not be comparable to similar measures used by other companies.

⁽²⁾ This measure is cash flow from operations before changes in non-cash working capital.

The increase in **Revenues** is primarily due to higher flow through natural gas sales in ATCO Midstream and higher Alberta power pool prices in ATCO Power, partially offset by expiry of the Barking generating plant's revenue contract in the third quarter of 2010. In addition, the first quarter of 2010 included one-time revenues of \$65 million related to the lease of the first unit of the Karratha plant in Australia.

The increase in **Funds Generated by Operations** is primarily due to higher cash earnings and increased availability incentive receipts in ATCO Power.

IMPORTANCE OF ADJUSTED EARNINGS

Adjusted Earnings are defined as earnings attributable to Class A and Class B shares after adjusting for the timing of revenues and expenses associated with rate regulated activities and equity preferred share dividends. Adjusted Earnings will present earnings on the same basis as was used prior to adopting IFRS – that basis being the U.S. accounting principles for rate regulated entities commonly used by regulated companies in Canada. Adjusted Earnings also exclude one-time gains and losses and items that are not in the normal course of business or day-to-day operations.

Adjusted Earnings is a key measure for several reasons:

- It is used by the ATCO Group in assessing segment performance and allocating resources.
- It is the ATCO Group's view that this measure is a better reflection of the economics of rate regulation that are directly affected by orders and decisions of utility regulators.
- It will facilitate comparison with those Canadian regulated companies that choose to wait another year before adopting IFRS and with those companies that may choose to adopt U.S. accounting principles instead of IFRS.

For rate regulated activities, the differences between Adjusted Earnings and earnings as reported under IFRS are strictly timing in nature: Adjusted Earnings for the Utilities Segment are recognized on the basis of accounting principles that recognize the economics of rate regulation and take into account the orders and decisions of the regulator, whereas earnings under IFRS are recognized when billed to customers. Over time, there is no difference.

Refer to note 4 to the consolidated financial statements for descriptions of the adjustments for rate regulated activities and the timing of their recovery from or refund to customers.

Canadian Utilities' consolidated financial statements and management's discussion and analysis for the three months ended March 31, 2011, will be available on Canadian Utilities' website (www.canadian-utilities.com) or via SEDAR (www.sedar.com) or can be requested from the Company.

Alberta-based Canadian Utilities Limited, an ATCO company, with more than 5,700 employees and assets of approximately \$10 billion, delivers service excellence and innovative business solutions worldwide with leading companies engaged in Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation, natural gas gathering, processing, storage and liquids extraction) and Technologies (business systems solutions). More information can be found at www.canadian-utilities.com.



N.C. Southern
President & Chief Executive Officer
Deputy Chair



R.D. Southern
Chairman of the Board

CANADIAN UTILITIES LIMITED
Management's Discussion and Analysis (MD&A)
For the Three Months Ended March 31, 2011

This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements for the three months ended March 31, 2011 (2011 Interim Financial Statements), and the audited consolidated financial statements and unaudited MD&A for the year ended December 31, 2010 (2010 MD&A). **Information contained in the 2010 MD&A that is not discussed in this document remains substantially unchanged.** This MD&A is dated April 28, 2011. Additional information relating to the Corporation, including the Corporation's annual information form, is available on SEDAR at www.sedar.com.

Terms used throughout this MD&A are defined in the Glossary located at the end of the document.

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First Quarter Highlights

The following significant events occurred during the quarter ended March 31, 2011. These events are discussed in more detail throughout this MD&A:

- Adjusted Earnings for the quarter ended March 31, 2011 were \$166 million compared to \$154 million in the corresponding period in 2010, an increase of \$12 million (8%);
- Adjusted Earnings per share for the quarter ended March 31, 2011 were \$1.30 compared to \$1.22 in the corresponding period in 2010;
- The higher Adjusted Earnings were driven primarily by higher Alberta power pool prices in ATCO Power, partially offset by lower Adjusted Earnings from ATCO Power's U.K. Barking generating plant;
- ATCO Electric filed its facility application for the 500kV high voltage direct current project with the AUC;
- ATCO Electric received a decision from the AUC on its 2011 and 2012 general tariff application approving increased revenues to recover increased financing, depreciation, and operating costs. In addition, approval was received for construction work in progress relating to AESO direct assigned projects to be included in rate base and Federal deferred income taxes relating to transmission operations to be included in customer rates;
- ATCO Gas received approval from the AUC to transfer the Carbon natural gas storage facility (Carbon Facility) from ATCO Gas to ATCO Midstream;
- The Corporation created a new segment, ATCO Australia, to report the results of its current and future energy, power generation and infrastructure business in Australia; and
- The Corporation adopted International Financial Reporting Standards (IFRS).

Company Overview

Alberta-based Canadian Utilities Limited, an ATCO Company, with more than 5,700 employees and assets of approximately \$10 billion, delivers service excellence and innovative business solutions worldwide with leading companies engaged in Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation, natural gas gathering, processing, storage and liquids extraction), and Technologies (business systems solutions).

The consolidated financial statements include the accounts of Canadian Utilities Limited and all of its subsidiaries. The 2011 Interim Financial Statements have been prepared in accordance with International Accounting Standard 34 *Interim Financial Reporting* using policies consistent with IFRS as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC). The reporting currency is the Canadian dollar.

Internal Transfer of Subsidiary

On January 1, 2011, ATCO Ltd., the Corporation's parent, transferred its wholly owned subsidiary, ATCO Resources, to ATCO Power, a wholly owned subsidiary of the Corporation. The fair value of the common shares of ATCO Resources, net of its existing debt obligations, was \$82.5 million, as estimated by an independent financial advisor and supported by management.

ATCO Ltd. transferred its common shares of ATCO Resources to the Corporation in exchange for 1,059,658 Class A Shares and 489,171 Class B Shares of the Corporation, having a value of \$82.5 million. This is a related party transaction between entities under common control and was measured at the carrying amount.

Segments

Starting in the first quarter of 2011, the results of operations and financial position of the Corporation's energy, power generation and infrastructure business in Australia are reported in a separate segment called ATCO Australia. This new segment includes the Corporation's interests in three existing power generation plants located in Australia, which were previously reported in the Energy segment. Comparative figures for the Energy segment have been restated to conform to the current presentation.

The Corporation operates in the following business segments.

The **Utilities** segment includes:

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

The **Energy** segment includes:

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

The **ATCO Australia** segment includes:

- the non-regulated supply of electricity and cogeneration steam by ATCO Australia.

The **Corporate & Other** segment includes:

- the Corporation's 24.5% equity investment in ATCO Structures & Logistics Ltd.;
- the development, operation and support of information systems and technologies, and the provision of billing, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- short term investments and commercial real estate owned by the Corporation in Alberta.

Transactions between segments are eliminated in all reporting of the Corporation's consolidated financial information. For additional information on the Corporation's segments, refer to Note 4 to the 2011 Interim Financial Statements.

Non-GAAP Measures

The Corporation uses the measures "Funds Generated by Operations", "Adjusted Earnings" and "Adjusted Earnings per Class A and Class B Share" in this MD&A. These measures do not have any standardized meaning under IFRS 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 are defined as earnings attributable to Class A and Class B Shares after adjusting for the timing of revenues and expenses associated with rate regulated activities and equity preferred share dividends. Adjusted Earnings will present earnings from rate regulated activities on the same basis as was used prior to adopting IFRS – that basis being the U.S. accounting principles for rate regulated

activities commonly used by rate regulated companies in Canada. Adjusted Earnings also exclude one-time gains and losses and items that are not in the normal course of business or day-to-day operations. It is management's view that 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 section.

International Financial Reporting Standards

The Corporation has adopted IFRS as the basis of financial reporting commencing with the 2011 Interim Financial Statements. The transition date from Canadian GAAP to IFRS is January 1, 2010, (Transition Date) and comparative data for 2010 has been restated in accordance with IFRS.

The adoption of IFRS has affected the Corporation's financial position and operating results in two significant ways: (1) the Corporation no longer recognizes regulatory assets and liabilities associated with its rate regulated activities, thereby resulting in increased volatility of earnings under IFRS, and (2) the carrying value of certain property, plant and equipment was reduced, and the unamortized gains and losses associated with the Corporation's retirement benefit plans were eliminated, thereby resulting in improved earnings in subsequent periods. These two significant effects are further described below.

IFRS requires expenses to be classified either by nature or by function on the statement of earnings, not as a combination of both. If classified by function on the statement of earnings, the classification by nature is still required to be disclosed in the notes to the financial statements. Therefore the Corporation elected to present costs and expenses solely by their nature as identified in the Results of Operations section in this MD&A.

Accounting for Rate Regulated Activities

Prior to the adoption of IFRS, the Corporation used accounting principles generally accepted in Canada to recognize and measure assets and liabilities arising from rate regulation on its balance sheet. Because there is currently no specific guidance under IFRS for rate regulated entities, the Corporation does not recognize regulatory assets and liabilities under IFRS. At the Transition Date, all assets and liabilities arising from rate regulation were charged to retained earnings.

Rate regulated accounting under Canadian GAAP reduced the volatility of earnings because the Corporation was able to defer the recognition of cash received in advance of future expenditures. Under IFRS, the Corporation records revenues when amounts are billed to customers, but does not recognize the associated costs until they are incurred. Secondly, under Canadian GAAP, the Corporation was able to recognize revenues associated with recoverable costs in advance of future billings to customers. Under IFRS, the Corporation records costs when incurred, but does not recognize their recovery until changes to customer rates are reflected in future customer billings. Thirdly, under Canadian GAAP, the Corporation recognized the earnings that arose from a regulatory decision that pertained to current and prior periods upon receipt of the decision. Under IFRS, the Corporation recognizes earnings when customer rates are changed and amounts are billed to customers. Finally, under Canadian GAAP, amounts relating to intercompany profits that were recognized in rate base by a regulator were not eliminated upon consolidation. Under IFRS, intercompany profits included in property, plant and equipment and intangible assets are eliminated upon consolidation. The Corporation then recognizes those profits in earnings as amounts are billed to customers over the life of the related asset.

These differences between Canadian GAAP and IFRS for rate regulated activities are strictly timing in nature. While Canadian GAAP followed closely the direction of the regulator in terms of deferral accounts and regulatory decisions, IFRS simply recognizes revenues as they are billed through the earnings statement. It is more volatile, but it is all timing.

Adjusted Earnings are a key measure of segment earnings used by management for purposes of assessing segment performance and allocating resources. Furthermore, it is management's view that Adjusted Earnings will allow a better assessment of the economics of rate regulation and will facilitate comparability of the Corporation's financial results with peer companies that have either deferred the adoption of IFRS by one year to 2012 as permitted in Canada or utilize U.S. generally accepted accounting principles for rate regulated entities.

The Corporation has disclosed the impacts of rate regulation as an Adjusted Earnings item in this MD&A and in note 4, Segmented Information, to the 2011 Interim Financial Statements.

Property, Plant and Equipment and Retirement Benefit Plans

On transition to IFRS, the Corporation reduced the carrying value of certain property, plant and equipment, mainly power generation assets, to fair value as permitted by IFRS. A revaluation of these assets was not required under Canadian GAAP. The reduction to property, plant and equipment amounted to \$169 million. Consequently, under IFRS, depreciation and amortization expense decreased by \$3 million for the three months ended March 31, 2010, and by \$9 million for the year ended December 31, 2010 as compared to Canadian GAAP.

At the Transition Date, rather than continue to amortize the cumulative unamortized gains and losses associated with the Corporation's defined benefit pension plans and other post employment benefit plans to earnings, the Corporation elected to charge all cumulative unamortized gains and losses to retained earnings. Because cumulative unamortized losses exceeded unamortized gains at the Transition Date, subsequent earnings will be improved. On transition to IFRS, \$103 million was charged to retained earnings. Under IFRS, retirement benefits expense decreased by \$7 million for the three months ended March 31, 2010, and by \$16 million for the year ended December 31, 2010 as compared to Canadian GAAP. Furthermore, under IFRS, the Corporation will record all actuarial gains and losses associated with pension plan assets and retirement benefit obligations in other comprehensive income as permitted by IFRS. These gains and losses will not be recorded in earnings but will be transferred directly to retained earnings.

Other

The transition to IFRS involved a number of other adjustments that did not have a significant effect on the financial position or future earnings of the Corporation. A number of the exemptions taken on transition to IFRS resulted in adjustments being recorded in retained earnings. The adjustments reduced retained earnings by \$4 million. This reduction in retained earnings does not affect the Corporation's ability to pay dividends. A full description of these items is provided in note 3 to the 2011 Interim Financial Statements.

Internal Control Over Financial Reporting

There was no change in the Corporation's internal control over financial reporting that occurred during the period beginning January 1, 2011, and ended on March 31, 2011, that has materially affected, or is reasonably likely to materially affect, the Corporation's internal control over financial reporting.

Results of Operations

SELECTED QUARTERLY INFORMATION

Prepared In Accordance with IFRS

(\$ millions except per share data)	For the Three Months Ended ^{(1) (2) (6)}			
	Mar. 31	Jun. 30	Sep. 30	Dec. 31
2011 ⁽³⁾ (IFRS)				
Revenues	809	-	-	-
Earnings attributable to Class A and Class B Shares	176	-	-	-
Earnings per Class A and Class B Share	1.34	-	-	-
Diluted earnings per Class A and Class B Share	1.33	-	-	-
Adjusted Earnings ⁽⁵⁾	166	-	-	-
Adjusted Earnings per Class A and Class B Share ⁽⁵⁾	1.30	-	-	-
2010 ⁽⁴⁾ (IFRS)				
Revenues	759	656	562	722
Earnings attributable to Class A and Class B Shares	150	77	87	120
Earnings per Class A and Class B Share	1.14	0.56	0.64	0.90
Diluted earnings per Class A and Class B Share	1.14	0.55	0.64	0.90
Adjusted Earnings ⁽⁵⁾	154	70	88	124
Adjusted Earnings per Class A and Class B Share ⁽⁵⁾	1.22	0.55	0.70	0.99

Notes:

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

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

⁽³⁾ Quarterly information for 2011 (other than Adjusted Earnings per Class A and Class B Share) has been extracted from the consolidated financial statements, which have been prepared in accordance with IFRS.

⁽⁴⁾ Quarterly information for 2010 has been restated in accordance with IFRS.

⁽⁵⁾ Refer to the Reconciliation of Adjusted Earnings and Earnings Attributable to Class A and Class B Shares section for a description of the reconciling adjustments.

⁽⁶⁾ The reporting currency is the Canadian dollar.

Prepared in Accordance with Canadian GAAP

Securities regulations require the presentation of selected financial information for the most recent eight quarters. IFRS does not require the restatement of financial information prior to the transition date which was January 1, 2010. Therefore, quarterly information for 2009 is as reported in the 2010 MD&A under Canadian GAAP and does not conform to current presentation under IFRS.

(\$ millions except per share data)	For the Three Months Ended ^{(1) (2) (5)}			
	Mar. 31	Jun. 30	Sep. 30	Dec. 31
2009 ⁽³⁾ (Canadian GAAP)				
Revenues	-	603	537	676
Earnings attributable to Class A and Class B Shares	-	73	121	127
Earnings per Class A and Class B Share	-	0.58	0.96	1.01
Diluted earnings per Class A and Class B Share	-	0.58	0.96	1.01
Adjusted Earnings ⁽⁴⁾	-	74	77	129
Adjusted Earnings per Class A and Class B Share ⁽⁴⁾	-	0.59	0.61	1.02

Notes:

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

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

⁽³⁾ Quarterly information for 2009 (other than Adjusted Earnings and Adjusted Earnings per Class A and Class B Share) was extracted from the consolidated financial statements, which were prepared in accordance with Canadian GAAP.

⁽⁴⁾ Adjusted Earnings were defined in the 2010 MD&A. Please refer to the Significant Non-Operating Financial Items section of that document for a description of the reconciling adjustments.

⁽⁵⁾ The reporting currency is the Canadian dollar.

Principal Factors Affecting Financial Condition and Results of Operations

The principal factors that caused variations in **financial condition** and **results of operations** over the past eight quarters necessary to understand general trends that have developed and the seasonality of the businesses disclosed in the 2010 MD&A remain substantially unchanged except for:

- The adoption of IFRS in 2011 with a transition date of January 1, 2010. Financial information for 2010 has been restated in accordance with IFRS. Financial information for 2009 was prepared in accordance with Canadian GAAP and has not been restated; and
- The transfer on January 1, 2011 of ATCO Resources from the Corporation's parent, ATCO Ltd., to ATCO Power.

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

Adjusted Earnings are earnings attributable to Class A and Class B Shares after adjusting for the timing of revenues and expenses associated with rate regulated activities and equity preferred share dividends. Adjusted Earnings also exclude one-time gains and losses and items that are not in the normal course of business or day-to-day operations. The following table reconciles Adjusted Earnings to earnings attributable to Class A and Class B Shares.

(\$ millions)	For the Three Months Ended March 31		
	2011	2010	Change (2011-2010)
Adjusted Earnings	166	154	8%
Adjustments for Rate Regulated Activities ⁽¹⁾	4	(9)	144%
Dividends on equity preferred shares	6	5	20%
Earnings attributable to Class A and Class B Shares	176	150	17%

(1) Adjustments for Rate Regulated Activities

(\$ millions)	For the Three Months Ended March 31		
	2011	2010	Change (2011-2010)
<i>Additional revenue billed in current period:</i>			
Future removal and site restoration costs	12	11	9%
Retirement benefits	7	2	250%
Transmission and distribution system load balancing	-	5	(100%)
Impact of colder temperatures on revenues	9	-	-
Other	6	7	(14%)
	34	25	36%
<i>Revenue to be billed in future period:</i>			
Deferred income taxes	(12)	(14)	14%
Transmission access payments	(4)	-	-
Transmission and distribution system load balancing	(6)	-	-
Impact of warmer temperatures on revenues	-	(6)	100%
Other	(1)	(4)	75%
	(23)	(24)	4%
<i>Regulatory decisions:</i>			
Regulatory decisions related to current and prior periods	(6)	(9)	33%
<i>Intercompany profits:</i>			
Elimination of intercompany profits related to the construction of property, plant and equipment and intangible assets	(1)	(1)	-
	4	(9)	144%

The adjustments for rate regulated activities, which are strictly timing in nature, generally fall into the four following categories. Certain adjustments may transfer from one category to another depending upon whether more or less revenue has been billed to customers than expected.

(i) Additional revenue billed in the current period

These adjustments reflect the situation where the Corporation records revenues when amounts are billed to customers, but does not recognize the associated costs until they are incurred. This category includes:

- Future removal and site restoration costs, where customers are billed over the life of the associated assets in advance of future expenditures;
- Retirement benefits, where the Corporation recovers the amounts paid under defined benefit pension plans and other post employment benefit plans, which are currently higher than the accrued costs expensed and capitalized;
- ATCO Gas' and ATCO Pipelines' net sales of natural gas to maintain appropriate operating pressures on their distribution and transmission pipeline systems (Load Balancing), which are refunded to customers in future periods; and
- The impact of colder temperatures on ATCO Gas' revenues, where customer rates are based on a forecast of normal temperatures, but colder than normal temperatures will result in more revenue being recovered from customers than forecast. Colder temperatures will result in a refund to customers of excess revenues.

(ii) Revenue to be billed in a future period

These adjustments reflect the situation where the Corporation records costs when incurred, but does not recognize their recovery or refund until changes to customer rates are reflected in future customer billings. This category includes:

- Deferred income taxes, which are not recovered from customers until income taxes are paid;
- ATCO Electric's transmission access payments, where actual costs that vary from the forecast costs included in customer rates are recovered from or refunded to customers in future periods;
- ATCO Gas' and ATCO Pipelines' net purchases of natural gas for Load Balancing, which are recovered from customers in future periods; and
- The impact of warmer temperatures on ATCO Gas' revenues, where customer rates are based on a forecast of normal temperatures, but warmer than normal temperatures will result in less revenue being recovered from customers than forecast. Warmer temperatures will result in a recovery from customers of revenue shortfall.

(iii) Regulatory Decisions

These adjustments reflect the situation where the Corporation recognizes in Adjusted Earnings the impact related to current and prior periods upon receipt of a decision, but IFRS requires that such revenues not be recognized until customer rates are changed and amounts are billed to customers in future periods. For example, the AUC issued decisions in 2010 for ATCO Gas' Carbon Facility (refer to the 2010 MD&A). As these decisions related to prior periods, the Corporation recognized Adjusted Earnings in full in 2010. However, under IFRS, earnings are not recognized upon receipt of the decisions, but instead are recognized when the amounts to be collected from customers are billed in 2010 and 2011.

The change in this category was mainly the result of two significant decisions: the 2010 Carbon decisions described above and a decision regarding ATCO Gas' deferred gas account.

Under Canadian GAAP, in the first and third quarters of 2010, ATCO Gas recorded Adjusted Earnings of \$11 million and \$14 million, respectively, pertaining to decisions for the Carbon Facility. Under IFRS,

these earnings are being recognized starting in the second quarter of 2010 and continuing in 2011 as they are being billed to customers.

Also in the first quarter of 2010 under Canadian GAAP, ATCO Gas recorded a contingent liability and a reduction in Adjusted Earnings of \$8 million for a decision regarding amounts previously recovered from customers for historical transportation imbalances. The AUC's final decision resulted in a reversal of \$1 million of the contingent liability in the third quarter of 2010. Under IFRS, the net \$7 million earnings reduction was recorded in the fourth quarter of 2010 when it was refunded to customers.

(iv) Intercompany profits

This adjustment reflects the situation where, under Canadian GAAP, amounts relating to intercompany profits that were recognized in rate base by a regulator were not eliminated upon consolidation. Under IFRS, intercompany profits included in property, plant and equipment and intangible assets are eliminated upon consolidation. The Corporation then recognizes those profits in earnings as amounts are billed to customers over the life of the related asset.

CONSOLIDATED REVENUES AND ADJUSTED EARNINGS

Revenues for the three months ended March 31, 2011, **increased** by \$50 million (7%) over 2010. This increase was primarily attributable to a \$62 million (26%) increase in the Energy segment mainly due to higher flow through natural gas sales in ATCO Midstream and higher Alberta pool prices in ATCO Power, partially offset by the expiry of the Barking generating plant's revenue contract in ATCO Power. These increases were partially offset by a \$57 million (70%) decrease in revenues in the ATCO Australia segment as the first quarter of 2010 included one-time revenues of \$65 million for the lease of the first unit of the Karratha plant.

Also contributing to the increase in revenues was a \$43 million (10%) increase in the Utilities segment. It is important to note that reported revenues for the Utilities segment have not been adjusted for regulated items as revenues are not viewed by management as a key measure of performance for this segment. This **increase** in revenues in the Utilities segment is mainly due to increased rate base in ATCO Electric and the effect of colder weather in ATCO Gas.

Adjusted Earnings for the three months ended March 31, 2011, **increased** by \$12 million (8%) over 2010. This increase was primarily attributable to an increase of \$17 million (46%) in the Energy segment mainly due to higher Alberta pool prices and related Spark Spreads in ATCO Power and an increase of \$4 million (4%) in the Utilities segment mainly due to increased rate base in ATCO Electric, ATCO Gas and ATCO Pipelines (Utilities).

CONSOLIDATED EXPENSES

(\$ millions)	For the Three Months Ended March 31		
	2011	2010	Change (2011-2010)
Costs and expenses:			
Salaries, wages and benefits	108	79	37%
Energy transmission and transportation	11	2	450%
Plant and equipment maintenance	36	28	29%
Fuel costs	119	76	57%
Purchased power	16	15	7%
Materials and consumables	15	77	(81%)
Franchise fees	62	61	2%
Other expenses	70	75	(7%)
	437	413	6%
Depreciation and amortization	85	82	4%
Interest expense	53	58	(9%)
Income taxes	61	55	11%

Costs and expenses for the three months ended March 31, 2011, **increased** by \$24 million (6%) over the same period in 2010. Fuel costs increased \$43 million primarily due to higher flow through natural gas purchases for NGL extraction in ATCO Midstream. Salaries, wages and benefits increased by \$29 million primarily due to salary escalation and more employees. The reduction in materials and consumables reflects \$62 million of one-time costs of sales recorded in the first quarter of 2010 for the lease of the first unit of the Karratha plant.

For the three months ended March 31, 2011, **interest expense decreased** by \$5 million (9%) compared to the corresponding period in 2010, mainly due to the repayment of non recourse long term debt in ATCO Power and the refinancing of \$125 million 11.4% debentures, which were repaid on August 15, 2010, with \$125 million 4.947% debentures issued on November 18, 2010.

For the three months ended March 31, 2011, **income taxes increased** by \$6 million (11%) compared to the same period in 2010, primarily due to increased earnings before income taxes partially offset by lower income tax rates.

SEGMENTED INFORMATION

(\$ millions)	For the Three Months Ended					Total
	Utilities	Energy	ATCO Australia	Corporate & Other	Intersegment Eliminations	
2011						
Revenues	474	300	24	50	(39)	809
Adjusted Earnings	101	54	4	7	-	166
Adjustments for rate regulated activities ⁽¹⁾	3	-	-	-	1	4
Dividends on equity preferred shares	-	-	-	6	-	6
Earnings attributable to Class A and Class B shares	104	54	4	13	1	176
2010						
Revenues	431	238	81	48	(39)	759
Adjusted Earnings	97	37	5	13	2	154
Adjustments for rate regulated activities ⁽¹⁾	(10)	-	-	-	1	(9)
Dividends on equity preferred shares	-	-	-	5	-	5
Earnings attributable to Class A and Class B Shares	87	37	5	18	3	150

Note:

⁽¹⁾ Refer to the Reconciliation of Adjusted Earnings and Earnings Attributable to Class A and Class B Shares section for a description of the adjustments.

Utilities

Utilities **revenues** for the three months ended March 31, 2011 **increased** by \$43 million (10%) over the corresponding period in 2010. This increase was primarily attributable to increased rate base in ATCO Electric, colder weather and recoveries from customers resulting from the Carbon Storage Facility decisions in ATCO Gas that commenced in the second quarter of 2010. These increases were partially offset by lower revenues due to increased purchases of natural gas by ATCO Gas to maintain appropriate operating pressures in its distribution pipeline system.

Reported revenues for the Utilities segment have not been adjusted for regulatory items as revenues are not viewed by management as a key measure of performance for this segment. As a result changes in revenues in the Utilities segment may not be indicative of a change in Adjusted Earnings due to the timing of recognition of revenues under IFRS as compared to rate regulated accounting.

For the three months ended March 31, 2011, **Adjusted Earnings increased** by \$4 million (4%) over the corresponding period of 2010. The primary reason for the increase in Adjusted Earnings was increased rate base in the Utilities. Partially offsetting these increases were two ATCO Gas decisions which were recorded in the first quarter of 2010: \$11 million of higher earnings related to the 2010 Carbon decision, partially offset by \$8 million lower earnings related to the deferred gas account decision.

Regulatory Developments

Generic Cost of Capital

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 return on equity (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 hearing is scheduled to commence on June 20, 2011 and be completed in the third quarter of 2011, with a final a decision expected in the fourth quarter of 2011.

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 and that the recovery of Federal deferred income taxes for transmission operations be included in customer rates. The inclusion of construction work in progress and Federal deferred income taxes in customer rates would not significantly impact Adjusted Earnings but would result in an improvement to reported earnings under IFRS and cash flows during the construction of the major transmission projects currently being undertaken.

In November 2010, ATCO Electric filed an application requesting interim adjustable rate increases amounting to 37% of the requested increase for transmission operations and 90% of the requested increase for distribution operations, pending the AUC's decision on the 2011 and 2012 general tariff application. ATCO Electric excluded the impact of construction work in progress and the recovery of Federal deferred income taxes from its requested interim rates increases for transmission operations. In December 2010, the AUC issued a decision approving ATCO Electric's interim adjustable rate increases as filed.

On April 13, 2011, the AUC issued a decision on ATCO Electric's 2011 and 2012 general tariff application approving, among other things, the inclusion of construction work in progress and Federal deferred income taxes for transmission operations as requested. There was no significant impact to Adjusted Earnings for the quarter ended March 31, 2011 as a result of the decision given the interim adjustable rate increases previously approved by the AUC. As discussed above, the inclusion of construction work in progress and Federal deferred income taxes in customer rates does not significantly impact Adjusted Earnings but will result in an improvement to reported earnings under IFRS and cash flows in future periods.

Transmission Infrastructure Projects

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. On March 29, 2011, ATCO Electric filed its

facility application with the AUC, with an estimated project cost, excluding capitalized interest during construction, of \$1.6 billion and a mid 2014 in service date. Final approval is not anticipated until the first quarter of 2012. Approval of the facility application is required before construction can commence. It is anticipated that the majority of the project costs will be incurred in 2012 through 2014.

Hanna Region Transmission Development (“HRTD”) Project

In 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 has received approval from the AUC to proceed with the construction of three developments for an estimated cost of \$20 million and is awaiting approval of facility applications filed with the AUC for one further development with an estimated cost of \$730 million. Facility applications for the remaining two developments with an estimated cost of \$50 million are expected to be filed with the AUC by the end of the second quarter of 2011. Final approvals are expected in the first quarter of 2012. It is anticipated that the majority of these costs will be incurred in 2012.

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 was received in April 2011 approving interim adjustable rates effective May 1, 2011, equal to 60% of ATCO Gas’ requested revenue increase. ATCO Gas’ Adjusted Earnings increased by \$3 million in the first quarter of 2011 as a result of this decision. Earnings under IFRS will not be recognized until interim rates are billed to customers starting in May 2011.

Carbon Natural Gas Storage Facility

ATCO Gas owns a 43.5 petajoule natural gas storage facility located at Carbon, Alberta. The Carbon Facility is not used by ATCO Gas for the provision of utility service and the entire storage capacity is leased to ATCO Midstream. On March 29, 2011, ATCO Gas received approval from the AUC for the internal transfer of the Carbon facility from ATCO Gas to ATCO Midstream. The transfer, which will be measured at carrying value, is expected to be completed in the second quarter of 2011.

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.

The AUC issued a decision on May 27, 2010, approving the integration, but requested ATCO Pipelines to submit subsequent applications to address the specific details of (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. On April 20, 2011, the AUC approved ATCO Pipelines' application to address the transition of customers. An application to address the asset swap is expected to be submitted to the AUC in the second 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.

Energy

Effective January 1, 2011, the Corporation separately reports current and comparative segmented information for the ATCO Australia segment. As a result, the Energy segment no longer reports revenues and Adjusted Earnings from its interest in three Australian generating plants, which are now reported within the ATCO Australia segment.

Energy **revenues** for the three months ended March 31, 2011, **increased** by \$62 million (26%) over the corresponding period in 2010. This increase was primarily attributable to higher flow through natural gas sales in ATCO Midstream, and higher pool prices in ATCO Power's power plants in Alberta. These increases were partially offset by decreased revenues at ATCO Power's Barking generating plant in the U.K. due to the expiry of the revenue contract on September 30, 2010.

	For the Three Months Ended March 31		
(\$ millions)	2011	2010	Change (2011-2010)
Adjusted Earnings			
ATCO Power			
Independent Power Plants	25	10	150%
Regulated Power Plants	18	11	64%
	43	21	105%
ATCO Midstream	11	16	(31%)
	54	37	46%

Adjusted Earnings for the three months ended March 31, 2011, **increased** by \$17 million (46%) over the corresponding period of 2010. This increase was primarily attributable to higher pool prices and related Spark Spreads in ATCO Power's power plants in Alberta and higher generation in ATCO Power's Sheerness and Battle River regulated plants due to higher availability. These increases were partially offset by decreased earnings from ATCO Power's Barking generating plant in the U.K. due to the expiry of the revenue contract on September 30, 2010 and lower summer/winter natural gas price differentials for storage (Storage Price Differentials) in ATCO Midstream.

Power Generation

Availability of the generating plants by geographic region:

	For the Three Months Ended March 31		
	2011	2010	Change (2011-2010)
Independent Power Plants ⁽¹⁾			
Canada ⁽²⁾	91.5%	96.5%	(5.0%)
U.K.	96.8%	88.6%	8.2%
Regulated Plants ⁽¹⁾			
Canada	97.4%	83.8%	13.6%

Notes:

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

⁽²⁾ *An unplanned outage to perform preventative maintenance commenced at the Brighton Beach generating plant on February 4, 2011. The generating plant returned to service on April 26, 2011.*

Plant Curtailment at Brighton Beach Generating Plant

On February 4, 2011, ATCO Power's Brighton Beach generating plant curtailed its output for preventative maintenance based on input from one of its equipment manufacturers. Examination of the plant's steam turbine revealed cracking associated with the turbine blades. The outage to make an interim repair extended to April 26, 2011 with a permanent repair to be undertaken at a date yet to be determined. This curtailment is not expected to have a material impact on the Corporation's 2011 earnings.

Merchant Operations

Changes in Spark Spread currently affect the results of approximately 713 MW of plant capacity out of a total worldwide capacity owned by ATCO Power of 2,618 MW. This capacity is comprised of approximately 503 MW in Alberta out of a total Alberta-owned capacity of 1,883 MW and 210 MW in the U.K. out of a total U.K.-owned capacity of 255 MW.

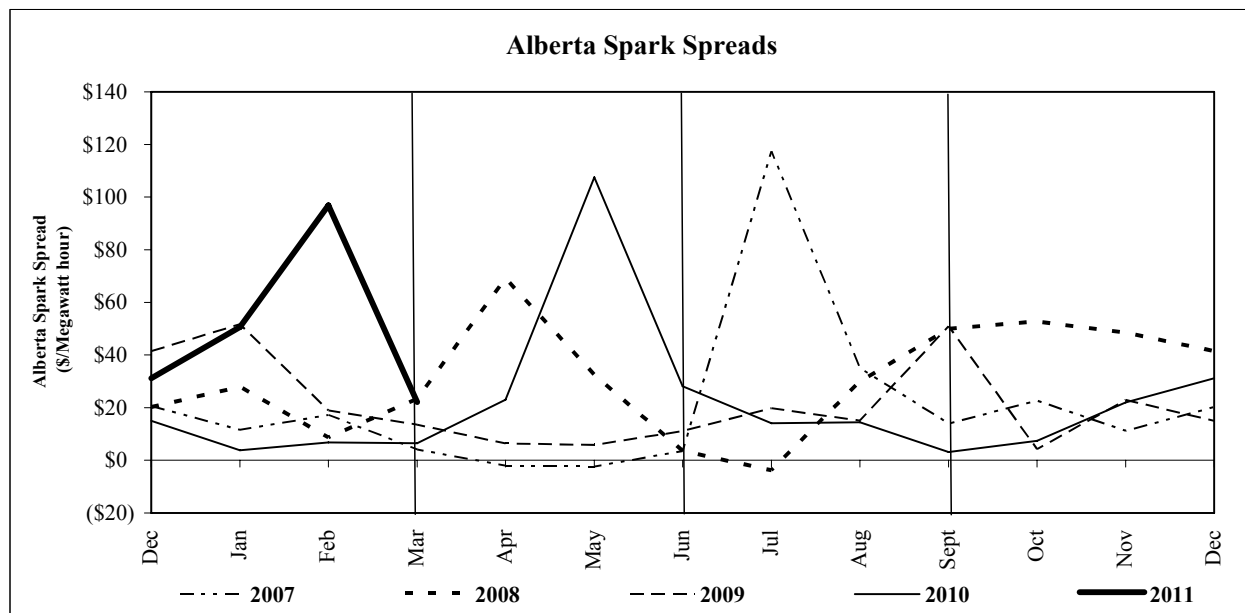
The Corporation's merchant power sales are affected by volatility in power and natural gas prices caused by market forces such as fluctuating supply and demand for electricity. The Corporation manages this volatility through its adoption of asset optimization strategies in accordance with its risk management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

Alberta Merchant Operations

The majority of ATCO Power's electricity sales to the Alberta Power Pool are from natural gas-fired generating plants and, as a result, earnings are affected by natural gas prices and Alberta Power Pool prices. The average Alberta Power Pool electricity prices, natural gas prices and resulting Spark Spreads for the three months ended March 31, 2011 are shown in the following table:

	For the Three Months Ended March 31		
	2011	2010	Change (2011-2010)
Average Alberta Power Pool electricity price (\$/MWh)	82.05	40.78	101%
Average natural gas prices (\$/GJ)	3.57	4.69	(24%)
Average Spark Spread (\$/MWh)	55.20	5.63	880%

The following chart demonstrates the volatility of Alberta Spark Spreads experienced by ATCO Power for the period of December 2006 to March 2011:



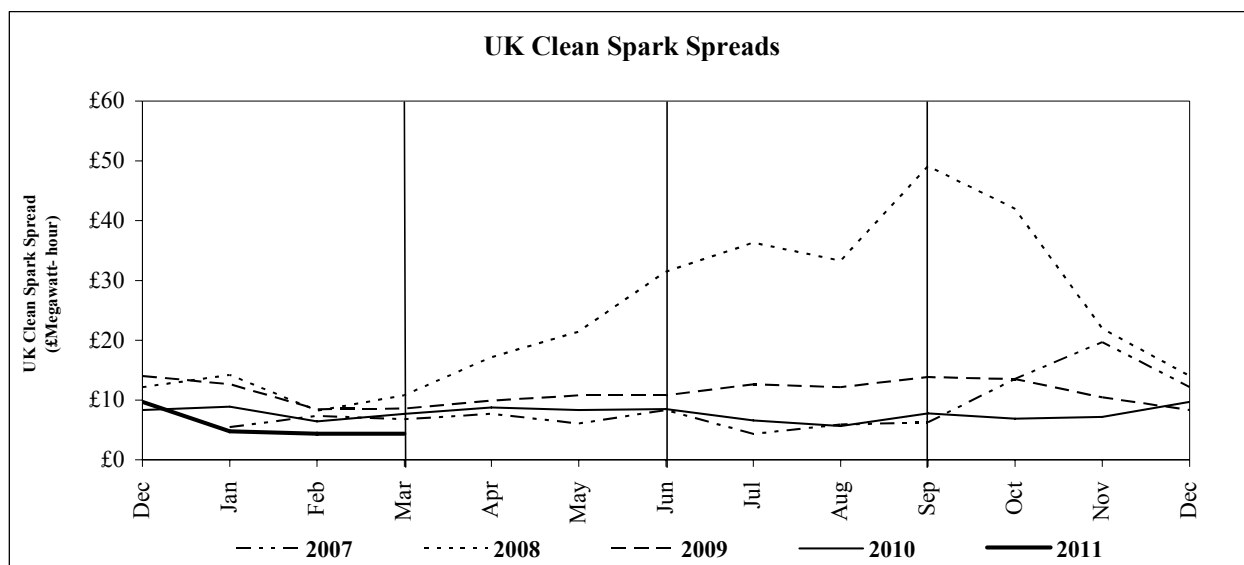
U.K. Merchant Operations

As of October 1, 2010, the majority of ATCO Power's Barking generating plant capacity is exposed to market prices for electricity, natural gas and emissions allowances. ATCO Power owns 255 MW of the plant's capacity, of which 45 MW has been contracted for a one year term commencing October 1, 2010.

The average U.K. power prices, natural gas prices, emissions allowances and resulting Spark Spreads for the three months ended March 31, 2011 are shown in the following table:

	For the Three Months Ended March 31		
	2011	2010	Change (2011-2010)
Average U.K. power price (£/MWh)	48.59	36.40	33%
Average natural gas prices (£/GJ)	5.40	3.36	61%
Average emissions allowances prices (£/tonne of CO2)	13.09	11.63	13%
Average Spark Spread (£/MWh)	4.50	7.67	(41%)

Barking’s actual merchant sales are not necessarily sold using the same Spark Spread indicator used in the table above and the graph below. The table and graph depict the spot market, whereas the Barking generating plant generally utilizes forward power sales. The following chart demonstrates the volatility of U.K. Spark Spreads since the beginning of 2007:



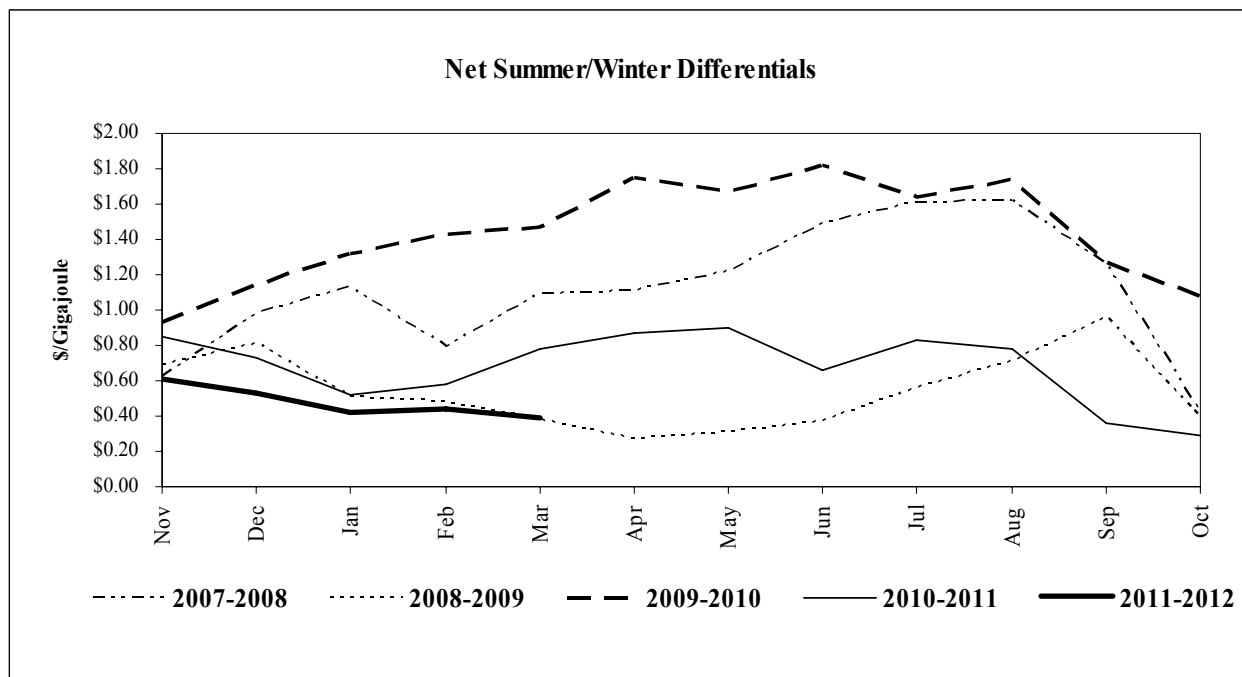
ATCO Midstream

Storage Operations

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

Storage Price Differentials can be volatile, as shown in the following graph, which illustrates a range of seasonal differentials experienced during the storage periods from the 2007-2008 storage year to the 2011-2012 storage year. The graph shows the storage differentials for the upcoming storage season (April to October injection and November to March withdrawal). For example, the Storage Price Differential for the April 2011 to March 2012 storage season was \$0.61 in November 2010, \$0.53 in December 2010 and \$0.42 in January 2011. Storage Price Differentials at any point in time may not be

indicative of the storage revenue and earnings for the same period due to the types of contracts and the timing of the revenue recognition associated with these contracts.

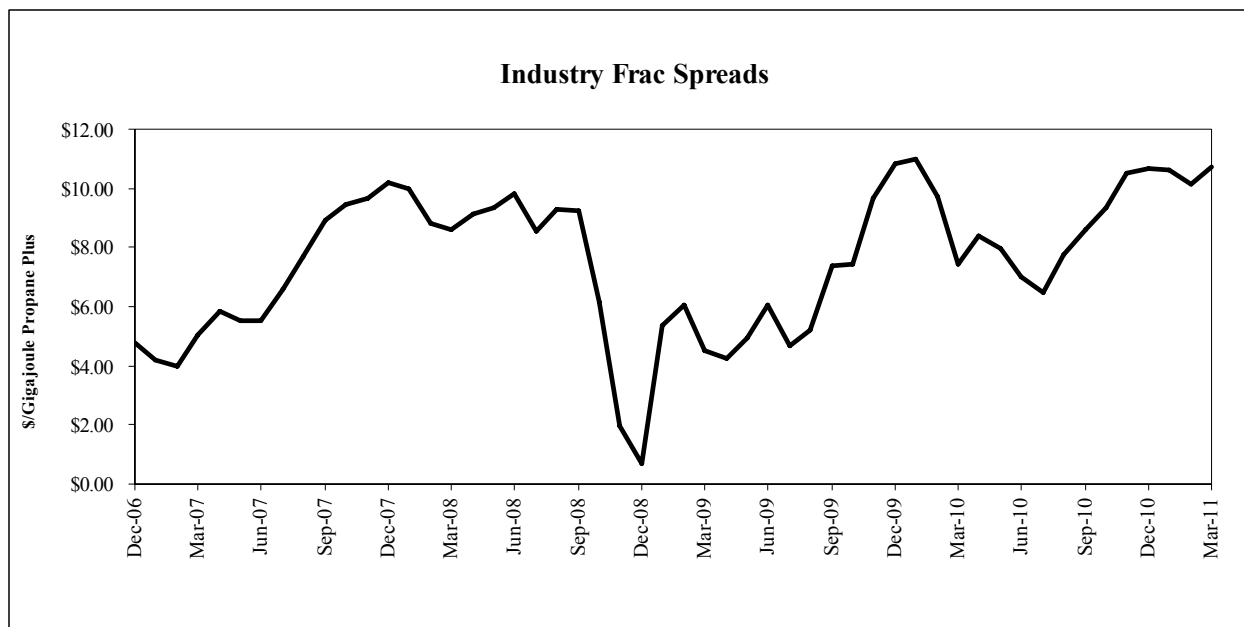


Fluctuations in Storage Price Differentials affect ATCO Midstream’s earnings and cash flow from operations. At current values, a \$0.25 change in the Storage Price Differentials impacts the Corporation’s annual consolidated earnings attributable to Class A and Class B Shares by approximately \$8.0 million.

NGL Extraction Operations

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

The majority of ATCO Midstream’s NGL extraction operations involve the extraction of NGL from natural gas and the replacement (on a heat content equivalent basis) of the NGL extracted with shrinkage gas. For Propane Plus, the difference between the price of natural gas and the value of the liquids extracted is commonly referred to as the Frac Spread. Frac Spreads vary with fluctuations in the price of natural gas and the prices of the applicable liquids extracted. Frac Spreads can be volatile, as shown in the following graph, which illustrates monthly Frac Spreads during the period of December 2006 to March 2011.



Note:

⁽¹⁾ The above chart represents measurements of industry Frac Spreads in Alberta, as reported by an independent consultant. The average Frac Spread for the three months ended March 31, 2011 was \$10.50 per gigajoule compared to \$9.39 per gigajoule for the three months ended March 31, 2010.

Historically, fluctuations in Frac Spreads directly affected ATCO Midstream’s earnings and cash flow from operations. More recently, owing to increased competition, the positive effect from higher Frac Spreads is being affected by increased costs of obtaining natural gas for extraction. Therefore, a pure correlation of Frac Spreads to earnings cannot be made. Earnings from ATCO Midstream’s NGL operations in both the first quarter of 2011 and 2010 were approximately the same.

ATCO Australia

ATCO Australia’s revenues **decreased** by \$57 million (70%) for the three months ended March 31, 2011, compared to the corresponding period in 2010. Revenues in 2010 included one-time revenues of \$65 million related to the lease of the first unit of the Karratha plant. Otherwise operating revenues have increased \$8 million, primarily due to the fact that both Karratha units were operating in 2011 compared to only one unit in 2010.

Adjusted Earnings for the three months ended March 31, 2011, were essentially **unchanged** compared to the corresponding period in 2010. The \$2 million lease accounting gain recognized in the first quarter of 2010 on the completion of the first unit of the Karratha plant was offset by higher operating earnings at the Karratha plant due to the commencement of operations of the first unit on February 14, 2010, compared to both units being in operation in 2011.

Availability of the generating plants in Australia for the three months ended March 31, 2011 was 99.8 % compared to 94.7% in the corresponding period in 2010, an increase of 5.1%.

Corporate & Other

Adjusted Earnings for the three months ended March 31, 2011, were \$7 million, a **decrease** of \$6 million (46%) compared to the corresponding period of 2010. This decrease was due to higher salaries, wages and benefits partially offset by lower share appreciation rights expense.

Liquidity and Capital Resources

A major portion of the Corporation's earnings attributable to Class A and Class B Shares and Funds Generated by Operations is generated from its utility operations. Canadian Utilities and its wholly owned subsidiary, CU Inc., have access to 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 Three Months Ended		
	March 31		
	2011	2010	Change (2011-2010)
Cash position, beginning of period	540	796	(32%)
Cash provided by (used in)			
Operating activities:			
Funds Generated by Operations	402	310	30%
Changes in non-cash working capital	26	55	(53%)
Cash flow from operations	428	365	17%
Investing activities	(209)	(203)	(3%)
Financing activities	(100)	(108)	7%
Foreign currency impact on cash balances	2	(13)	115%
Cash position, end of period	661	837	(21%)

OPERATING ACTIVITIES

For the three months ended March 31, 2011, **Funds Generated by Operations** were \$402 million, an **increase** of \$92 million (30%) over the corresponding period of 2010. This increase was primarily due to higher earnings and increased availability incentive receipts in ATCO Power. For the three months ended March 31, 2011, **cash flow from operations** was \$428 million, an **increase** of \$63 million (17%) over the corresponding period of 2010. This increase was primarily due to the increase in Funds Generated by Operations, partially offset by a reduction in changes in non-cash working capital. The reduction in changes in non-cash working capital was primarily due to lower receipts from storage customers in ATCO Midstream and lower payments for maintenance costs in ATCO Power due to an outage at the Sheerness plant which occurred in 2010. These decreases were partially offset by higher receipts in ATCO Power due to higher Alberta Spark Spreads.

INVESTING ACTIVITIES

For the three months ended March 31, 2011, **cash used in investing activities increased** by 3% to \$209 million compared to the corresponding period of 2010. This increase was mainly due to increased capital investment in regulated transmission infrastructure projects in ATCO Electric, partially offset by the construction of the Karratha plant which was completed in 2010.

FINANCING ACTIVITIES

For the three months ended March 31, 2011, the Corporation **repaid** \$8 million of non-recourse long term debt in ATCO Power.

On March 1, 2010, the Corporation commenced a **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A Shares. The bid expired on February 28, 2011. From March 1, 2010, to February 28, 2011, 138,850 shares were purchased all of which were purchased in 2010. On March 1, 2011, the Corporation commenced a new **normal course issuer bid** for the purchase of up to 3% of the outstanding Class A Shares. The bid will expire on February 29, 2012. From March 1, 2011, to April 27, 2011, 4,000 shares have been purchased.

For the three months ended March 31, 2011, there were no **purchases** of Class A Shares under the Corporation's normal course issuer bid compared to \$1 million in the corresponding period of 2010. For the three months ended March 31, 2011, and 2010, **issues** of Class A Shares due to stock option exercises were nil.

Total **dividends paid to Class A and Class B share owners** for the three months ended March 31, 2011, **increased** by 8% to \$51 million over the corresponding period of 2010. For the three months ended March 31, 2011, the **quarterly dividend** payment on the Corporation's Class A and Class B Shares was **increased** by \$0.025 to \$0.4025 per share over 2010. On April 13, 2011, the Board of Directors declared the second quarter dividend of \$0.4025 per share. The Corporation has increased its annual common share dividend each year since its inception as a holding company in 1972. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

FOREIGN CURRENCY TRANSLATION

For the three months ended March 31, 2011, **foreign currency translation increased** the Corporation's cash position by \$2 million due to changes in the U.K. exchange rate used for balance sheet translations.

SHORT TERM INVESTMENT POLICY

The Corporation has a long-standing policy not to invest any of its cash balances in asset-backed securities. Cash and short term investment credit risk is reduced by investing approximately 91% in short term money market instruments of Canadian financial institutions and Government of Canada treasury bills as at March 31, 2011.

LINES OF CREDIT

At March 31, 2011, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

	Total	Used	Available
(\$ millions)			
Long term committed	329	3	326
Short term committed	600	23	577
Uncommitted	53	8	45
Total	982	34	948

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

CONTRACTUAL OBLIGATIONS

Contractual obligations disclosed in the 2010 MD&A remain substantially unchanged as at March 31, 2011.

Share Capital

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

At April 27, 2011, the Corporation had outstanding 87,079,450 Class A Shares, 40,407,649 Class B Shares and options to purchase 732,550 Class A Shares.

Business Risks

Information contained in the 2010 MD&A related to Business Risks remains substantially unchanged.

Future Accounting Changes

Certain new or revised standards or interpretations have been issued by the IASB or IFRIC that are not required to be adopted in the current period. The Corporation has not early adopted these standards or interpretations.

IFRS 9 *Financial Instruments*, effective for annual periods beginning on or after January 1, 2013, is part of the IASB's project to replace IAS 39 *Financial Instruments: Recognition and Measurement*. The Corporation is evaluating the potential effect of this new standard.

There are no other standards and interpretations that have been issued, but are not yet effective, that the Corporation anticipates will have a material effect on the consolidated financial statements once adopted.

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.

Glossary

Adjusted Earnings means earnings attributable to Class A and Class B Shares after adjusting for the timing of revenues and expenses associated with rate regulated activities and equity preferred share dividends. Adjusted Earnings will present earnings from rate regulated activities on the same basis as was used prior to adopting IFRS – that basis being the U.S. accounting principles for rate regulated activities commonly used by rate regulated companies in Canada. Adjusted Earnings also exclude one-time gains and losses and items that are not in the normal course of business or day-to-day operations. Refer to Reconciliation of Adjusted Earnings and Earnings Attributable to Class A and Class B Shares section for a description of all adjustments.

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

AESO means the Alberta Electric System Operator.

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

ASL means ATCO Structures & Logistics Ltd.

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 GAAP means Canadian generally accepted accounting principles that were in effect prior to the adoption of IFRS effective January 1, 2010.

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

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

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

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

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

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.

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

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

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

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

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

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

U.K. means United Kingdom.

U.S. means United States of America.

Additional Information

ATCO Ltd. has published its unaudited consolidated financial statements and its MD&A for the three months ended March 31, 2011. Copies of these documents may be obtained upon request from the Corporate Secretary of ATCO Ltd. at 1400 ATCO Centre, 909-11th Avenue S.W., Calgary, Alberta, T2R 1N6, telephone 403-292-7500 or fax 403-292-7623.

Canadian Utilities Limited
Consolidated Statement of Earnings
(Millions of Canadian Dollars except per share data)

	Note	Three Months Ended	
		March 31	
		2011	2010
Revenues	8	\$ 809	\$ 759
Costs and expenses			
Salaries, wages and benefits	12	(108)	(79)
Energy transmission and transportation		(11)	(2)
Plant and equipment maintenance		(36)	(28)
Fuel costs		(119)	(76)
Purchased power		(16)	(15)
Materials and consumables		(15)	(77)
Depreciation and amortization	7	(85)	(82)
Franchise fees		(62)	(61)
Other		(70)	(75)
		(522)	(495)
Earnings from investment in ATCO Structures & Logistics		6	5
Other income (expense)		(2)	(1)
Operating profit		291	268
Interest income		5	-
Interest expense		(53)	(58)
Net finance costs		(48)	(58)
Earnings before income taxes		243	210
Income taxes		(61)	(55)
Earnings for the period		\$ 182	\$ 155
Earnings attributable to:			
Class A and Class B shares		\$ 176	\$ 150
Equity preferred share owners of subsidiary		6	5
		\$ 182	\$ 155
Earnings per Class A and Class B share	9	\$ 1.34	\$ 1.14
Diluted earnings per Class A and Class B share	9	\$ 1.33	\$ 1.14

Canadian Utilities Limited
Consolidated Statement of Comprehensive Income
(Millions of Canadian Dollars)

	Note	Three Months Ended	
		March 31	
		2011	2010
Earnings for the period		\$ 182	\$ 155
Other comprehensive income, net of income taxes:			
Actuarial gain (loss) on retirement benefits ⁽¹⁾	12	2	(65)
Cash flow hedges ⁽²⁾		-	(1)
Foreign currency translation adjustment ⁽³⁾		-	(19)
		2	(85)
Comprehensive income for the period		\$ 184	\$ 70
Comprehensive income attributable to:			
Class A and Class B shares		\$ 178	\$ 65
Equity preferred share owners of subsidiary		6	5
		\$ 184	\$ 70

⁽¹⁾ Net of income taxes of \$1 million and \$22 million, respectively.

⁽²⁾ Net of income taxes of Nil.

⁽³⁾ Net of income taxes of Nil.

Canadian Utilities Limited
Consolidated Balance Sheet
(Millions of Canadian Dollars)

	Note	March 31 2011	December 31 2010	January 1 2010
ASSETS				
Current assets				
Cash and cash equivalents		\$ 661	\$ 540	\$ 796
Accounts receivable		316	356	354
Finance lease receivables	8	13	11	8
Inventories		80	82	80
Prepaid expenses and other current assets		29	50	49
		1,099	1,039	1,287
Non-current assets				
Property, plant and equipment	7	7,563	7,357	7,026
Intangibles		259	255	242
Investment in ATCO Structures & Logistics		141	137	120
Finance lease receivables	8	535	479	345
Other assets		57	50	42
Total assets		\$ 9,654	\$ 9,317	\$ 9,062
LIABILITIES				
Current liabilities				
Accounts payable and accrued liabilities		\$ 415	\$ 406	\$ 394
Other current liabilities		14	22	18
Long term debt		103	103	128
Non-recourse long term debt		46	38	49
		578	569	589
Non-current liabilities				
Deferred income tax liabilities		419	374	355
Provisions		113	112	97
Retirement benefit obligations	12	277	282	58
Long term debt		2,958	2,960	2,977
Non-recourse long term debt		369	303	355
Other liabilities		1,039	1,000	991
Total liabilities		5,753	5,600	5,422
EQUITY				
Equity preferred shares		505	505	505
Equity preferred shares of subsidiary corporation		343	343	270
Class A and Class B share owners' equity				
Class A and Class B shares	9	616	533	528
Contributed surplus		-	1	3
Retained earnings		2,447	2,345	2,337
Accumulated other comprehensive income		(10)	(10)	(3)
		3,053	2,869	2,865
Total equity		3,901	3,717	3,640
Total liabilities and equity		\$ 9,654	\$ 9,317	\$ 9,062

Canadian Utilities Limited
Consolidated Statement of Changes in Equity

(Millions of Canadian Dollars)

	Note	Class A and Class B Shares	Equity Preferred Shares ⁽¹⁾	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Total Equity
At January 1, 2010 <i>(as restated)</i>		\$ 528	\$ 775	\$ 3	\$ 2,337	\$ (3)	\$ 3,640
Changes in accounting policy							-
Earnings for the period		-	-	-	155	-	155
Shares purchased and cancelled		-	-	-	(1)	-	(1)
Dividends		-	-	-	(58)	-	(58)
Share based compensation		-	-	(3)	-	-	(3)
Other comprehensive income		-	-	-	-	(85)	(85)
Actuarial gain (loss) transferred to retained earnings		-	-	-	(65)	65	-
At March 31, 2010		\$ 528	\$ 775	\$ -	\$ 2,368	\$ (23)	\$ 3,648
At December 31, 2010		\$ 533	\$ 848	\$ 1	\$ 2,345	\$ (10)	\$ 3,717
Earnings for the period		-	-	-	182	-	182
Shares issued	5	83	-	-	-	-	83
Dividends		-	-	-	(63)	-	(63)
Share based compensation		-	-	(1)	(2)	-	(3)
Other comprehensive income		-	-	-	-	2	2
Actuarial gain (loss) transferred to retained earnings		-	-	-	2	(2)	-
Other	5	-	-	-	(17)	-	(17)
At March 31, 2011		\$ 616	\$ 848	\$ -	\$ 2,447	\$ (10)	\$ 3,901

¹ includes equity preferred shares and equity preferred shares of subsidiary corporation

Canadian Utilities Limited
Consolidated Statement of Cash Flows
(Millions of Canadian Dollars)

		Three Months Ended	
		March 31	
	Note	2011	2010
Operating activities			
Earnings for the period		\$ 182	\$ 155
Adjustments for:			
Depreciation and amortization		85	82
Earnings from investment in ATCO Structures & Logistics		(6)	(5)
Dividends received from ATCO Structures & Logistics		2	2
Income taxes		59	52
Unearned availability incentives		15	(4)
Contributions by utility customers for extensions to plant		22	19
Net finance costs		48	58
Income taxes paid		(26)	(39)
Other		21	(10)
		402	310
Changes in non-cash working capital	12	26	55
Cash flow from operations		428	365
Investing activities			
Purchase of property, plant and equipment		(195)	(182)
Purchase of intangibles		(12)	(5)
Changes in non-cash working capital	12	(7)	(16)
Other		5	-
		(209)	(203)
Financing activities			
Repayment of non-recourse long term debt		(8)	(11)
Purchase of Class A shares		-	(1)
Dividends paid on equity preferred shares of subsidiary		(12)	(11)
Dividends paid to Class A and Class B share owners		(51)	(47)
Interest paid		(30)	(37)
Other		1	(1)
		(100)	(108)
Foreign currency translation		2	(13)
Cash position ⁽¹⁾			
Increase		121	41
Beginning of period		540	796
End of period		\$ 661	\$ 837

⁽¹⁾ Cash position includes \$63 million (2010 - \$78 million) which is only available for use in joint operations.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2011

(tabular amounts in millions of Canadian dollars)

1. CORPORATE INFORMATION

Alberta-based Canadian Utilities Limited is engaged in Utilities (pipelines, natural gas and electricity transmission and distribution), Energy (power generation, natural gas gathering, processing, storage and liquids extraction) and Technologies (business systems solutions). Canadian Utilities Limited is domiciled in Canada, and is listed on the Toronto Stock Exchange. Its registered office is at 1400, 909-11th Avenue SW, Calgary, Alberta, T2R 1N6. The Corporation is principally controlled by ATCO Ltd. and its controlling share owner, R.D. Southern.

These consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries, including a proportionate share of joint venture investments and an equity accounted for investment in ATCO Structures & Logistics (“the Corporation”). The consolidated financial statements were authorized for issue by the Audit Committee of the Board of Directors on April 28, 2011.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Financial Statement Presentation and Consolidation

The accompanying interim consolidated financial statements have been prepared in accordance with International Accounting Standard (“IAS”) 34 *Interim Financial Reporting* using accounting policies consistent with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”) and interpretations of the IFRS Interpretations Committee (“IFRIC”). These interim consolidated financial statements also comply with IFRS 1 *First-time Adoption of IFRS*. They should be read in conjunction with the consolidated financial statements and related notes included in the Corporation’s Financial Information contained in its 2010 Annual Report. Accordingly, the Corporation has commenced reporting on this basis in these interim consolidated financial statements. In this context, the term “Canadian GAAP” refers to generally accepted accounting principles before the adoption of IFRS.

Subject to certain transition elections disclosed in Note 3, the Corporation has consistently applied the same accounting policies in its opening IFRS consolidated balance sheet at January 1, 2010, and throughout all periods presented, as if these policies had always been in effect. Previously, the Corporation prepared its consolidated annual and consolidated interim financial statements in accordance with Canadian GAAP. Note 3 discloses reconciliations to IFRS from the previously published Canadian GAAP primary financial statements, including the nature and effect of significant changes in accounting policies from those used in the Corporation’s consolidated financial statements for the year ended December 31, 2010. Comparative figures for 2010 in these consolidated financial statements have been restated to give effect to these changes.

The policies applied in these interim consolidated financial statements are based on IFRS issued and outstanding as of April 28, 2011. Any subsequent changes to IFRS that are given effect in the

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Corporation's annual consolidated financial statements for the year ending December 31, 2011 could result in restatement of these interim consolidated financial statements, including the transition adjustments recognized on transition to IFRS.

Joint Arrangements

Significant joint arrangements included in the consolidated financial statements at March 31, 2011 are listed below, and consist principally of power generation plants.

Jointly controlled assets involve the joint control and joint ownership by the venturers of assets contributed or acquired for the venture. Each venturer may take a share of the output from the assets and each bears an agreed share of the expenses incurred. The Corporation accounts for its interests in jointly controlled assets using the proportionate consolidation method of accounting whereby the Corporation's share of assets, liabilities, revenues and expenses is included in the respective consolidated accounts.

Jointly controlled entities involve the establishment of a corporation, partnership or other entity in which the venturers each have an interest. The venturers have rights to a share of the profits and output generated from the assets controlled by the entity. Under IFRS, venturers have the option of recognizing their interest in a jointly controlled entity using the proportionate consolidation or equity methods of accounting. The Corporation has chosen to use the proportionate consolidation method whereby the Corporation's share of assets, liabilities, revenues and expenses are included in the respective consolidated accounts.

Significant Joint Arrangements	Operating Jurisdiction	Ownership %	Principal Activity
<i>Jointly Controlled Assets</i>			
Energy:			
Sheerness Generating Plant	Canada	50.0	Power generation
Muskeg River Cogeneration Plant	Canada	70.0	Power generation
Edmonton Ethane Extraction Plant	Canada	51.3	Natural gas liquids extraction
Empress Gas Liquids Straddle Plant	Canada	12.2	Natural gas liquids extraction
<i>Jointly Controlled Entities</i>			
Energy:			
Barking Generating Plant	United Kingdom	25.5	Power generation
Joffre Cogeneration Plant	Canada	40.0	Power generation
McMahon Cogeneration Plant	Canada	50.0	Power generation
ATCO Australia:			
Osborne Cogeneration Plant	Australia	50.0	Power generation
Structures & Logistics:			
Tecno Fast ATCO S.A.	Chile	50.0	Modular structures

Rate Regulation

ATCO Electric and its subsidiaries, Northland Utilities (NWT), Northland Utilities (Yellowknife) and Yukon Electrical, the ATCO Gas and ATCO Pipelines divisions of ATCO Gas and Pipelines Ltd., and CU Water, the assets of which were sold in 2010, are wholly owned subsidiaries of Canadian Utilities Limited's wholly owned subsidiary, CU Inc., and are collectively referred to in these consolidated financial statements as the "utilities".

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Nature and economic effects of rate regulation

ATCO Electric, ATCO Gas, ATCO Pipelines and CU Water are regulated by the Alberta Utilities Commission (“AUC”). Yukon Electrical is regulated by the Yukon Energy Board, and Northland Utilities (Yellowknife) and Northland Utilities (NWT) are regulated by the Northwest Territories Public Utilities Board. The regulators administer 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 regulators establish 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. Whereas actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

Rate base for each utility is the aggregate of the regulator 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 regulator approves rates of return for the debt and preferred share components of rate base based on the actual or forecast weighted average cost of each utility’s debt and preferred shares and establishes the capital structure for each utility.

Under the cost of service methodology, the utility seeks approval for its revenue requirement either through submission of general rate applications to the regulator or a negotiated settlement process with interested parties. In the latter case, the regulator monitors the negotiated settlement process and any agreement that is reached is subject to the regulator’s approval. The regulator may approve interim rates or approve the recovery of costs on a placeholder basis, subject to final determination.

The Battle River and Sheerness generating plants were regulated by the AUC until December 31, 2000 but are now governed by legislatively mandated Power Purchase Arrangements (“PPAs”) that were approved by the AUC. 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. For PPAs expiring prior to 2019, ATCO Power 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 the 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.

Financial statement effects of rate regulation

In the absence of a rate regulated standard under IFRS, the utilities do not recognize assets and liabilities from rate regulated activities as may be directed by regulatory decisions. Instead, the utilities record revenues in earnings when amounts are billed to customers through customer rates consistent with the underlying rate design as mandated by the regulator (see revenue recognition policy below). Operating costs and expenses are recorded when incurred. When the costs are incurred in the construction of an

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

asset and the benefits received meet the recognition criteria of an asset, the costs are included as part of the related property, plant and equipment or intangible asset.

Segmented Information

Financial information that adjusts IFRS results to show the effect of rate regulation is used by the Corporation's Board of Directors and Office of the Chairman to evaluate the performance of operating segments and determine resource allocation between operating segments. The Office of the Chairman, comprised of the Chairman of the Board, the President and Chief Executive Officer and six other senior executives, is determined to be the Chief Operating Decision Maker and it assesses performance of operations principally on the basis of earnings adjusted for regulatory items as shown in the segmented information disclosed in note 4.

Significant Judgments and Estimates

The preparation of the Corporation's consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of policies and 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 ongoing basis, management reviews its estimates, particularly those related to revenue recognition, depreciation and amortization methods, useful lives and impairment of long-lived assets, duration of interest capitalization for qualifying assets, amortization of unearned availability incentives, asset retirement obligations, retirement 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. Revisions to accounting estimates are recognized in the period in which the estimate is revised if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods.

Revenue Recognition

Revenues from the regulated distribution of natural gas and the regulated distribution of electricity include variable charges, which are recognized on the basis of meter readings upon delivery of the respective commodity to customers and include an estimate of usage not yet billed, and fixed charges, based on the provision of the distribution service during the period.

Revenues for the use of regulated transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from the regulated transmission of natural gas are recognized on the basis of contractual arrangements. For certain services, revenues are recognized on the basis of meter readings upon delivery of natural gas to customers and include an estimate of usage not yet billed.

Measurement of the estimate of usage not yet billed is based on historical consumption patterns. Management applies judgment to the measurement of the estimated consumption and to the valuation of that consumption.

Certain additions to property, plant and equipment, primarily in the utilities, are made with the assistance of non-refundable cash contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. Since the contributions will provide customers with ongoing access to the supply of natural gas or

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

electricity, these contributions are classified as deferred revenue and are recognized over the life of the related asset.

Revenues from power generating plants are recognized upon delivery of output or upon availability of delivery as prescribed by contractual arrangements. In addition, incentives and penalties associated with the Battle River and Sheerness PPAs are recognized as described under the accounting policy for unearned availability incentives.

Revenues from natural gas storage and processing capacity are recognized on the basis of contractual arrangements, and revenues from the sale of natural gas liquids are recognized upon delivery.

Revenues resulting from the supply of contracted products and services are recorded by the percentage of completion method; full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services are provided. Billings in excess of earned revenue are classified as deferred revenue included in other liabilities on the consolidated balance sheet.

Short Term Employee Benefits

The cost of short term employee benefits, which includes wages, salaries, social security contributions, short term compensated absences, bonuses and non-monetary benefits such as medical care, is recognized as an expense in salaries, wages and benefits as employees render service. When the services of employees are used in the construction of an asset and the benefits received meet the recognition criteria of an asset, the cost of short term employee benefits is included as part of the related property, plant and equipment or intangible asset.

Franchise Fees

Franchise fees are charged to the utilities by municipal governments for the exclusive right to provide service in their community. These costs are charged to the related customers through rates that must first be approved by the regulator. Franchise fee revenues and expenses are, therefore, recognized separately and are not recorded on a net basis.

Income Taxes

Income taxes represent the sum of current and deferred taxes. Income taxes are recognized in earnings or in equity to the extent that equity items are affected.

Current taxes are based on taxable earnings, which differ from earnings as reported in the statement of earnings because it excludes items that are taxable or deductible in other years and items that are neither taxable nor deductible. The Corporation's liability for current tax is calculated using rates that have been enacted or substantively enacted as of the balance sheet date.

Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation and establishes provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured on the basis of a probability weighting of possible outcomes.

Deferred income taxes are provided, using the liability method, on differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for accounting purposes ("temporary differences").

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred income tax assets are recognized on deductible temporary differences and carry forward balances of unused tax losses or credits only to the extent that it is probable that taxable earnings will be available against which these items can be applied. Deferred income tax assets and liabilities are not recognized if the temporary difference arises from the initial recognition of goodwill or from the initial recognition of other assets and liabilities in a transaction (other than a business combination) that, at the time of the transaction, affects neither accounting earnings nor taxable earnings.

Deferred income tax assets and liabilities are recognized on temporary differences arising on investments in subsidiaries and joint ventures, except where the Corporation is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates that have been enacted or substantively enacted by the balance sheet date. If the expected tax rates change, deferred income taxes are adjusted to the new rates and the adjustment is booked to either earnings or equity, depending on the nature of the underlying temporary difference.

The carrying amount of deferred income tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable earnings will be available to allow all or part of the deferred income tax asset to be realized. Unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become probable that future taxable earnings will allow the deferred income tax assets to be realized.

Deferred income tax assets and liabilities are offset when there is a legally enforceable right to set off tax assets against tax liabilities, and when they relate to income taxes levied by the same taxation authority.

Cash and Cash Equivalents

Cash equivalents consist of bankers' acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short term investments with maturities generally of 90 days or less at purchase.

Inventories

Inventories are valued at the lower of cost or net realizable value. The cost of inventories is assigned using the weighted average cost method. Net realizable value is the estimated selling price in the ordinary course of business, less applicable variable selling expenses.

The cost of inventories is comprised of all costs of purchase, costs of conversion and other costs to bring the inventories to their present condition and location. The costs of purchase comprise the purchase price, import duties, and non-recoverable taxes, and transport, handling and other costs directly attributable to the acquisition of finished goods, materials or services. The costs of conversion include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Property, Plant and Equipment

Property, plant and equipment are recorded at cost less accumulated depreciation and accumulated impairment losses and include capitalized interest incurred during construction. Cost includes expenditures that are directly attributable to the acquisition or construction of the asset. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Corporation and the cost can be measured reliably. The carrying amount of a replaced asset is derecognized when replaced. A gain or loss arising from the derecognition of an asset is recorded in earnings when the asset is derecognized.

Major overhaul costs are capitalized and depreciated on a straight-line basis to the next major overhaul. Other repair and maintenance costs are charged to earnings during the period in which they are incurred.

The Corporation allocates the amount initially recognized in respect of an item of property, plant and equipment to its significant components and depreciates separately each such component. Residual values, method of depreciation and useful lives of the assets are reviewed annually and adjusted if appropriate.

Interest on the funding attributable to qualifying assets is capitalized during construction and is depreciated as part of the total cost over the useful life of the asset. Capitalized interest is calculated using the effective interest rate method based on specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization commences when borrowing costs and expenditures are incurred at the onset of construction on assets of substantial duration. Interest capitalization ceases when construction of the asset, or part of the asset, is substantially complete.

Depreciation is provided on assets primarily on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress. Depreciation periods for the principal categories of property, plant and equipment are shown in the table below:

	Useful Life	Composite Depreciation Rate
Utility transmission and distribution:		
Electricity transmission equipment	50 to 60 years	2.0%
Electricity distribution equipment	15 to 55 years	3.5%
Gas transmission equipment	15 to 80 years	2.8%
Gas distribution plant and equipment	9 to 54 years	2.8%
Power generation plant and equipment:		
Gas fired	30 to 40 years	3.3%
Coal fired	5 to 40 years	2.5%
Buildings	5 to 60 years	3.5%
Other plant, equipment and machinery	5 to 40 years	3 to 5%

Intangibles

Intangible assets, which consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights, are recorded at cost less accumulated amortization. The assets are amortized on a straight-line basis over their useful lives, which are not longer than 10 years for

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

computer software and between 75 and 100 years for land rights based on the contractual life of the underlying agreements.

Impairment of Property, Plant and Equipment and Intangibles

Property, plant and equipment and intangible assets with finite lives are tested for recoverability whenever events or changes in circumstances indicate a possible impairment. Impairment is assessed and tested at the cash-generating unit (“CGU”) level (or groups of CGUs), which is the smallest identifiable group of assets that generates independent cash inflows. An impairment of property, plant and equipment and intangible assets with finite lives is recognized in earnings when the asset’s carrying value exceeds its recoverable amount. The recoverable amount is the higher of the asset’s fair value less costs to sell and its value in use. Where fair value less costs to sell is not reliably available, value in use is used as the recoverable amount. Value in use is the present value of the future cash flows expected to be derived from an asset, CGU or group of CGUs.

An impairment charge may be reversed only if there is objective evidence that a change in the estimate used to determine the asset’s recoverable amount since the last impairment was recognized is warranted. Where an impairment charge is subsequently reversed, the carrying amount of the asset (or CGU) is increased to the revised recoverable amount to the extent that it does not exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods. A reversal of an impairment charge is recognized immediately in earnings. After such a reversal, the depreciation or amortization charge, where relevant, is adjusted in future periods to allocate the asset’s revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Management necessarily applies judgment in allocating assets that do not generate independent cash flows to appropriate CGUs. The calculations used in determining recoverable amount also involve the use of assumptions as to the price that could be obtained for, or the future cash flows that will be generated by, an asset or group of assets, together with an appropriate discount rate to apply to those cash flows. Subsequent changes to these estimates or judgments may impact the carrying value of the assets within the respective CGU or group of CGUs.

Leases

The Corporation is party to certain arrangements that convey the right to use power generation and non-regulated electric transmission assets and are classified as leases, with the Corporation as the lessor. A lease is classified as a finance lease when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables and are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Finance lease income is recognized in a manner that produces a constant rate of return on the Corporation’s investment in the lease and is included in revenue.

Certain assets under PPAs are classified as operating leases as the Corporation (as lessor) still retains substantially all the risks and rewards of ownership. Assets subject to operating leases are included in property, plant and equipment and are depreciated in a manner consistent with the normal depreciation policy (see property, plant and equipment above). Income from operating leases is recognized in earnings on a straight-line basis over the lease term unless another systematic basis is more representative of the time pattern of the user’s benefit.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Unearned Availability Incentives

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

Consistent with the operating lease classification of the associated PPA assets, these availability incentives are accounted for as part of the minimum lease payments and recognized in earnings on a straight-line basis as lease income. 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 PPA. 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.

Management estimates expected incentives and penalties for operating above or below specified availability targets set out in the PPA. The degree to which incentives are recognized or deferred will change due to revisions to the long-term outlook of plant performance, which is based on historical performance, planned maintenance, reliability and generation availability, and due to revisions in the estimated long term price embedded in the PPA. Where actual results differ from these estimates, the difference will be recognized in the period in which the facts that give rise to the revision become known.

Provisions and Contingencies

The Corporation recognizes provisions when there is a present legal or constructive obligation as a result of a past event and it is probable that an outflow of economic benefits will be required to settle the obligation. If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and, where appropriate, the risks specific to the liability.

The evaluation of the likelihood of the contingent events requires judgment by management as to the probability of exposure to potential loss. Actual results could differ from these estimates.

A contingent asset is not recognized in the consolidated financial statements. However, a contingent asset is disclosed where an inflow of economic benefits is probable.

Asset Retirement Obligations

Asset retirement obligations (“AROs”) are legal and constructive obligations associated with the retirement of tangible long lived assets. These obligations are measured based on discounted future cash flows. Cash flows for AROs are adjusted to take risks and uncertainties into account and are discounted using a pre-tax, risk-free discount rate.

Initially, an ARO is recorded in provisions, with a corresponding increase to property, plant and equipment. Subsequently, the carrying amount of the provision is accreted over the estimated time period until settlement of the obligation, with the accretion expense recognized as interest expense. The asset is depreciated over its estimated useful life. The carrying value is evaluated annually, or more frequently if events or circumstances dictate, taking into account changes in the estimate of future cash flows and a discount rate that reflects the current market assessment of the time value of money.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

AROs have been recorded for the electricity generating plants and the natural gas liquids extraction and processing plants.

Financial Instruments

The Corporation establishes the classification of financial instruments at their initial recognition. Financial assets are classified as held for trading, available for sale, held to maturity or loans and receivables. Financial liabilities are classified as held for trading or other liabilities.

Financial instruments classified as held for trading, other than derivative instruments that are effective hedging instruments, are measured at fair value with changes in fair value recognized in earnings.

Derivatives that are designated as, and continue to be, highly effective cash flow hedging instruments have gains and losses in fair values recognized through other comprehensive income. Derivatives that are designated as fair value hedging instruments have gains and losses recognized in earnings.

Financial instruments classified as available for sale are measured at fair value using quoted prices in an active market. Changes in fair value are recognized in other comprehensive income until the item is derecognized or determined to be impaired, at which time the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. When actively quoted prices are not available, fair value is determined using other valuation techniques. If fair value cannot be reliably estimated, the item is carried at cost.

Financial instruments classified as held to maturity, loans and receivables or other liabilities are measured at fair value upon initial recognition but are subsequently measured at their amortized cost using the effective interest method. Investments in equity instruments that do not have an actively quoted price and whose fair value cannot be reliably measured are measured at cost.

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 time of initial recognition. Transactions costs for long term debt and preferred shares are amortized over the life of the respective financial liability using the effective interest method. The Corporation's long term debt, non-recourse long term debt and preferred shares are presented net of their respective transaction costs.

In estimating fair value, the Corporation utilizes quoted market prices when available. Models incorporating observable market data along with transaction specific factors are also utilized in estimating fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels. The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs)

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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.

Impairment of Financial Instruments

An impairment of loans and receivables or held-to-maturity investments carried at amortised cost is recognized in earnings when the asset's carrying amount exceeds the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. A reduction in an impairment charge may be reversed if the decrease is related to an event occurring after the impairment was recognized.

An impairment of financial assets carried at cost is recognized in earnings when the asset's carrying amount exceeds the present value of estimated future cash flows discounted at the current market rate of return for a similar financial asset. Such impairment losses are not reversed.

When an available for sale financial asset is determined to be impaired, the cumulative gain or loss previously reported in other comprehensive income is recognized in earnings. An impairment charge for an investment in an equity instrument classified as available for sale is not reversed. A reduction in an impairment charge for a debt instrument classified as available for sale may be reversed if the decrease is related to an event occurring after the impairment was recognized.

Where an impairment charge is subsequently reversed, the carrying amount of the asset is increased to the revised recoverable amount to the extent that it does not exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods. A reversal of an impairment charge is recognized immediately in earnings.

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.

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 firm commitment in the case of a foreign currency transaction or a highly probable forecast 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.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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.

Retirement Benefits

The Corporation accrues for its obligations under defined benefit pension and other post employment benefit (“OPEB”) plans. Costs of these benefits are determined using the projected unit credit method and reflect management’s best estimates of investment returns, wage and salary increases, age at retirement and expected health care costs. The assumptions in relation to the expected return on plan assets, estimated benefit obligations, and the cost of providing retirement benefits during the period are set after consultation with qualified actuaries.

Pension plan assets at the balance sheet date are reported at market value. The expected long term rate of return on plan assets is determined at the beginning of the year on the basis of the long bond yield rate at the beginning of the year plus an equity and management premium that reflects the plan asset mix. Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the fair value of plan assets at the beginning of the year and the expected changes in assets due to contributions and benefit payments.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates on high quality corporate bonds that match the timing and amount of expected benefit payments.

For all plans, actuarial gains and losses resulting from differences between actual and expected returns on pension plan assets and changes in assumptions, including the liability discount rate and future salary rates, used to measure the accrued benefit obligations are recognized in other comprehensive income in the period in which they occur.

The cost of retirement benefits for defined benefit pension plans, defined contribution pension plans and OPEB plans is recognized as an expense in salaries, wages and benefits as employees render service. Past service costs are recognized immediately in earnings to the extent that benefits are vested, and otherwise are amortized on a straight-line basis over the period until the benefits are vested. When the services of employees are used in the construction of an asset and the benefits received meet the recognition criteria of an asset, the cost of retirement benefits is included as part of the related property, plant and equipment or intangible asset.

Share Based Compensation Plans

The Corporation expenses stock options. The Corporation determines the fair value of the options on the date of grant using the Black-Scholes option pricing model and recognizes the fair value over the vesting period of the options granted by applying graded vesting, adjusted for estimated forfeitures. The fair value of the options is recorded in salaries, wages and benefits expense and contributed surplus. Contributed surplus is reduced as the options are exercised and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

Share appreciation rights are cash-settled and are measured at fair value using the Black-Scholes option pricing model by applying graded vesting, adjusted for estimated forfeitures. Share appreciation rights are recognized in salaries, wages and benefits expense over the vesting period, with corresponding liabilities recognized in accounts payable and accrued liabilities and other liabilities on the balance sheet. The liability is re-measured at each reporting period.

The option valuation model requires subjective assumptions to be made, including the future volatility of the share price, expected dividend yields, risk-free interest rates and expected staff turnover. Management draws upon a variety of external sources to aid in the determination of the appropriate data to use in such calculations.

Foreign Currency Translation

The consolidated financial statements are presented in Canadian dollars. Each entity within the Corporation determines its own functional currency and items included in the financial statements of each entity are measured accordingly. On consolidation, assets and liabilities of foreign operations are translated into Canadian dollars at the rate of exchange in effect at the balance sheet date and revenues and expenses are translated at the average monthly rates of exchange during the period. Gains or losses on translation are included in accumulated other comprehensive income in share owners' equity.

Transactions that are denominated in foreign currencies are translated at the rate of exchange in effect at the transaction date. Monetary items and non-monetary items that are carried at fair value arising from a transaction denominated in a foreign currency are adjusted to reflect the rate of exchange in effect at the

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

balance sheet date. Gains or losses on translation of such monetary and non-monetary items are recognized in earnings.

Accounting Changes Not Yet Adopted

Certain new or revised standards or interpretations have been issued by the IASB or IFRIC that are not required to be adopted in the current period. The Corporation has not early adopted these standards or interpretations.

IFRS 9 *Financial Instruments*, effective for annual periods beginning on or after January 1, 2013, is part of the IASB's project to replace IAS 39 *Financial Instruments: Recognition and Measurement*. The Corporation is evaluating the potential effect of this new standard.

There are no other standards and interpretations that have been issued, but are not yet effective, that the Corporation anticipates will have a material effect on the consolidated financial statements once adopted.

3. FIRST-TIME ADOPTION OF IFRS

The Corporation's consolidated financial statements for the year ended December 31, 2011 will be the first annual financial statements that comply with IFRS. These interim financial statements have been prepared as described in Note 2, including the application of IFRS 1 *First-time Adoption of International Financial Reporting Standards*, with a date of transition of January 1, 2010 ("Transition Date").

The following tables reconcile the financial statements previously reported under Canadian GAAP to the financial statements prepared in accordance with IFRS. Explanations of the effect of the transition to IFRS follow the reconciliations.

3. FIRST-TIME ADOPTION OF IFRS (continued)

Reconciliation of the Consolidated Balance Sheet as at January 1, 2010 (Transition Date)

Canadian Utilities Limited
As at January 1, 2010
(Millions of Canadian Dollars)

	Notes	Canadian GAAP	Effect of Transition to IFRS	IFRS
ASSETS				
Current assets				
Accounts receivable	k	\$ 366	\$ (12)	\$ 354
Finance lease receivables	l	1	7	8
Deferred income tax asset	o	7	(7)	-
Regulatory assets	k	37	(37)	-
Other current assets	m	917	8	925
		1,328	(41)	1,287
Property, plant and equipment	d,e,g,l,m,n	6,733	293	7,026
Investment in ATCO Structures & Logistics		122	(2)	120
Finance lease receivables	l	58	287	345
Regulatory assets	k	384	(384)	-
Retirement benefit assets	f	142	(142)	-
Other assets	m	317	(33)	284
Total assets		\$9,084	\$ (22)	\$9,062
LIABILITIES AND SHARE OWNERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	k	\$ 382	\$ 12	\$ 394
Regulatory liabilities	k	26	(26)	-
Long term debt	p	3	125	128
Other current liabilities		52	15	67
		463	126	589
Deferred income tax liabilities	d,e,g,l,m	478	(123)	355
Regulatory liabilities	k	571	(571)	-
Provisions	g,q	-	97	97
Retirement benefit obligations	f	64	(6)	58
Other liabilities	m,n	575	771	1,346
Long term debt	p	3,102	(125)	2,977
Total liabilities		5,253	169	5,422
Equity				
Equity preferred shares	r	510	(5)	505
Equity preferred shares of subsidiary corporation	r	275	(5)	270
Class A and Class B share owners' equity				
Class A and Class B shares		528	-	528
Contributed surplus		3	-	3
Retained earnings	d,e,f,g,h,k,l,m	2,569	(232)	2,337
Accumulated other comprehensive income	h	(54)	51	(3)
Total equity		3,831	(191)	3,640
Total liabilities and equity		\$9,084	\$ (22)	\$9,062

3. FIRST-TIME ADOPTION OF IFRS (continued)

Reconciliation of the Consolidated Balance Sheet as at December 31, 2010

Canadian Utilities Limited
As at December 31, 2010
(Millions of Canadian Dollars)

	Notes	Canadian GAAP	Effect of Transition to IFRS	IFRS
ASSETS				
Current assets				
Accounts receivable	k	\$ 405	\$ (49)	\$ 356
Finance lease receivables	l	3	8	11
Deferred income tax asset	o	2	(2)	-
Regulatory assets	k	17	(17)	-
Other current assets	m	655	17	672
		1,082	(43)	1,039
Property, plant and equipment	d,e,g,l,m,n	7,036	321	7,357
Investment in ATCO Structures & Logistics		138	(1)	137
Finance lease receivables	l	197	282	479
Regulatory assets	k	461	(461)	-
Retirement benefit assets	f	186	(186)	-
Other assets	m	315	(10)	305
Total assets		\$9,415	\$ (98)	\$9,317
LIABILITIES AND SHARE OWNERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities	k	\$ 405	\$ 1	\$ 406
Regulatory liabilities	k	17	(17)	-
Long term debt	p	3	100	103
Other current liabilities		42	18	60
		467	102	569
Deferred income tax liabilities	d,e,g,l,m	541	(167)	374
Regulatory liabilities	k	666	(666)	-
Provisions	g,q	-	112	112
Retirement benefit obligations	f	70	212	282
Other liabilities	m,n	476	827	1,303
Long term debt	p	3,060	(100)	2,960
Total liabilities		5,280	320	5,600
Equity				
Equity preferred shares	r	510	(5)	505
Equity preferred shares of subsidiary corporation	r	350	(7)	343
Class A and Class B share owners' equity				
Class A and Class B shares		533	-	533
Contributed surplus		1	-	1
Retained earnings	d,e,f,g,h,k,l,m	2,808	(463)	2,345
Accumulated other comprehensive income	h	(67)	57	(10)
Total equity		4,135	(418)	3,717
Total liabilities and equity		\$9,415	\$ (98)	\$9,317

3. FIRST-TIME ADOPTION OF IFRS (continued)

Reconciliation of the Consolidated Statement of Earnings for the Three Months Ended March 31, 2010

Canadian Utilities Limited
Three Months Ended March 31, 2010
(Millions of Canadian Dollars)

	Notes	Canadian GAAP	Effect of Transition to IFRS	IFRS
Revenues	l,n	\$749	\$10	\$759
Costs and expenses				
Natural gas supply	s	7	(7)	-
Purchased power		15	-	15
Operation and maintenance	s	284	(284)	-
Selling and administrative	s	52	(52)	-
Depreciation and amortization	d,e,l,m,n	83	(1)	82
Interest	s,t	61	(61)	-
Franchise fees		61	-	61
Salaries, wages and benefits	f,s	-	79	79
Energy transmission and transportation	s	-	2	2
Plant and equipment maintenance	m,s	-	28	28
Fuel costs	s	-	76	76
Materials and consumables	s	-	77	77
Other	s	-	75	75
		563	(68)	495
		186	78	264
Earnings from investment in ATCO Structures & Logistics		5	-	5
Other income (expense)		5	(6)	(1)
Operating profit		196	72	268
Interest income	s	-	-	-
Interest expense	s	-	58	58
Net finance costs	t	-	58	58
Earnings before income taxes		196	14	210
Income taxes	d	37	18	55
Earnings for the period		\$159	\$ (4)	\$155

3. FIRST-TIME ADOPTION OF IFRS (continued)

Reconciliation of the Consolidated Statement of Earnings for the Year Ended December 31, 2010

Canadian Utilities Limited
Year Ended December 31, 2010
(Millions of Canadian Dollars)

	Notes	Canadian GAAP	Effect of Transition to IFRS	IFRS
Revenues	l,n	\$2,657	\$42	\$2,699
Costs and expenses				
Natural gas supply	s	89	(89)	-
Purchased power		54	-	54
Operation and maintenance	s	975	(975)	-
Selling and administrative	s	267	(267)	-
Depreciation and amortization	d,e,l,m,n	335	7	342
Interest	s,t	236	(236)	-
Franchise fees		173	-	173
Salaries, wages and benefits	f,s	-	381	381
Energy transmission and transportation	s	-	13	13
Plant and equipment maintenance	m,s	-	168	168
Fuel costs	s	-	310	310
Materials and consumables	s	-	177	177
Other	s	-	284	284
		2,129	(227)	1,902
		528	269	797
Earnings from investment in ATCO Structures & Logistics		20	-	20
Other income (expense)		39	(40)	(1)
Operating profit		587	229	816
Interest income	s	-	18	18
Interest expense	s	-	222	222
Net finance costs	t	-	204	204
Earnings before income taxes		587	25	612
Income taxes	d	109	52	161
Earnings for the period		\$ 478	\$ (27)	\$ 451

3. FIRST-TIME ADOPTION OF IFRS (continued)

Reconciliations of the Consolidated Statement of Changes in Equity as at January 1, 2010, March 31, 2010 and December 31, 2010

	March 31, 2010	December 31, 2010	January 1, 2010
Equity under Canadian GAAP	\$3,903	\$4,135	\$3,831
IFRS adjustments increase (decrease):			
Fair value as deemed cost for certain items of property, plant and equipment	(118)	(114)	(125)
Retirement benefits – actuarial gains and losses	(163)	(294)	(103)
Assets and liabilities from rate regulated activities	128	105	138
Lease accounting treatment for certain power generation assets	(11)	(8)	(12)
Asset retirement obligations	(19)	(25)	(19)
Rate regulated property, plant and equipment	(75)	(75)	(75)
Major overhauls	(5)	(7)	(5)
Other	8	-	10
Equity under IFRS	\$3,648	\$3,717	\$3,640

Reconciliations of Comprehensive Income for the Three Months Ended March 31, 2010 and the Year Ended December 31, 2010

	Three Months Ended March 31, 2010	Year Ended December 31, 2010
Comprehensive income under Canadian GAAP	\$ 123	\$ 422
Increase (decrease) in earnings for the period:		
Depreciation on revaluation of certain items of property, plant and equipment	2	7
Retirement benefits – amortization of actuarial gains and losses	5	12
Assets and liabilities from rate regulated activities	(9)	(31)
Lease accounting treatment for certain power generation assets	2	5
Asset retirement obligations	1	(7)
Major overhauls	-	(2)
Share based compensation	-	1
Other	7	31
	8	16
Increase (decrease) in other comprehensive income for the period:		
Retirement benefits – actuarial gains and losses	(65)	(203)
Other	4	6
	(61)	(197)
Comprehensive income under IFRS	\$ 70	\$ 241

3. FIRST-TIME ADOPTION OF IFRS (continued)

Reconciliations of Cash Flows for the Three Months Ended March 31, 2010 and the Year Ended December 31, 2010

	Three Months Ended March 31, 2010		
	Canadian GAAP	Effect of Transition	IFRS
Cash flow from operations	\$ 296	\$ 69	\$ 365
Cash flow from investing activities	(181)	(22)	(203)
Cash flow from financing activities	(61)	(47)	(108)
Foreign currency translation	(13)	-	(13)

	Year Ended December 31, 2010		
	Canadian GAAP	Effect of Transition	IFRS
Cash flow from operations	\$ 764	\$ 338	\$ 1,102
Cash flow from investing activities	(777)	(69)	(846)
Cash flow from financing activities	(232)	(269)	(501)
Foreign currency translation	(11)	-	(11)

The changes in classifications of cash flows under IFRS are mainly due to:

- Separate presentation of interest paid of \$37 million for the three months ended March 31, 2010 and \$223 million for the year ended December 31, 2010 in financing activities as required by IFRS. Canadian GAAP only required interest paid to be disclosed in the notes to the financial statements.
- Reclassification of contributions by utility customers for extensions to plant from investing activities to operating activities of \$19 million and \$66 million for the three months ended March 31, 2010 and the year ended December 31, 2010, respectively. Under IFRS, the Corporation treats customer contributions as deferred revenue and classifies the associated cash flows as operating activities. Under Canadian GAAP, customer contributions were treated as a reduction of property, plant and equipment and classified the cash flows as investing activities

Explanations of the Effect of the Transition to IFRS

The following explanations accompany the preceding reconciliations and describe the effect of the transition to IFRS, including: mandatory exceptions and optional exemptions from retrospective application of IFRS under IFRS 1 and items requiring retrospective application.

3. FIRST-TIME ADOPTION OF IFRS (continued)

Mandatory Exceptions From Retrospective Application

IFRS 1 requires certain mandatory exceptions from full retrospective application of all accounting standards effective at the reporting date. The following mandatory exceptions were applicable to the Corporation at the Transition Date:

a) Non-Controlling Interests

Total comprehensive income is attributed to the owners of the parent and to the non-controlling interests prospectively.

b) Hedge Accounting

Hedge accounting can only be applied prospectively from the Transition Date to transactions that satisfy the hedge accounting criteria at that date. Hedging relationships cannot be designated retrospectively and the supporting documentation cannot be created retrospectively. This exception did not result in change for the Corporation.

c) Estimates

The Corporation followed the mandatory exception and did not use hindsight to create or revise estimates. The estimates previously made by the Corporation under Canadian GAAP were not revised for IFRS, except to reflect any difference in accounting policies.

Optional IFRS 1 Exemptions From Retrospective Application

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. IFRS 1 gives limited optional exemptions from retrospectively applying the standards where the costs of doing so would likely exceed the benefits to users of the financial statements. Significant IFRS 1 exemptions used by the Corporation are as follows:

d) Fair Value as Deemed Cost

IFRS 1 allows an entity to measure items of property, plant and equipment at fair value at the date of transition to IFRS and to deem the fair value as cost. The Corporation elected to reduce the carrying value of certain items of property, plant and equipment, primarily power generation assets, to fair value at the Transition Date, and used that fair value as the deemed cost of those assets at that date. A revaluation of these assets was not required under Canadian GAAP. Adopting this exemption reduced property, plant and equipment by \$169 million, deferred income tax liabilities by \$44 million and retained earnings by \$125 million. As a result of this change, depreciation and amortization decreased by \$3 million and \$9 million for the three months ended March 31, 2010 and the year ended December 31, 2010, respectively.

3. FIRST-TIME ADOPTION OF IFRS (continued)

e) Rate Regulated Property, Plant and Equipment

For operations subject to rate regulation, other than the regulated generating plants owned by ATCO Power, the Corporation has used the carrying amount of property, plant and equipment determined under Canadian GAAP as deemed cost on transition to IFRS. The carrying amount of these assets as they are included in rate base and applying IFRS retrospectively would have been onerous.

For the regulated generating plants owned by ATCO Power that are governed by PPAs, the Corporation reduced property, plant and equipment by \$102 million, deferred income tax liabilities by \$27 million and retained earnings by \$75 million for costs that cannot be capitalized under IFRS. As a result of this change, depreciation and amortization decreased by \$3 million and \$10 million and plant and equipment maintenance increased by \$2 million and \$10 million for the three months ended March 31, 2010 and the year ended December 31, 2010 respectively.

f) Retirement Benefits

At the Transition Date, rather than continue to amortize the cumulative actuarial gains and losses, the Corporation elected to charge all cumulative unamortized actuarial gains and losses for all defined benefit pension and OPEB plans to retained earnings.

The adoption of IFRS reduced retirement benefit assets by \$142 million, retirement benefit liabilities by \$6 million, deferred income tax liabilities by \$34 million and retained earnings by \$103 million at the Transition Date. As a result of this change, salaries, wages and benefits expense decreased by \$7 million and \$16 million for the three months ended March 31, 2010 and the year ended December 31, 2010, respectively.

Actuarial gains and losses incurred during the three months ended March 31, 2010 and the year ended December 31, 2010 have been recognized in other comprehensive income.

g) Asset Retirement Obligations

The Corporation elected to use an exemption allowing ARO liabilities and related assets to be re-measured on a simplified approach at the Transition Date rather than perform full detailed ARO calculations.

At the Transition Date, the re-measurement increased ARO liabilities by \$19 million and reduced property plant and equipment by \$7 million, deferred income tax liabilities by \$7 million and retained earnings by \$19 million. The ARO liabilities have been reclassified from other liabilities to provisions on the consolidated balance sheet.

h) Cumulative Translation Differences

The Corporation elected to recognize all cumulative translation gains and losses included in accumulated other comprehensive income in opening retained earnings at the Transition Date. As a result, accumulated other comprehensive income increased by \$51 million and retained earnings decreased by \$51 million.

3. FIRST-TIME ADOPTION OF IFRS (continued)

i) Business Combinations

The Corporation elected to take the exemption to not restate business combinations that occurred before the Transition Date. Any goodwill arising on such business combinations before the Transition Date was not adjusted from the carrying value previously determined under Canadian GAAP.

j) Share Based Payment Transactions

The Corporation elected to apply the IFRS requirements only to equity instruments granted after November 7, 2002 that had not vested as of the Transition Date, and to all liabilities arising from share based payment transactions that existed at the Transition Date.

Retrospective Treatments on Transition

In the absence of an IFRS 1 exemption, IFRS requires retrospective application at the Transition Date. The Corporation applied retrospective treatment to the following items at the Transition Date.

k) Assets and Liabilities from Rate Regulated Activities

At the Transition Date, the Corporation derecognized all assets and liabilities relating to rate regulated activities. This change reduced total assets by \$442 million, total liabilities by \$580 million, and increased retained earnings by \$143 million. Refer to Note 4 for information regarding the effect on earnings.

l) Leases

Certain power generation assets as well as certain electric transmission assets that were exempt from lease treatment under Canadian GAAP have been reclassified from property, plant and equipment to finance lease receivables under IFRS. These assets were grandfathered under the Canadian GAAP guidelines and did not need to be recognized as leases. At the Transition Date, this change increased finance lease receivables by \$294 million and reduced property, plant and equipment by \$310 million, deferred income taxes by \$4 million and retained earnings by \$12 million. In addition, depreciation and amortization expense decreased by \$4 million and \$14 million, and revenues decreased by \$2 million and \$7 million, for the three months ended March 31, 2010 and the year ended December 31, 2010, respectively.

m) Major Overhauls

Under IFRS, major overhaul expenses are capitalized when incurred and depreciated until the next overhaul. Overhaul costs that do not relate to the replacement of components or the installation of new assets are expensed when incurred. Under Canadian GAAP, costs of major overhauls that are included in long term service agreements as variable costs over and above fixed costs were expensed in equal proportions over the life of the agreement. At the Transition Date, this change increased total assets by \$7 million and total liabilities by \$11 million and increased retained earnings by \$5 million. As a result of this change, earnings decreased \$1 million and \$2 million for the three months ended March 31, 2010 and the year ended December 31, 2010, respectively.

3. FIRST-TIME ADOPTION OF IFRS (continued)

Reclassifications

The following reclassifications were made due to differences in presentation between Canadian GAAP and IFRS:

n) Customer Contributions

Under IFRS, customer contributions for the acquisition or construction of property, plant and equipment are consideration for a future service and therefore considered to be deferred revenues to be amortized over the period in which the service is provided.

Under Canadian GAAP, these customer contributions netted against property, plant and equipment and were amortized on the same basis as, and offset against the depreciation charge of, the assets to which they related.

At the Transition Date, property, plant and equipment and other liabilities increased by \$887 million. Revenues and depreciation and amortization expense increased by \$8 million and \$32 million in the three months ended March 31, 2010 and the year ended December 31, 2010, respectively.

o) Deferred Income Taxes

IFRS does not permit deferred tax assets or liabilities as current assets or liabilities. As a result, current deferred income tax assets of \$7 million as at the Transition Date and \$2 million as at December 31, 2010, were reclassified to non-current deferred income tax assets on the consolidated balance sheet.

p) Long Term Debt Due Within One Year

Long term debt due within one year that under Canadian GAAP was classified as long term due to the ability and intention to refinance must be disclosed as a current liability under IFRS. IFRS does not contain the same guidelines allowing long term debt that is to be refinanced to be shown as non-current. Consequently, long term debt of \$125 million at the Transition Date and \$100 million at December 31, 2010 have been re-classified to current liabilities on the consolidated balance sheet.

q) Provisions

Provisions of \$82 million as at the Transition Date and \$87 million as at December 31, 2010 that were previously included in deferred credits have been separately disclosed as provisions on the consolidated balance sheet as required by IFRS.

r) Equity Preferred Shares

Under IFRS, equity preferred shares are presented as components of equity separate from the parent share owners' equity. Under Canadian GAAP, equity preferred shares were presented as equity preferred shares outside of share owners' equity. Equity preferred shares of \$750 million as at the Transition Date and \$860 million as at December 31, 2010 have been included in the total equity section of the consolidated balance sheet.

3. FIRST-TIME ADOPTION OF IFRS (continued)

s) Nature of Expenses

IFRS requires expenses to be classified on the statement of earnings by either nature or function, not as a combination of both. If classified by function, the classification by nature is required to be disclosed in the notes to the financial statements. Therefore, the Corporation has elected to present costs and expenses on the consolidated statement of earnings solely by nature. Under Canadian GAAP, the Corporation presented costs and expenses in a combination of both nature and function. As a result, operation and maintenance and selling and administrative expenses were reclassified to separate categories by nature as identified in the consolidated statement of earnings.

t) Net Finance Costs

Under IFRS, interest income and expense are presented in the consolidated statement of earnings as net finance costs below operating profit.

4. SEGMENTED INFORMATION

Segmented Results – Three Months Ended March 31

Starting in the first quarter of 2011, the results of operations and financial position of the Corporation's energy, power generation and infrastructure business in Australia are reported in a separate segment called ATCO Australia. This new segment includes the Corporation's interests in three existing power generation plants located in Australia, which were previously reported in the Energy Segment. Comparative figures for the Energy Segment have been restated to confirm to the current presentation.

2011 2010	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations	Consolidated
Revenues – external	\$ 468 \$ 425	\$ 298 \$ 235	\$ 24 \$ 81	\$ 19 \$ 18	\$ - \$ -	\$ 809 \$ 759
Revenues – intersegment ⁽¹⁾	6 6	2 3	- -	31 30	(39) (39)	- -
Revenues	\$ 474 \$ 431	\$ 300 \$ 238	\$ 24 \$ 81	\$ 50 \$ 48	\$ (39) \$ (39)	\$ 809 \$ 759
Adjusted Earnings	\$ 101 \$ 97	\$ 54 \$ 37	\$ 4 \$ 5	\$ 7 \$ 13	\$ - \$ 2	\$ 166 \$ 154
Total assets ⁽²⁾	\$6,944 \$6,825	\$1,893 \$1,743	\$ 227 \$ 260	\$ 745 \$ 581	\$(155) \$ (92)	\$ 9,654 \$ 9,317

⁽¹⁾ Intersegment revenues are recognized on the basis of prevailing market or regulated prices.

⁽²⁾ 2010 comparative total assets are as at December 31, 2010.

4. SEGMENTED INFORMATION (continued)

Reconciliation of Adjusted Earnings and Earnings Attributable to Class A and Class B Shares

2011 2010	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations	Consolidated
Adjusted Earnings	\$ 101	\$ 54	\$ 4	\$ 7	\$ -	\$ 166
	\$ 97	\$ 37	\$ 5	\$ 13	\$ 2	\$ 154
Adjustments for rate regulated activities	3	-	-	-	1	4
	(10)	-	-	-	1	(9)
Adjustment for dividends on equity preferred shares	-	-	-	6	-	6
	-	-	-	5	-	5
Earnings attributable to Class A and Class B shares	\$ 104	\$ 54	\$ 4	\$ 13	\$ 1	\$ 176
	\$ 87	\$ 37	\$ 5	\$ 18	\$ 3	\$ 150
Earnings attributable to equity preferred share owners of subsidiary						6
						5
						\$ 182
Earnings for the period						\$ 155

Adjusted Earnings

Adjusted Earnings are defined as earnings attributable to Class A and Class B shares after adjusting for the timing of revenues and expenses associated with rate regulated activities and dividends on equity preferred shares charged to retained earnings as well as one-time gains and losses and items that are not in the normal course of business or a result of day to day operations. Adjusted Earnings are a key measure of segment earnings used by the Chief Operating Decision Maker (“CODM”) for purposes of assessing segment performance and allocating resources. Other accounts in the consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

With respect to the accounting for rate regulated activities, prior to the adoption of IFRS, the Corporation had, as permitted by Canadian GAAP, utilized standards issued by the Financial Accounting Standards Board (“FASB”) in the United States (“U.S.”) as another source of GAAP. The FASB standards provided guidance on the recognition and measurement of assets and liabilities arising from rate regulation where Canadian GAAP no longer provided such guidance. Adjusted Earnings will present earnings from rate regulated activities on the same basis as was used prior to adopting IFRS.

There is currently no specific guidance under IFRS for rate regulated entities. Consequently, the Corporation does not recognize assets and liabilities from rate regulated activities under IFRS.

While the accounting for rate regulated activities has changed, the economics of rate regulation have not changed (see Nature and Economic Effects of Rate Regulation in Note 2). The CODM is of the belief that earnings adjusted in accordance with the FASB standards are a better representation of the results of operations of its rate regulated activities. Furthermore, Adjusted Earnings will facilitate comparability of the Corporation’s financial results with rate regulated peer companies that have deferred the adoption of IFRS by one year to 2012 as permitted by the Canadian Accounting Standards Board, as well as with entities that utilize U.S. accounting principles for rate regulated entities.

4. SEGMENTED INFORMATION (continued)

Rate regulated accounting under Canadian GAAP differs from IFRS in the following ways:

Canadian GAAP Treatment	IFRS Treatment
(1) The Corporation was able to defer the recognition of cash received in advance of future expenditures.	The Corporation records revenues when amounts are billed to customers, but does not recognize the associated costs until they are incurred.
(2) The Corporation was able to recognize revenues associated with recoverable costs in advance of future billings to customers.	The Corporation records costs when incurred, but does not recognize their recovery until changes to customer rates are reflected in future customer billings.
(3) The Corporation recognized the earnings that arose from a regulatory decision that pertained to current and prior periods upon receipt of the decision.	The Corporation recognizes earnings when customer rates are changed and amounts are billed to customers.
(4) Intercompany profits on the manufacture or construction of facilities for a regulated public utility in the consolidated group were deemed to have been realized to the extent that the transfer price on such facilities was recognized for rate-making purposes by a regulator.	Intercompany profits are eliminated upon consolidation. The Corporation then recognizes those profits in earnings as amounts are billed to customers over the life of the related asset.

4. SEGMENTED INFORMATION (continued)

Timing adjustments for rate regulated activities are as follows:

	Three Months Ended March 31	
	2011	2010
<i>Additional revenues billed in current period:</i>		
Future removal and site restoration costs ⁽¹⁾	\$ 12	\$ 11
Retirement benefits ⁽²⁾	7	2
Transmission and distribution system load balancing ⁽⁵⁾	-	5
Impact of colder temperatures on revenues ⁽⁶⁾	9	-
Other	6	7
	34	25
<i>Revenues to be billed in future period:</i>		
Deferred income taxes ⁽³⁾	(12)	(14)
Transmission access payments ⁽⁴⁾	(4)	-
Transmission and distribution system load balancing ⁽⁵⁾	(6)	-
Impact of warmer temperatures on revenues ⁽⁶⁾	-	(6)
Other	(1)	(4)
	(23)	(24)
<i>Regulatory decisions:</i>		
Decisions related to current and prior periods ⁽⁷⁾	(6)	(9)
<i>Intercompany profits:</i>		
Intercompany profits related to construction of property, plant and equipment and intangibles ⁽⁸⁾	(1)	(1)
	\$ 4	\$ (9)

Descriptions of the adjustments and the timing of recovery or refund for each are as follows:

Description	Timing of Recovery or Refund
⁽¹⁾ Forecast future removal and site restoration costs are billed to customers over the life of the associated assets in advance of future expenditures.	Revenues are recorded when forecast costs are billed to customers. Costs will be expensed in future periods when incurred.
⁽²⁾ The Corporation accrues for its obligations under defined benefit pension plans and other post employment benefit plans, whereas the costs of retirement benefits are recovered from customers when paid.	Variances between the amounts paid and accrued for the retirement benefit plans will vary depending on the performance of plan assets and the actuarial valuations of plan obligations. These variances will remain until the plans are paid, settled or terminated.
⁽³⁾ Deferred income taxes are a non-cash expense incurred by the Corporation related to temporary differences between the book value and the tax value of assets and liabilities.	Deferred income taxes are not recovered from customers until the temporary differences reverse and current income taxes are paid by the utilities.

4. SEGMENTED INFORMATION (continued)

Description	Timing of Recovery or Refund
<p>(4) ATCO Electric expenses transmission access payments when incurred, whereas the amount included in customer rates is based on forecast cost. Actual payments may vary from forecast due to changes in tariffs charged by the Alberta Electric System Operator (“AESO”).</p>	<p>Recoveries from or refunds to customers of differences between transmission access payments billed to customers and paid by ATCO Electric are expected to occur in the following year.</p>
<p>For major transmission capital projects in Alberta, ATCO Electric’s revenues include a return on forecast rate base. When actual capital costs vary from forecast capital costs, variances may arise between the returns on forecast versus actual rate base.</p>	<p>Recoveries from or refunds to the AESO of variances between forecast and actual returns on rate base are expected to occur in the following year.</p>
<p>Variances between ATCO Electric’s actual and forecast income tax expense may arise due to changes in enacted and substantively enacted tax rates. The amount included in customer rates is based on forecast tax rates.</p>	<p>Recoveries from or refunds to customers of variances between forecast and actual income taxes arising from changes in enacted or substantively enacted tax rates are expected to occur in the following year.</p>
<p>(5) ATCO Gas and ATCO Pipelines engage in the purchase or sale of natural gas to maintain appropriate operating pressures on their distribution and transmission pipeline systems. The purchases and sales of natural gas are recorded as expenses and revenues, respectively, when incurred.</p>	<p>The utilities may apply to the AUC for recoveries from or refunds to customers of the net purchases and sales when they exceed certain thresholds: for ATCO Gas, \$5 million over six successive months or \$10 million for one month for either of its North or South systems; for ATCO Pipelines, \$7 million for its North system and \$5 million for its South system.</p>
<p>(6) ATCO Gas’ customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below the norm are refunded to or recovered from customers in future periods.</p>	<p>ATCO Gas may apply to the AUC for recoveries from or refunds to customers when the net revenue variances exceed \$7 million at April 30th of any year for either of its North or South systems.</p>

4. SEGMENTED INFORMATION (continued)

Description	Timing of Recovery or Refund
<p>(7) The utilities recognize revenues from regulatory decisions when customer rates are changed and amounts are billed to customers. Under Canadian GAAP, the utilities recognized the earnings that affected current and prior periods upon receipt of the decision.</p>	<p>In the first quarter of 2010, ATCO Gas recorded earnings of \$11 million for the partial recovery from customers of amounts previously paid to customers in regard to the Carbon storage facility. Under IFRS, these earnings will be recognized over a period of 8 months commencing in the second quarter of 2010. In the third quarter of 2010, ATCO Gas recorded an additional \$14 million of earnings pertaining to Carbon. Under IFRS, these earnings will be recognized over a period of 14 months commencing in the fourth quarter of 2010.</p> <p>In the first quarter of 2010, ATCO Gas recorded a contingent liability regarding amounts previously recovered from customers for historical transportation imbalances which reduced its earnings by \$8 million. The AUC's final decision resulted in a reversal of \$1 million of the contingent liability in the third quarter of 2010. Under IFRS, the net \$7 million reduction in earnings was recorded in the fourth quarter of 2010 when it was refunded to customers.</p> <p>In 2007, ATCO Electric was directed to refund to customers the federal deferred income taxes previously recovered from customers. A portion of the total liability to customers was to be refunded over a five year period commencing in 2008. Under IFRS, revenues are reduced when the refund occurs. Consequently, earnings in 2010 were reduced by \$2 million and the remaining amount of \$2 million is expected to be refunded in 2011.</p>
<p>(8) Intercompany profits included in property, plant and equipment and computer software by the utilities is eliminated upon consolidation.</p>	<p>The Corporation will recognize those intercompany profits in earnings as amounts are billed to customers over the life of the related asset.</p>

5. TRANSFER OF ATCO RESOURCES

On January 1, 2011, ATCO Ltd., the Corporation's parent, transferred its wholly owned subsidiary, ATCO Resources, to ATCO Power, a wholly owned subsidiary of the Corporation. The fair value of the common shares of ATCO Resources, net of its existing debt obligations, was \$82.5 million, as estimated by an independent financial advisor and supported by management.

ATCO Ltd. transferred its common shares of ATCO Resources to the Corporation in exchange for 1,059,658 Class A non-voting shares and 489,171 Class B common shares of the Corporation, having a value of \$82.5 million. This is a related party transaction between entities under common control and was measured at the carrying amount. The excess of the fair value of the shares and the carrying value of the investment was recorded in equity.

6. DIVIDENDS

Cash dividends declared and paid per share for all series and classes of preferred and common shares are as follows:

	Three Months Ended March 31	
	2011	2010
<i>Equity preferred shares:</i>		
5.8% Cumulative Redeemable Second Preferred Shares, Series W	\$0.362500	\$0.362500
6.0% Cumulative Redeemable Second Preferred Shares, Series X	0.375000	0.375000
4.35% Perpetual Cumulative Second Preferred Shares, Series O	0.271875	0.271875
4.35% Perpetual Cumulative Second Preferred Shares, Series T	0.271875	0.271875
4.35% Perpetual Cumulative Second Preferred Shares, Series U	0.271875	0.271875
4.70% Perpetual Cumulative Second Preferred Shares, Series V	0.271875	0.271875
Class A and Class B shares	\$0.4025	\$0.3775

It is the policy of the Corporation to pay dividends quarterly on its Class A and Class B Shares. The matter of an increase in the quarterly dividend is addressed by the Board of Directors in the first quarter of each year. The payment of any dividend is at the discretion of the Board of Directors and depends on the financial condition of the Corporation and other factors.

7. PROPERTY, PLANT AND EQUIPMENT

	Utility Transmission & Distribution	Power Generation	Land and buildings	Construction Work-in- Progress	Other	Total
<i>Cost:</i>						
At January 1, 2010 <i>(as restated)</i>	\$7,290	\$1,876	\$259	\$ 377	\$872	\$10,674
Additions	641	28	30	53	54	806
Disposals	(83)	(5)	(1)	-	(41)	(130)
Transfers	-	-	-	(134)	-	(134)
Foreign exchange adjustment	-	-	-	9	-	9
At December 31, 2010	7,848	1,899	288	305	885	11,225
Additions	86	8	1	103	-	198
Transfer of ATCO Resources	-	126	-	-	-	126
Disposals	(3)	(2)	-	-	(4)	(9)
Foreign exchange adjustment	-	(1)	-	-	-	(1)
At March 31, 2011	\$7,931	\$2,030	\$289	\$ 408	\$881	\$11,539
<i>Accumulated depreciation:</i>						
At January 1, 2010 <i>(as restated)</i>	\$2,116	\$ 945	\$ 76	\$ -	\$511	\$ 3,648
Depreciation	198	64	7	-	20	289
Disposals	(56)	-	(1)	-	(12)	(69)
Foreign exchange adjustment	-	-	-	-	-	-
At December 31, 2010	2,258	1,009	82	-	519	3,868
Depreciation	51	17	2	-	8	78
Transfer of ATCO Resources	-	39	-	-	-	39
Disposals	(3)	(2)	-	-	(4)	(9)
Foreign exchange adjustment	-	-	-	-	-	-
At March 31, 2011	\$2,306	\$1,063	\$ 84	\$ -	\$523	\$ 3,976
<i>Net book value:</i>						
At January 1, 2010 <i>(as restated)</i>	\$5,174	\$ 931	\$183	\$377	\$361	\$ 7,026
At December 31, 2010	\$5,590	\$ 890	\$206	\$305	\$366	\$ 7,357
At March 31, 2011	\$5,625	\$ 967	\$205	\$408	\$358	\$ 7,563

8. LEASES

Finance Leases

The total net investment in finance leases (with the Corporation as the lessor) is shown below. Earnings from these agreements are recognized in revenue.

	March 31, 2011	December 31, 2010
<i>Net investment in finance leases:</i>		
Finance lease - gross investment	\$ 1,239	\$ 1,128
Unearned finance income	(691)	(638)
	\$ 548	\$ 490
<hr/>		
Current portion	\$ 13	\$ 11
Non-current portion	535	479
	\$ 548	\$ 490
<hr/>		
<i>Gross receivables from finance leases:</i>		
In one year or less	\$ 72	\$ 64
In more than one year, but not more than five years	313	318
In more than five years	854	746
	\$ 1,239	\$ 1,128
<hr/>		
<i>Net investment in finance leases:</i>		
In one year or less	\$ 13	\$ 11
In more than one year, but not more than five years	81	77
In more than five years	454	402
	\$ 548	\$ 490
<hr/>		

9. CLASS A AND CLASS B SHARES AND EARNINGS PER SHARE

There were 87,072,150 (2010 – 85,826,964) Class A non-voting shares and 40,409,949 (2010 – 40,015,106) Class B common shares outstanding on March 31, 2011. In addition, there were 737,550 options to purchase Class A non-voting shares outstanding at March 31, 2011 under the Corporation's stock option plan. From April 1, 2011, to April 27, 2011, no stock options were granted or cancelled, 5,000 stock options were exercised, 2,300 Class B common shares were converted to Class A non-voting shares and no Class A non-voting shares were purchased under the Corporation's normal course issuer bid.

The earnings and average number of shares used to calculate earnings per share are as follows:

	Three Months Ended March 31	
	2011	2010
Weighted average shares outstanding	127,466,347	125,861,010
Effect of dilutive stock options	170,849	187,076
Weighted average dilutive shares outstanding	127,637,196	126,048,086
<i>Earnings for earnings per share calculation:</i>		
Earnings for the period	\$182	\$155
Dividends on equity preferred shares	12	11
	\$170	\$144
<i>Earnings and diluted earnings per Class A and Class B share:</i>		
Earnings per Class A and Class B share	\$1.34	\$1.14
Diluted earnings per Class A and Class B share	\$1.33	\$1.14

Normal course issuer bid

On March 1, 2011, Canadian Utilities Limited commenced a new normal course issuer bid for the purchase of up to 3% of the outstanding Class A non-voting shares. The bid will expire on February 29, 2012. From March 1, 2011 to April 27, 2011, 4,000 shares have been purchased.

10. CAPITAL DISCLOSURES

The Corporation's key measures of capital structure are as follows:

	March 31, 2011	December 31, 2010	January 1, 2010
Class A and Class B shares	\$ 616	\$ 533	\$ 528
Contributed surplus	-	1	3
Retained earnings	2,447	2,345	2,337
Accumulated other comprehensive income	(10)	(10)	(3)
Equity preferred shares	848	848	775
Total equity	3,901	3,717	3,640
Long term debt	3,061	3,063	3,105
Non-recourse long term debt	415	341	404
Total debt	3,476	3,404	3,509
Total capitalization	\$7,377	\$7,121	\$7,149
Equity capitalization	53%	52%	51%

The equity capitalization is in line with the Corporation's objectives. Equity capitalization decreased 2% at January 1, 2010, and decreased 3% at December 31, 2010 from that reported under Canadian GAAP as a result of the transitional adjustments to IFRS (see Note 3).

11. CHANGES IN NON-CASH WORKING CAPITAL

	Three Months Ended March 31	
	2011	2010
<i>Operating activities, changes related to:</i>		
Accounts receivable	\$ 44	\$ 35
Inventories	1	(2)
Prepaid expenses and other current assets	7	7
Accounts payable and accrued liabilities	(29)	21
Income taxes recoverable and payable	(2)	5
Other liabilities	5	(11)
	\$ 26	\$ 55
<i>Investing activities, changes related to:</i>		
Accounts receivable	\$ -	\$ 5
Inventories	1	(2)
Accounts payable and accrued liabilities	(8)	(19)
	\$ (7)	\$ (16)

12. RETIREMENT BENEFITS

Information about the Corporation's benefit plans, in aggregate, is as follows:

	Three Months Ended, March 31, 2011		Year Ended December 31, 2010	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Benefit plan assets, obligations and funded status</i>				
<i>Market value of plan assets:</i>				
Beginning of period	\$1,704	\$ -	\$1,531	\$ -
Return on plan assets	28	-	101	-
Employee contributions	1	-	3	-
Employer contributions	13	-	55	-
Benefit payments	(14)	-	(51)	-
Experience gains	2	-	65	-
End of period	\$1,734	\$ -	\$1,704	\$ -
<i>Accrued benefit obligations:</i>				
Beginning of period	\$1,907	\$ 79	\$1,521	\$ 68
Current service cost	10	1	31	2
Interest cost	27	1	104	4
Employee contributions	1	-	3	-
Benefit payments from plan assets ⁽¹⁾	(14)	-	(51)	-
Benefit payments by employer	(1)	-	(5)	(2)
Actuarial losses ⁽²⁾	-	-	304	7
End of period ⁽³⁾	\$1,930	\$ 81	\$1,907	\$ 79
<i>Funded status:</i>				
Accrued asset (liability)	\$ (196)	\$ (81)	\$ (203)	\$ (79)

⁽¹⁾ Pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3% per annum.

⁽²⁾ A decrease in the liability discount rate assumption at December 31 resulted in the actuarial loss in 2010.

⁽³⁾ The non-registered, non-funded defined benefit pension plans accrued benefit obligations increased to \$93 million at March 31, 2011, (December 31, 2010 – \$90 million) due to current service and interest costs.

12. RETIREMENT BENEFITS (continued)

	Three Months Ended March 31			
	2011		2010	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Benefit plan cost</i>				
<i>Components of benefit plan cost:</i>				
Current service cost	\$ 10	\$ 1	\$ 8	\$ -
Interest cost	27	1	27	1
Expected return on plan assets	(28)	-	(27)	-
Defined benefit plans cost	9	2	8	1
Defined contribution plans cost	4	-	2	-
Total cost	13	2	10	1
Less: Capitalized	3	1	1	-
Net cost recognized	\$ 10	\$ 1	\$ 9	\$ 1

Weighted average assumptions

	Three Months Ended March 31			
	2011		2010	
	Pension Benefit Plans	Other Post Employment Benefit Plans	Pension Benefit Plans	Other Post Employment Benefit Plans
<i>Assumptions regarding benefit plan cost:</i>				
Expected long term rate of return on plan assets for the period	6.8%	-	7.0%	-
Liability discount rate for the period	5.6%	5.6%	6.4%	6.4%
Average compensation increase for the period	(1)	-	(1)	-
<i>Assumptions regarding accrued benefit obligations:</i>				
Liability discount rate at March 31	5.6%	5.6%	6.4%	6.4%
Long term inflation rate	2.25%	(2)	2.25%	(2)

⁽¹⁾ The assumed average compensation increases are 3.75% until 2011 and 3.25% thereafter.

⁽²⁾ The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligation are as follows: for drug costs, 6.2% for 2011 grading down over 13 years to 4.5% (2010 - 6.4% for 2010 grading down over 14 years to 4.5%), for other medical costs, 4.5% for 2011 and thereafter (2010 - 4.5% for 2010), and for dental costs, 4.0% for 2011 and thereafter (2010 - 4.0% for 2010 and thereafter).

12. RETIREMENT BENEFITS (continued)

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost for 2010 are outlined in the following table. The sensitivities of each key assumption have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously.

	2010 Pension Benefit Plans		2010 Other Post Employment Benefit Plans	
	Accrued Benefit Obligation	Benefit Plan Cost	Accrued Benefit Obligation	Benefit Plan Cost
Expected long term rate of return on plan assets				
1% increase	-	\$(15)	-	-
1% decrease	-	\$ 15	-	-
Liability discount rate				
1% increase	\$(205)	\$ (5)	\$ (9)	\$ (1)
1% decrease	\$ 254	\$ 6	\$ 11	\$ -
Future compensation rate				
1% increase	\$ 43	\$ 4	-	-
1% decrease	\$ (40)	\$ (4)	-	-
Long term inflation rate				
1% increase ^{(1) (2)}	\$ 152	\$ 13	\$ 8	\$ 1
1% decrease ⁽²⁾	\$(174)	\$(15)	\$ (7)	\$ (1)

⁽¹⁾ The long term inflation rate for pension plans reflects the fact that pension plan benefit payments are indexed to increases in the Canadian Consumer Price Index to a maximum increase of 3.0% per annum.

⁽²⁾ The long term inflation rate for other post employment benefit plans is the assumed annual health care cost trend rate described in the weighted average assumptions.

