ATCO LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2010

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

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

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Glossary

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

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

AESO means the Alberta Electric System Operator.

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

ASL means ATCO Structures & Logistics Ltd.

ATCO Energy Solutions means ATCO Energy Solutions 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.

Class I Shares means Class I Non-Voting Shares of the Corporation.

Class II Shares means Class II Voting Shares of the Corporation.

Corporation means ATCO Ltd. and, unless the context otherwise requires, includes its subsidiaries.

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

GAAP means Canadian generally accepted accounting principles.

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

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

IFRS means International Financial Reporting Standards.

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

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

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

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

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

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

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

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

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

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

U.K. means United Kingdom.

U.S. means United States of America.

Company Overview

Alberta based ATCO Group, with more than 7,700 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), Structures & Logistics (manufacturing, logistics and noise abatement) and Technologies (business systems solutions).

The consolidated financial statements include the accounts of ATCO Ltd. and all of its subsidiaries. At December 31, 2010, the principal subsidiaries were Canadian Utilities Limited (Canadian Utilities), of which ATCO Ltd. owned 52.2% (38.5% of the Class A non-voting shares and 81.7% of the Class B common shares), ATCO Structures & Logistics Ltd., of which Canadian Utilities owned 24.5% and ATCO Ltd. owned on a consolidated basis 88.3% of the Class A non-voting shares and Class B common shares, and ATCO Resources Ltd., of which ATCO Ltd. owned 100% of the Class A non-voting shares and Class B common shares. The consolidated financial statements have been prepared in accordance with GAAP and the reporting currency is the Canadian dollar.

Internal Transfers of Subsidiaries

On January 1, 2011, the Corporation transferred its wholly owned subsidiary, ATCO Resources, to ATCO Power, a wholly owned subsidiary of Canadian Utilities. 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.

The Corporation transferred its common shares of ATCO Resources to Canadian Utilities in exchange for 1,059,658 Class A non-voting shares and 489,171 Class B common shares of Canadian Utilities, having a value of $82.5 million. As a result of this transaction, the Corporation's overall ownership of Canadian Utilities increased from 52.2% to approximately 52.8%. This is a related party transaction between entities under common control and will be measured at the carrying amount. The excess of the fair value of the shares and the carrying value of the investment will be recorded in equity.

In addition, effective October 1, 2010, the ownership of Alberta Power (2000) was transferred from CU Inc. to ATCO Power. Both CU Inc. and ATCO Power are wholly owned subsidiaries of Canadian Utilities.

Segments

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.

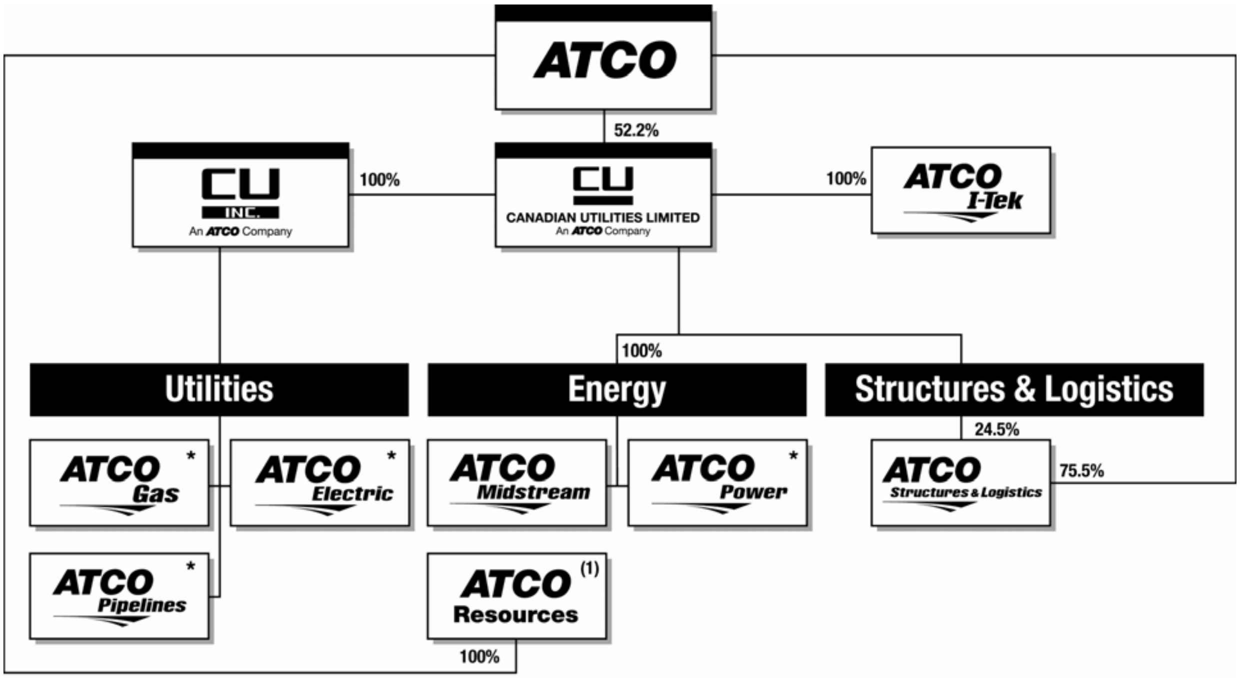
The **Energy** Segment includes:
- the non-regulated supply of electricity and cogeneration steam by ATCO Power and ATCO Resources;
- the regulated supply of electricity by ATCO Power; and
- the non-regulated natural gas gathering, processing, storage and natural gas liquids extraction by ATCO Midstream.

The **Structures & Logistics** Segment includes the following activities provided by ASL:
- the manufacture, sale and lease of transportable workforce housing and space rentals products (Modular Structures division);
- the provision of lodging and support services to the resource sector (Lodging & Support Services division);
- the rapid mobilization and provision of facilities operations and maintenance services for customers in the resource, defence and telecommunications sectors (Facilities Operations & Maintenance division); and
- the design, supply and construction of noise abatement for industrial facilities (Construction division).

The **Corporate & Other** Segment includes:
- the development, operation and support of information systems and technologies, and the provision of billing services, payment processing, credit, collection and call centre services by ATCO I-Tek; and
- short term investments and commercial real estate owned by ATCO Ltd., ATCO Investments Ltd. and Canadian Utilities in Alberta.

Transactions between segments are eliminated in all reporting of the Corporation's consolidated financial information. For additional information about the Corporation's segments, refer to Note 26 to the consolidated financial statements.

Simplified Organizational Structure



* *Regulated operations include ATCO Gas, ATCO Electric, ATCO Pipelines and the Battle River and Sheerness generating plants of ATCO Power.*

(1) *Effective January 1, 2011, the Corporation transferred its 100% ownership interest in ATCO Resources to ATCO Power, a wholly owned subsidiary of Canadian Utilities (refer to Internal Transfer of Subsidiaries section above). This chart describes the organizational structure as at December 31, 2010.*

ATCO AUSTRALIA INITIATIVE

On January 1, 2011, Steven J. Landry was appointed Managing Director & Chief Operating Officer of ATCO Australia Pty Ltd. Based in Perth, Western Australia, Mr. Landry will oversee the Corporation's energy, power generation and infrastructure business, including the three generating plants already in operation in that country. While the existing generating plants were reported in the Energy segment in 2010, effective January 1, 2011, the operations of ATCO Australia will be reported in a separate segment.

REDEMPTION OF $150.0 MILLION OF ATCO PREFERRED SHARES

On March 23, 2010, the Corporation redeemed all of its outstanding 5.75% Cumulative Redeemable Preferred Shares Series 3 (Series 3 Preferred Shares) at a price of $25.586644 (representing the $25.00 designated capital of each share and a prescribed premium of $0.50 per share plus $0.086644 of accrued and unpaid dividends per share). The total cost of this redemption was $153.5 million and was recorded as a $150.0 million reduction in Preferred Shares on the consolidated balance sheet and a $3.5 million increase in Dividends on Preferred Shares expense ($3.0 million prescribed premium and $0.5 million of accrued and unpaid dividends) on the consolidated statement of earnings. As a result of the elimination of dividends as of March 23, 2010, the prescribed premium of $3.0 million was offset by preferred dividend savings of $6.6 million to December 31, 2010. The redemption increased full year 2010 earnings after income taxes by approximately $3.9 million.

KARRATHA GENERATING PLANT

During 2010 the two unit 86 MW natural gas-fired simple cycle generating plant in Karratha, Western Australia (the "Karratha plant"), commenced commercial operations. Due to the nature of the contract governing the Karratha plant's revenues, GAAP requires that this agreement is accounted for as a finance lease (with the Corporation as the lessor). The total net investment in the finance lease is equal to the present value of the minimum lease payments receivable.

As this lease is considered a sales-type finance lease for accounting purposes, $129.8 million was recorded in revenues in 2010 to recognize the fair value of the lease receivable. These revenues were offset by $124.8 million in operation and maintenance expense associated with the construction costs of the two units which were removed from construction work in progress. This resulted in an increase in earnings, after non-controlling interests, of $1.8 million for the year ended December 31, 2010.

Forward-Looking Information

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

Non-GAAP Measures

The Corporation uses the measures "Funds Generated by Operations", "Adjusted Earnings" and "Adjusted Earnings per Class I and Class II Share" in this MD&A. These measures do not have any standardized meaning under GAAP and might not be comparable to similar measures presented by other companies.

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

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

Controls and Procedures

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2010, the Corporation's management evaluated the effectiveness of the Corporation's disclosure controls and procedures, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

Disclosure controls and procedures are controls and other procedures designed to provide reasonable assurance that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis and is accumulated and communicated to the Corporation's management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure.

The Corporation's management, inclusive of the CEO and the CFO, does not expect that the Corporation's disclosure controls and procedures will prevent or detect all errors. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues and instances of error, if any, within the Corporation have been detected.

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

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2010, the Corporation's management evaluated the effectiveness of the Corporation's internal control over financial reporting, as defined under rules adopted by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO.

The Corporation's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting can provide only reasonable assurance with respect to financial statement preparation and may not prevent or detect all misstatements.

Based on this evaluation, the CEO and the CFO have concluded that the Corporation's internal control over financial reporting was effective at December 31, 2010.

There was no change in the Corporation's internal control over financial reporting that occurred during the period beginning on October 1, 2010, and ended on December 31, 2010, that has materially affected, or is reasonably likely to materially affect, the Corporation's internal control over financial reporting.

Annual Results of Operations

SELECTED INFORMATION

($ millions, except per share data, outstanding shares and return on equity) [1] [2]	For the Year Ended December 31 **2010**	2009	2008
Revenues	**3,445.4**	3,108.9	3,265.6
Earnings attributable to Class I and Class II Shares	**292.9**	283.3	272.2
Adjusted Earnings [3]	**296.0**	278.4	266.3
Total assets	**10,239.8**	9,954.6	8,669.2
Long term debt	**3,084.1**	3,138.7	2,886.4
Non-recourse long term debt	**376.1**	439.2	507.8
Preferred shares	**-**	150.0	150.0
Class I and Class II Share owners' equity	**2,213.9**	2,009.6	1,770.1
Return on equity (%)	**13.9**	15.0	16.3
Cash flow from operations	**942.1**	881.3	906.6
Funds Generated by Operations	**929.9**	935.1	923.5
Capital expenditures	**968.7**	986.8	1,081.8
Earnings per Class I and Class II Share ($)	**5.04**	4.89	4.71
Diluted earnings per Class I and Class II Share ($)	**5.02**	4.88	4.67
Adjusted Earnings per Class I and Class II Share ($)[3]	**5.09**	4.81	4.61
Cash dividends declared per share ($):			
5.75% Cumulative Redeemable Preferred Shares, Series 3	**0.45**	1.44	1.44
Class I and Class II Shares	**1.06**	1.00	0.94
Equity per Class I and Class II Share ($)	**38.22**	34.52	30.64
Class I and Class II Shares outstanding, year end (thousands)	**57,924**	58,220	57,779
Weighted average Class I and Class II Shares outstanding (thousands):			
Basic	**58,172**	57,899	57,749
Diluted	**58,327**	58,071	58,239

Notes:

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

(2) *The above data (other than Adjusted Earnings, Adjusted Earnings per Class I and Class II Share, Funds Generated by Operations, Return on equity and Equity per Class I and Class II Share) has been extracted from the financial statements.*

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

RECONCILIATION OF EARNINGS ATTRIBUTABLE TO CLASS I AND CLASS II SHARES AND ADJUSTED EARNINGS

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

	For the Year Ended December 31	
($ millions)	**2010**	2009
Earnings attributable to Class I and Class II Shares	**292.9**	283.3
Mark-to-Market Adjustment (1)	**3.1**	3.9
H.R. Milner Income Tax Reassessment (2)	-	(8.8)
Adjusted Earnings	**296.0**	278.4

SIGNIFICANT NON-OPERATING FINANCIAL ITEMS

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

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

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

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

The mark-to-market adjustment for the derivative asset and derivative liability and the corresponding adjustment for the associated power generation revenue contract liability decreased earnings by $1.1 million, net of non-controlling interests, for the three months ended December 31, 2010 (2009 – decrease of $1.1 million) and decreased earnings by $3.1 million, net of non-controlling interests, for the year ended December 31, 2010 (2009 – decrease of $3.9 million). At December 31, 2010, the natural gas purchase contract derivative asset was $1.5 million (2009 – $26.0 million), the natural gas purchase contract derivative liability was $2.2 million (2009 – nil), and the power generation revenue contract liability was $1.5 million (2009 – $20.4 million). The value of the natural gas purchase contracts derivative asset has declined by $24.5 million and the power generation revenue contract liability has declined by $18.9 million compared to 2009 due mainly to the decline in the forward price of natural gas.

(2) H.R. Milner Income Tax Reassessment

In 2006, Canada Revenue Agency (CRA) issued an income tax reassessment for Alberta Power (2000)'s 2001 taxation year which treated the proceeds received from the sale of the H.R. Milner generating plant to the Balancing Pool as income rather than as a sale of an asset. The Corporation disagreed with CRA's position and appealed the reassessment to the Tax Court of Canada. Due to the uncertainty as to whether the reassessment would ultimately be resolved in the Corporation's favour, the Corporation made a $28.8 million payment and reduced earnings after non-controlling interests by $6.4 million in 2006.

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

The impact of the judgment was a $13.7 million recovery of income tax and related interest expense reassessed by CRA in 2006. In addition, Alberta Power (2000) received interest income of approximately $3.1 million earned on such amounts paid to CRA. These adjustments resulted in an $8.8 million increase in earnings, after non-controlling interests, which was recorded in the third quarter of 2009. In total, Alberta Power (2000) received refunds of approximately $28.0 million, including interest, and net of consequential adjustments to other taxation years arising from the judgment.

CONSOLIDATED REVENUES AND ADJUSTED EARNINGS

Revenues in 2010 **increased** by $336.5 million (11%) over 2009. Of this increase, $129.8 million related to the fair value of the lease for the Karratha plant, which is offset by $124.8 million of operation and maintenance costs. In addition, revenues increased due to a $110.4 million (17%) increase in the Structures & Logistics Segment due to increased manufacturing activity in Canada, Australia and South America and a $109.3 million (8%) increase in the Utilities Segment. The increase in the Utilities Segment was mainly due to increased rate base in ATCO Electric and an AUC decision received on the Carbon Compliance Application, partially offset by Carbon decisions recorded in 2009 (Carbon Decisions) in ATCO Gas and the deferred gas account decision by the Alberta Court of Appeal (Deferred Gas Account Decision) in ATCO Gas (refer to Segmented Information – Utilities section).

Adjusted earnings in 2010 were $296.0 million, an **increase** of $17.6 million (6%) over 2009. This increase was primarily attributable to a $25.5 million (25%) increase in the Utilities Segment due to the Carbon Decisions in ATCO Gas and increased rate base in ATCO Electric, ATCO Gas and ATCO Pipelines (the Utilities), partially offset by the Deferred Gas Account Decision in ATCO Gas. Also contributing to the increase was a $10.9 million (18%) increase in the Structures & Logistics Segment due to higher manufacturing and rental fleet activity in Canada and Australia. These increases were partially offset by a $21.5 million (20%) decrease in the Energy Segment mainly due to lower summer/winter natural gas price differentials for storage (Storage Price Differentials) in ATCO Midstream.

Interest and other income in 2010 **decreased** by $16.9 million to $37.9 million compared to 2009 mainly due to interest income recognized in 2009 on the H.R. Milner Income Tax Reassessment in ATCO Power and decreased earnings from ASL's Saadiyat Island Project in the United Arab Emirates that was recorded in other income. These decreases were partially offset by interest income recognized on ATCO Gas' Carbon Compliance decision (refer to Segmented Information – Utilities section).

CONSOLIDATED EXPENSES

($ millions)	For the Year Ended December 31		
	2010	2009	Change to 2010 (2010-2009)
Operating expenses:			
Natural gas supply	**87.3**	21.7	302%
Purchased power	**54.2**	54.1	0%
Operation and maintenance	**1,510.7**	1,297.9	16%
Selling and administrative	**336.6**	310.5	8%
Franchise fees	**172.7**	163.5	6%
	2,161.5	1,847.7	17%
Depreciation and amortization	**393.9**	375.1	5%
Interest	**244.6**	254.6	(4%)
Dividends on preferred shares	**5.0**	8.6	(42%)
Income taxes	**133.0**	144.2	(8%)
Non-controlling interests	**252.4**	250.2	1%

Operating expenses in 2010 **increased** by $313.8 million (17%) compared to 2009. Natural gas supply expense increased due to higher flow through natural gas purchases in ATCO Midstream. Operation and maintenance expenses were higher due to the lease accounting treatment on the completion of the Karratha plant and increased Canadian, South American and Australian Modular Structures manufacturing activity in ASL.

In 2010, **depreciation and amortization expenses increased** by $18.8 million (5%) over 2009, primarily due to capital additions in 2009 and 2010 in the Utilities.

Interest expense in 2010 **decreased** by $10.0 million (4%) compared to 2009, primarily due to the repayment of non-recourse long term debt in ATCO Power and ATCO Resources and the redemption of $125.0 million of CU Inc. 11.40% debentures on August 15, 2010. These debentures were not refinanced until the November 18, 2010, issuance of $125.0 million of CU Inc. 4.947% debentures. This decrease was partially offset by higher interest on long term debt related to the Karratha plant and the impact of the Deferred Gas Account Decision in ATCO Gas.

In 2010, **dividends on preferred shares decreased** by $3.6 million (42%) compared to 2009, primarily due to lower dividends of $6.6 million as a result of the redemption of the Series 3 Preferred Shares on March 23, 2010, partially offset by the $3.0 million prescribed premium paid on redemption.

In 2010, **income taxes decreased** by $11.2 million (8%) compared to 2009, primarily due to lower income tax rates and reduced income taxes in ASL's European operations.

SEGMENTED INFORMATION

($ millions)	Utilities	Energy	Structures & Logistics	Corporate & Other	Intersegment Eliminations	Total
	For the Year Ended December 31					
2010						
Revenues	**1,476.8**	**1,190.7**	**749.2**	**210.9**	**(182.2)**	**3,445.4**
Earnings attributable to Class I and Class II Shares	**127.6**	**85.1**	**72.5**	**9.1**	**(1.4)**	**292.9**
Mark-to-Market Adjustment (1)	**-**	**3.1**	**-**	**-**	**-**	**3.1**
Adjusted Earnings	**127.6**	**88.2**	**72.5**	**9.1**	**(1.4)**	**296.0**
Capital expenditures	**788.9**	**68.2**	**98.2**	**13.4**	**-**	**968.7**
Operating expenses	**819.6**	**788.7**	**595.2**	**138.8**	**(180.8)**	**2,161.5**
2009						
Revenues	1,367.5	1,075.6	638.8	207.7	(180.7)	3,108.9
Earnings attributable to Class I and Class II Shares	102.1	114.6	61.6	4.7	0.3	283.3
Mark-to-Market Adjustment (1)	-	3.9	-	-	-	3.9
H.R. Milner Income Tax Reassessment (2)	-	(8.8)	-	-	-	(8.8)
Adjusted Earnings	102.1	109.7	61.6	4.7	0.3	278.4
Capital expenditures	776.1	150.6	40.9	19.2	-	986.8
Operating expenses	772.2	614.3	499.5	144.2	(182.5)	1,847.7

<u>*Notes:*</u>
(1) (2) Refer to Significant Non-Operating Financial Items section for a description of the adjustments.

Utilities

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

Utilities **revenues** in 2010 were $1,476.8 million, an **increase** of $109.3 million (8%) over 2009. This increase in revenues was primarily attributable to increased rate base in ATCO Electric and the Carbon Decisions in ATCO Gas, partially offset by the Deferred Gas Account Decision in ATCO Gas.

In 2010, **Adjusted Earnings** were $127.6 million, an **increase** of $25.5 million (25%) over 2009. The primary reasons for higher Adjusted Earnings were the Carbon Decisions in ATCO Gas and increased rate base in the Utilities, partially offset by the Deferred Gas Account Decision in ATCO Gas.

Regulatory Developments

AUC Initiative to Reform Rate Regulation

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

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

Generic Cost of Capital

On November 12, 2009, the AUC issued its decision on the 2009 Generic Cost of Capital proceeding. In this decision, the AUC set the 2009 and 2010 generic return on equity (ROE) at 9.0% for all Alberta utilities which it regulates. The AUC has maintained the concept of a single generic ROE for all utilities, with differences in utility or sector specific risk to be recognized through the adjustments of individual common equity ratios. The AUC determined the common equity ratio to be 36% for ATCO Electric's transmission operations, 39% for both ATCO Electric's distribution operations and ATCO Gas' operations and 45% for ATCO Pipelines' operations.

As part of the same decision, the AUC also set the 2011 generic return on equity at 9.0% on an interim basis subject to change following a subsequent generic proceeding. On December 16, 2010, the AUC initiated a 2011 Generic Cost of Capital proceeding, the scope of which includes, among other things, a full review of cost of capital matters including capital structure and the ROE for 2011. It will also include consideration of whether a formula approach to ROE can be reinstated for 2012. In the absence of a formula approach to ROE, the AUC will then consider how the ROE will be set for 2012. The scope also includes consideration of a management fee on customer contributed assets and how such a fee would be accounted for. The proceeding is scheduled to be completed in the third quarter of 2011 and a decision is expected in the fourth quarter of 2011.

Pension Hearing

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

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

Benchmarking

The Utilities purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a Placeholder basis. An AUC decision was issued on March 8, 2010, which addressed the 2003-2007 Placeholder amounts for the Utilities. The AUC decision approved the adjustments to the Placeholder amounts as filed based on fair market value resulting in no material changes to earnings.

For the 2008 and 2009 period, a separate regulatory process has been established to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The proceeding is scheduled to be completed in the first quarter of 2011 and a decision is expected in the second quarter of 2011.

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

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

Utility Asset Disposition Rate Review Proceeding

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

The AUC has indicated that the Stores Block Decision may have various implications with respect to regulation of Alberta utility companies (including the potential impact of the Carbon Natural Gas Storage Facility decision discussed below). The AUC has stated that it would like to develop a comprehensive understanding of these potential implications through this proceeding and then apply this understanding in a consistent manner in future decisions. At the conclusion of this proceeding, the AUC will issue a decision reflecting its conclusions with respect to the interpretation and application of the guidance provided by the courts and the resulting implications to be used in future proceedings. On November 28, 2008, the AUC suspended the utility asset disposition rate review proceeding until further notice to allow for various related matters currently before the courts to be addressed. As of December 31, 2010, this proceeding remains suspended.

ATCO Electric

2011 and 2012 General Tariff Application

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

2009 and 2010 General Tariff Application

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

Transmission Infrastructure Projects

Northwest Alberta Transmission Projects

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

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

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

AESO Long-Term Transmission System Plan

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

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

500kV High Voltage Direct Current ("HVDC") Project

In 2009, ATCO Electric was authorized by the Alberta Minister of Energy to prepare a facility application to build and operate a new 500kV HVDC transmission line along a corridor on the east side of the province between Edmonton and Calgary. Following approval of the facility application by the AUC, ATCO Electric will construct and operate the new line. In December 2010, ATCO Electric filed its proposal for the project with the AESO at an estimated cost, excluding capitalized interest during construction, of $1.6 billion with an in-service date of December 31, 2013. In February 2011, the AESO revised the required in-service date to mid to late 2014 and directed ATCO Electric to review and update its original proposal for the project incorporating the new in-service date and any revisions to the estimated cost. Once ATCO Electric files and the AESO accepts the revised project proposal, ATCO Electric expects to complete and file the facility application with the AUC in the first quarter of 2011 seeking final approval to construct and operate the facility. Final approval is not anticipated until late 2011. Approval of the facility application is required before construction commences. It is anticipated that the majority of the project costs will be incurred in 2012 through 2014.

Hanna Region Transmission Development ("HRTD") Project

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

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

ATCO Gas

2011 and 2012 General Rate Application

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

Carbon Natural Gas Storage Facility

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

Through its Carbon Compliance application, ATCO Gas sought to recover total revenues from customers of $45.5 million, excluding interest, which would increase ATCO Gas' earnings by a total of $32.7 million. On October 19, 2010, the AUC released the Carbon Compliance decision, approving a recovery from customers of $43.7 million plus interest in the amount of $5.9 million to September 30, 2010. Through numerous regulatory processes, ATCO Gas has previously recorded revenues and earnings of $13.8 million and $9.9 million, respectively, in 2009. Additionally, on April 20, 2010, ATCO Gas received a decision from the AUC approving, on an interim adjustable basis, the implementation of Carbon recovery riders resulting in an increase in ATCO Gas' revenues and earnings of $15.7 million and $11.3 million, respectively. As a result, in the third quarter of 2010, ATCO Gas recognized the remaining amounts pertaining to the Carbon Compliance application and related decision issued by the AUC resulting in an increase in ATCO Gas' revenues, interest income and earnings of $14.2 million, $5.9 million, and $14.5 million, respectively.

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

Deferred Gas Account

ATCO Gas filed an application with the AUC to address, among other things, corrections required to historical transportation imbalances (the process whereby third party natural gas supplies are reconciled to amounts actually shipped in a corporation's pipelines) that have impacted ATCO Gas' deferred gas account. In April 2005, the AUC issued a decision resulting in a 15% decrease in the transportation imbalance adjustments sought by ATCO Gas. The decision resulted in ATCO Gas recovering $9.2 million in natural gas supply costs from customers.

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

2005, 2006, and 2009 General Rate Application

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

ATCO Pipelines

Alberta System Integration

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

In 2009, ATCO Pipelines filed an application with the AUC for the integration of ATCO Pipelines' and NOVA's gas transmission systems in Alberta (Integration Application), and filed a second application with the AUC to approve its 2010, 2011 and 2012 negotiated settlement, which was a condition precedent of the Integration Application.

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

Other Matters

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

Energy

Energy **revenues** in 2010 **increased** by $115.1 million (11%) over the same period in 2009. This increase was primarily attributable to the lease accounting treatment on the completion and commencement of operation of the Karratha plant in Australia, higher merchant performance in ATCO Power's and ATCO Resources' Alberta generating plants due to higher prices in the Alberta electricity market and higher flow through natural gas sales and NGL prices in ATCO Midstream. These increases in revenues were partially offset by decreased Storage Price Differentials in ATCO Midstream, decreased revenues at ATCO Power's Barking generating plant due to the expiry of the revenue contract on

September 30, 2010 (refer to Business Risks – Non-regulated Operations section) and lower exchange rates on conversion of U.K. revenues into Canadian dollars.

Adjusted Earnings were $88.2 million, a **decrease** of $21.5 million (20%) compared to 2009. This decrease was primarily attributable to lower Storage Price Differentials in ATCO Midstream, the expiry of the Barking revenue contract on September 30, 2010, and lower exchange rates on conversion of U.K. earnings into Canadian dollars in ATCO Power. These decreases were partially offset by higher Frac Spreads in ATCO Midstream, higher merchant performance in ATCO Power's and ATCO Resources' Alberta generating plants due to higher Spark Spreads in the Alberta electricity market, and earnings attributable to the lease accounting treatment on the completion and commencement of operations of the Karratha plant.

Power Generation

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

	For the Year Ended December 31		
	2010	2009	Change to 2010 (2010-2009)
Independent Power Plants [1]:			
Canada	**96.0%**	96.3%	(0.3%)
U.K.[2]	**89.7%**	96.3%	(6.6%)
Australia	**90.0%**	96.9%	(6.9%)
Regulated Plants [1] :			
Canada	**89.8%**	91.9%	(2.1%)

Notes:

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

(2) *A planned outage commenced in March 2010 to repair a generator (refer to Unplanned Outage at Barking Generating Plant section).*

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 has revealed cracking associated with the turbine blades. The outage to make an interim repair is likely to extend to the end of March 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.

Unplanned Outage at Barking Generating Plant

On October 25, 2007, ATCO Power's Barking generating plant in the U.K. experienced an unplanned outage due to a failure in a steam turbine generator. Temporary repairs were completed, and on March 6, 2008, ATCO Power announced that the plant had returned to service. In May 2010, a planned outage to finish the repairs to the generator was completed. ATCO Power received insurance proceeds associated with the business interruption and the cost of the repairs. Consequently, there was no significant impact to ATCO Power's 2010 earnings relating to this outage.

Other Power Generation Developments

In November 2008, ATCO Power announced it would design, build, own and operate a two unit 86 MW natural gas-fired simple cycle generating plant in Karratha, Western Australia. On February 14, 2010, the first unit commenced commercial operations followed by the second unit on April 9, 2010.

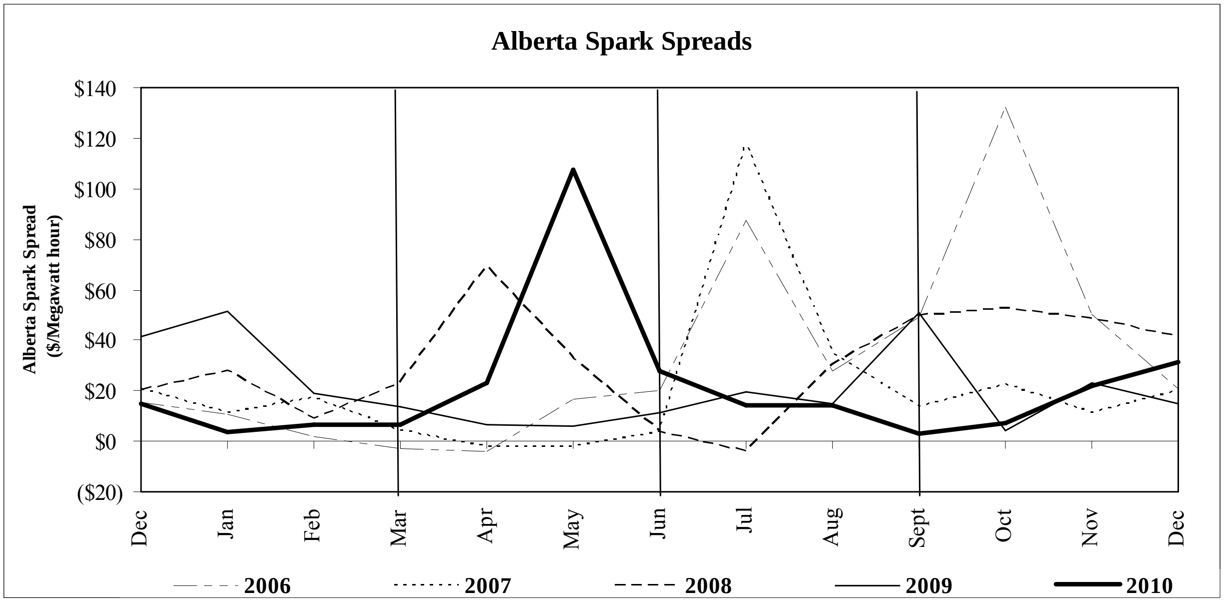
On January 30, 2008, the 150 MW Unit 4 at ATCO Power's Battle River generating plant experienced an unplanned outage due to a failure in the unit's generator. The unit returned to service on March 27, 2008. ATCO Power claimed relief under the force majeure provisions of its PPA. These provisions provide protection for the operator against mechanical failures which last more than forty-two days, except for circumstances where it is found that the operator failed to follow good operating practices. On July 11, 2008, the Balancing Pool notified ATCO Power that it disagreed with the claim. As settlement on the claim could not be reached with the PPA counterparty, the claim proceeded to arbitration. On October 25, 2010, the arbitrator issued a decision which denied ATCO Power's force majeure claim. As the impact of this outage had previously been recorded in 2008, the arbitrator's decision had no effect on the annual financial results for 2010.

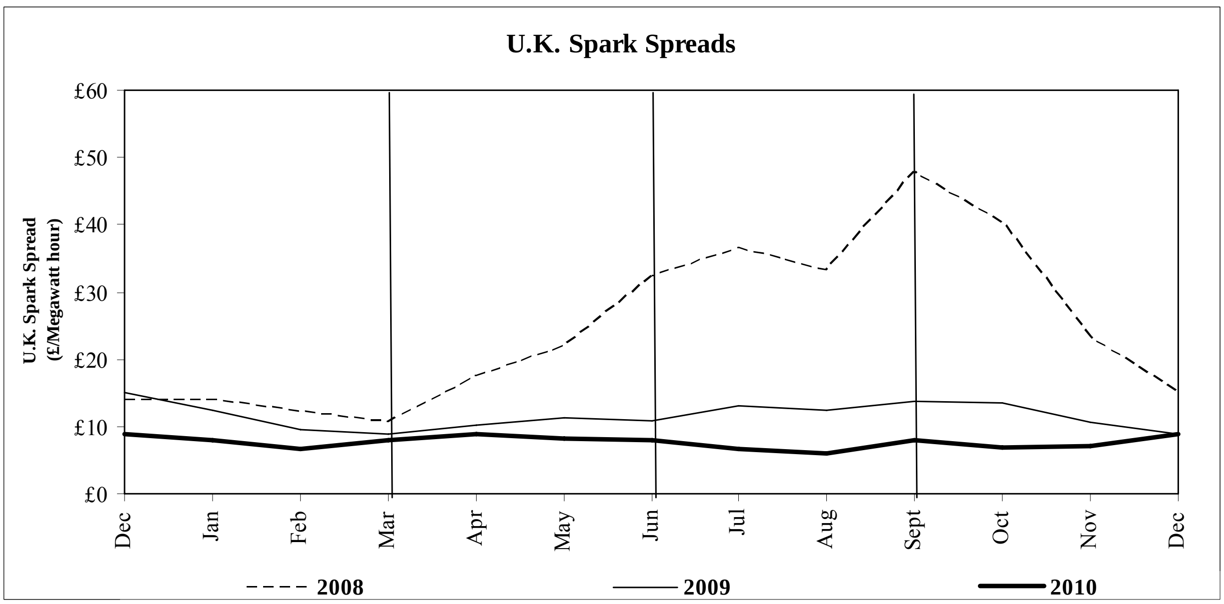
The majority of ATCO Power's and ATCO Resources' electricity sales to the Alberta Power Pool are from natural gas-fired generating plants and, as a result, earnings are affected by natural gas prices and Alberta Power Pool prices. Alberta Power Pool electricity prices averaged $50.88 per MWh in 2010, compared to average prices of $47.81 per MWh in 2009. Natural gas prices averaged $3.79 per GJ, compared to average prices of $3.76 per GJ in 2009. These electricity and natural gas prices resulted in an average Spark Spread of $22.49 per MWh in 2010, compared to $19.58 per MWh in 2009.

As of October 1, 2010, the majority of ATCO Power's Barking generating plant's capacity is exposed to the market prices for electricity, natural gas and emissions allowances. Power prices averaged £41.13 per MWh for the twelve months ended December 31, 2010, compared to average prices of £36.83 per MWh in the corresponding period of 2009. Natural gas prices averaged £3.98 per GJ for the twelve months ended December 31, 2010, compared to average prices of £2.94 per GJ in the corresponding period of 2009. Emissions allowance prices, which are traded in Euros, averaged £12.37 per tonne of CO_2 for the twelve months ended December 31, 2010, compared to average prices of £11.93 per tonne of CO_2, in the corresponding period of 2009. These electricity, natural gas and emissions allowance prices resulted in an average Spark Spread of £7.57 per MWh for the twelve months ended December 31, 2010, compared to average Spark Spreads of £11.28 per MWh in the corresponding period of 2009. Barking's actual merchant sales are not necessarily sold using the same Spark Spread indicator used in the graph below. The graph depicts the spot market whereas the Barking generating plant utilizes forward power sales to attain an element of cash flow certainty. 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.

Changes in Spark Spread currently affect the results of approximately 503 MW of plant capacity owned in Alberta by ATCO Power and ATCO Resources out of a total Alberta-owned capacity of 1,883 MW and 210 MW of plant capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of 255 MW and a worldwide capacity owned by ATCO Power and ATCO Resources of 2,811 MW.

The following charts demonstrates the volatility of Alberta Spark Spreads experienced by ATCO Power and ATCO Resources for the period of December 2005 to December 2010, and the volatility of the U.K. Spark Spreads for the period January 2008 to December 2010.





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.

Regulated Generating Plants

ATCO Power's Battle River and Sheerness generating plants were regulated by the AUC until December 31, 2000, but are now governed by legislatively mandated PPAs that were approved by the AUC. These plants are considered regulated operations primarily because the PPAs are designed to allow the owners of generating plants constructed before January 1, 1996, to recover their forecast fixed and variable costs and to earn a return at the rate specified in the PPAs. Each plant will become deregulated upon the earlier of one year after the expiry of its PPA or a decision to continue to operate the plant. For PPAs expiring prior to 2019, 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 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.

The electricity generated by the Battle River and Sheerness generating plants is sold pursuant to PPAs. Under the PPAs, ATCO Power is required to make the generating capacity for each generating unit available to the purchaser of the PPA for that unit. In return, ATCO Power is entitled to recover its forecast fixed and variable costs for that unit from the PPA purchaser, including a rate of return on common equity equal to the long term Government of Canada bond rate plus 4.5% based on a deemed common equity ratio of 45%. Many of the forecast costs will be determined by indices, formulae or other means for the entire period of the PPA. ATCO Power's actual results will vary and depend on performance compared to the forecasts on which the PPAs were based. The return on common equity rate used in its PPA tariff calculations for ATCO Power was 8.44% in 2010 and 8.64% for 2009. The rate of return on common equity for 2011 is 7.90%.

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

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

During 2010, the **deferred availability incentive** account decreased by $18.9 million to $48.2 million, mainly due to availability penalties paid associated with the planned outage in the second quarter of 2010 for the Battle River generating plant, which occurred during a period of high Alberta Power Pool electricity prices, as well as normal amortization. The amortization of deferred availability incentives, recorded in revenues, decreased by $2.2 million to $14.1 million, primarily as a result of the impact of 2010 planned outages and lower forecast prices for electricity.

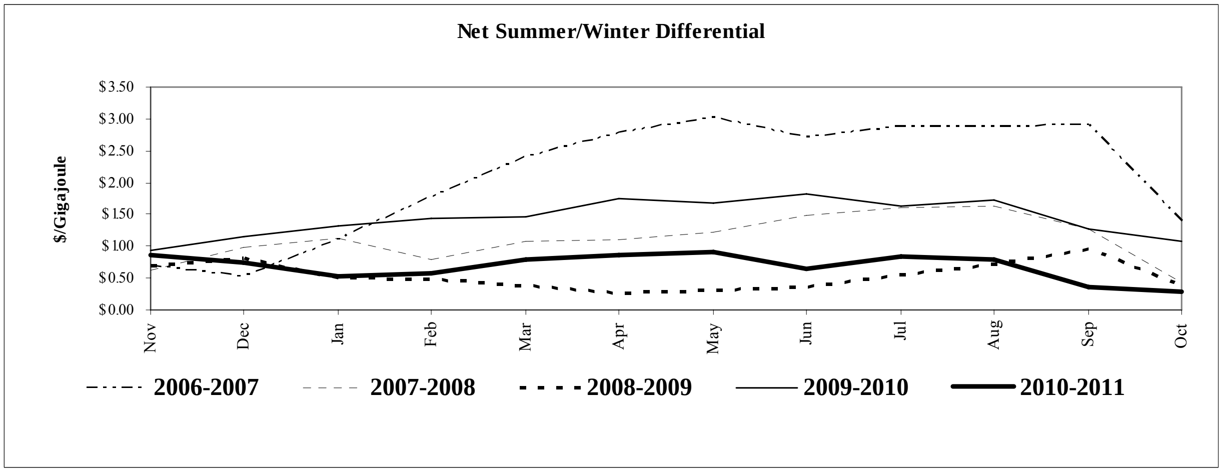
ATCO Midstream

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

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 2006-2007 storage year to the 2010-2011 storage year. Storage Price Differentials at any point in time may not always be indicative of the storage revenue and earnings for the same period due to the types of contracts and the timing of the revenue recognition associated with these contracts.

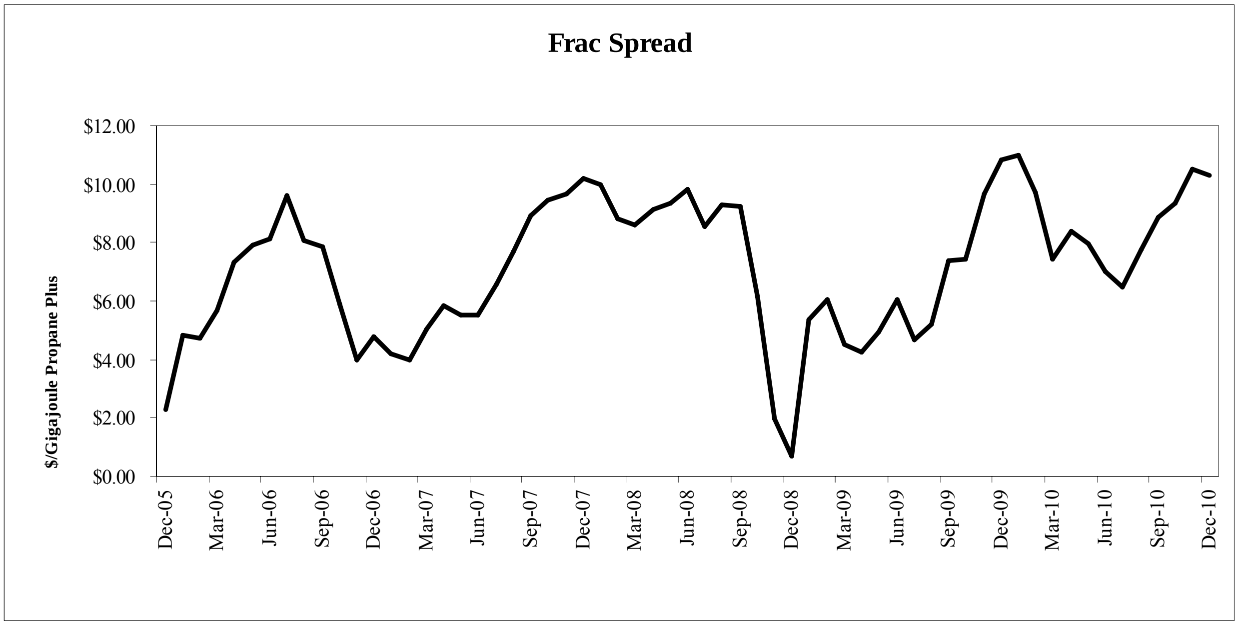


Fluctuations in Storage Price Differentials affect ATCO Midstream's earnings and cash flow from operations. At current values, a $0.25 change in the Storage Price Differentials impacts ATCO Midstream's annual earnings by approximately $8.0 million and impacts the Corporation's consolidated earnings by $4.2 million, after non-controlling interests.

NGL Extraction Operations

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

ATCO Midstream's NGL extraction operations involve the extraction of NGL from natural gas and the replacement (on a heat content equivalent basis) of the NGL extracted with shrinkage gas. For Propane Plus, the difference between the price of natural gas and the value of the liquids extracted is commonly referred to as the Frac Spread. Frac Spreads vary with fluctuations in the price of natural gas and the prices of the applicable liquids extracted. Frac Spreads can be volatile, as shown in the following graph, which illustrates monthly Frac Spreads during the period of December 2005 to December 2010.



Note:
(1) *The above chart represents measurements of industry Frac Spreads in Alberta, as reported by an independent consultant. The average Frac Spread for 2010 was $8.33 per gigajoule compared to $6.36 per gigajoule in 2009.*

Fluctuations in Frac Spreads affect ATCO Midstream's earnings and cash flow from operations. At current volumes, a $1.00 change in the average annual Frac Spread impacts ATCO Midstream's annual earnings by approximately $6.0 million and impacts the Corporation's consolidated earnings by $3.1 million, after non-controlling interests.

Structures & Logistics

ASL is organized into four operating divisions. The Modular Structures division activities include the manufacture, sale and lease of transportable workforce housing and space rental products. The Lodging & Support Services division builds, owns and operates accommodation complexes in locations required by its customers. These accommodation complexes include the Creeburn Lake Lodge and the Barge Landing Lodge. The Facilities Operations & Maintenance division provides rapid mobilization and provision of facilities operations and maintenance services to resource, defence and telecommunications customers. Its activities include the operation and maintenance of the North Warning System and Alaska Radar System and the support services provided to NATO in Afghanistan. The Construction division's activities include the design, supply and construction of noise abatement solutions for industrial facilities.

Structures & Logistics **revenues increased** by $110.4 million (17%) over 2009. The increase was mainly due to increased Canadian, Australian and South American manufacturing operations in the Modular Structures division and increased occupancy in the Lodging & Support Services division.

Adjusted Earnings were $72.5 million, an **increase** of $10.9 million (18%) over 2009. This increase was primarily due to increased Canadian and Australian manufacturing and rental fleet activity in the Modular Structures division, increased earnings in the Facilities, Operations & Maintenance division due to expanded operations and improved margins in Afghanistan, a $4.1 million reduction in income tax expense relating to European operations and increased occupancy in the Lodging & Support Services division. These increases were partially offset by decreased earnings from the Saadiyat Island Project in the United Arab Emirates, which was completed in the first quarter of 2010, and the impact of the 2009 settlement resulting from the cancellation of the Fort Hills Energy Limited Partnership oil sands project.

Modular Structures

The Modular Structures division is engaged in the manufacture, sale and lease of transportable shelters and related products. The Modular Structures division has marketed and installed its manufactured products in more than 100 countries around the world since 1947 and has established a reputation as a leader in the international supply of relocatable shelter products. Products sold are manufactured in Canada, the U.S., Australia, Chile, Peru and United Arab Emirates and under subcontract in other jurisdictions.

	For the Year Ended December 31		
	2010	2009	Change to 2010 (2010-2009)
Manufacturing hours [1]	**943,282**	586,796	61%
Space Rentals Fleet			
Number of units	**15,840**	13,248	20%
Utilization (%)	**78**	73	5%
Average rental rate ($ per month)	**448**	466	(4%)
Workforce Housing Fleet			
Number of units	**2,699**	2,416	12%
Utilization (%)	**78**	74	4%
Average rental rate ($ per month)	**1,236**	1,268	(3%)

Note:
(1) *Manufacturing hours exclude operations in Australia where manufacturing is sub-contracted to third party contractors.*

Recent Developments

In 2010, ASL was awarded two major contracts for workforce housing. On November 23, 2010, ASL announced it was awarded a contract to build a 1,000 bed construction camp in northeastern Ontario for Detour Gold Corporation. Installation is expected to be completed in the first quarter of 2011. On September 16, 2010, ASL announced it had won a contract with a major oilsands company to build a 744 person permanent accommodation facility south of Fort McMurray, with expected completion in November 2011.

Lodging & Support Services

ASL and the Fort McKay First Nation are partners in a joint venture which owns and operates the Creeburn Lake Lodge, a 500-room lodge north of Fort McMurray, Alberta. The Creeburn Lake Lodge accepts clients on a nightly, weekly or monthly basis.

ASL and the Fort McKay First Nation are also partners in a second joint venture which operates the Barge Landing Lodge, a 1,900-room temporary work camp north of Fort McMurray, under various service agreements with several clients.

Facilities Operations & Maintenance

The following is a summary of the principal Facilities Operations & Maintenance division contracts.

Contract	Customer	Start Date	Completion Date	Possible Extension [1]
Alaska Radar System [2]	U.S. Department of Defense	Oct. 2004	Sep. 2011	2014
North Warning System [2]	Department of National Defense	Sep. 2001	Sep. 2011	2013
Iqaluit Fuel Contract [2]	Government of Nunavut	Jun. 2007	Nov. 2012	2017
Stabilization Force Organization	NATO	Feb. 2004	Sep. 2013	2015
NATO Flight Training	NATO	Jun. 2000	May 2020	-
Kandahar Projects:	NATO			
Infrastructure, Support Services, Range & Pest		Sep. 2007	Mar. 2011	-
First Responders		Jan. 2011	Jan 2014	2016
Utilities		Nov. 2010	Nov. 2013	2015
Pass & Permits		Sep. 2007	Sep. 2011	2012

Notes:
(1) *The contract may be extended at the option of the customer.*
(2) *Joint venture with aboriginal partners.*

Recent Developments

On December 15, 2010, ASL announced it had been awarded a three-year contract to provide critical first-responder services for NATO at Kandahar Airfield in Afghanistan. The contract encompasses fire and crash rescue services and emergency ambulance response capability for NATO forces stationed at the military camp. On November 30, 2010, ASL announced it had been awarded a three-year contract to provide utility services for NATO at Kandahar Airfield in Afghanistan. This contract includes two one-year options that can be exercised together or successively. These military camp services support troops serving under NATO's International Security Assistance Force at the Kandahar Airfield.

Corporate & Other

Adjusted Earnings were $9.1 million, an **increase** of $4.4 million (94%) over 2009 mainly due to lower dividends on preferred shares (refer to Company Overview – Redemption of $150.0 million of ATCO Preferred Shares section) and cost efficiencies in ATCO I-Tek. These increases were partially offset by higher share appreciation rights expense resulting from changes in ATCO Class I Non-Voting Share and Canadian Utilities Class A non-voting share prices since January 1, 2010.

ATCO I-Tek

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

ATCO I-Tek provides billing, payment processing, credit, collection and call centre services to its clients. ATCO I-Tek currently provides such services to Direct Energy for its regulated retail and competitive energy supply businesses in Alberta. In addition, ATCO I-Tek supplies distribution-related billing and customer care services to ATCO Gas and ATCO Electric.

Direct Energy entered into a 10 year contract effective May 4, 2004, with ATCO I-Tek to provide billing and call centre services to ensure continued quality customer service. Direct Energy has the ability to terminate this contract after the fifth anniversary, which occurred on May 4, 2009, upon immediate payment of termination fees which decline over the remaining term of the contract. As a result of negotiations in 2010, the contract was extended to December 31, 2014.

Liquidity and Capital Resources

A major portion of the Corporation's operating income and funds generated by operations is generated from its utility operations. Canadian Utilities and its wholly owned subsidiary, CU Inc., use short term bank loans and commercial paper borrowings to provide flexibility in the timing and amounts of long term financing. ATCO Ltd. has received dividends from Canadian Utilities which have been more than sufficient to service debt requirements and pay dividends.

SUMMARY OF CASH FLOW

	For the Year Ended December 31		
($ millions)	**2010**	2009	Change to 2010 (2010-2009)
Cash position, beginning of period	**1,020.2**	848.1	20%
Cash provided by (used in)			
Operating activities:			
Funds Generated by Operations	**929.9**	935.1	(1%)
Changes in non-cash working capital	**12.2**	(53.8)	123%
Cash flow from operations	**942.1**	881.3	7%
Investing activities	**(855.7)**	(872.7)	2%
Financing activities	**(449.6)**	172.3	(361%)
Foreign currency impact on cash balances	**(11.8)**	(8.8)	(34%)
Cash position, end of period	**645.2**	1,020.2	(37%)

OPERATING ACTIVITIES

Funds Generated by Operations were $929.9 million in 2010, virtually unchanged from 2009. In 2010, **changes in non-cash working capital** were $12.2 million, an **increase** of $66.0 million (123%) over 2009. This increase reflects reduced accounts receivable from natural gas storage operations in ATCO Midstream and the receipt of amounts owing to ATCO Power in 2009 as a result of the H.R. Milner Income Tax Reassessment.

INVESTING ACTIVITIES

In 2010, **cash used in investing activities decreased** by 2% compared to 2009, mainly due to lower capital expenditures.

Capital expenditures in 2010 **decreased** by $18.1 million compared to 2009. This decrease was primarily due to decreased investment in non-regulated electric transmission projects by ATCO Energy Solutions and lower costs incurred to complete the Karratha plant in the second quarter of 2010. These decreases in capital expenditures were partially offset by increased investment in the Modular Structures and Facilities Operations & Maintenance divisions in ASL.

Capital Expenditures	**For the Year Ended December 31**		
($ millions)	**2010**	2009	Change to 2010 (2010-2009)
Utilities	**788.9**	776.1	2%
Energy	**68.2**	150.6	(55%)
Structures & Logistics	**98.2**	40.9	140%
Corporate & Other	**13.4**	19.2	(30%)
	968.7	986.8	(2%)

Capital expenditures to maintain capacity, meet planned growth, and fund future development activities are expected to be approximately $1.8 billion in 2011, an increase of $0.8 billion over 2010. The majority of these expenditures relate to the Utilities Segment. For the 2011 to 2013 period, capital expenditures in the Utilities Segment are expected to be approximately $5.0 billion to $6.0 billion (refer to Segmented Information – Utilities – Regulatory Developments – ATCO Electric – Transmission Infrastructure Projects section). These expenditures are expected to be financed by a combination of funds generated by operations and capital market financings.

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

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

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

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

The Corporation is subject to the normal risks associated with major capital projects including delays and cost overruns. Although the Corporation attempts to mitigate these risks by careful planning and entering into long term contracts when possible, there can be no assurance that significant cost overruns or delays will not occur.

FINANCING ACTIVITIES

In 2010, the Corporation had **net debt decreases** of $150.7 million. **Redemptions** were comprised of $125.0 million of 11.40% Debentures due August 15, 2010, $93.3 million of other long term debt and $73.6 million of non-recourse long term debt. **Issuances** of debt included $125.0 million of 4.947% Debentures due November 18, 2050, and $16.2 million of other long term debt.

On December 2, 2010, CU Inc., a wholly owned subsidiary of Canadian Utilities, **issued** $75.0 million of 3.80% Cumulative Redeemable Preferred Shares Series 4. In 2009, CU Inc. **issued** $160.0 million of 6.70% Cumulative Redeemable Preferred Shares Series 2.

On March 23, 2010, the Corporation **redeemed** $150.0 million of 5.75% Cumulative Redeemable Preferred Shares Series 3 (refer to Company Overview – Redemption of $150.0 million of ATCO Preferred Shares section).

Purchases of Canadian Utilities' Class A non-voting shares under its normal course issuer bids were $6.6 million in 2010 compared to nil in 2009. **Issues** of Canadian Utilities Class A non-voting shares due to stock option exercises were $5.5 million in 2010 compared to $6.4 million in 2009. **Net purchases** were $1.1 million in 2010 compared to **net issues** of $6.4 million in 2009.

On March 1, 2010, the Corporation commenced a **normal course issuer bid** for the purchase of up to 3% of the outstanding Class I Shares. The bid will expire on February 28, 2011. From March 1, 2010, to December 31, 2010, 499,200 shares were purchased.

Purchases of Class I Shares under the Corporation's normal course issuer bid were $27.1 million in 2010 compared to nil in 2009. **Issues** of Class I Shares due to stock option exercises were $4.5 million in 2010 compared to $8.4 million in 2009. **Net purchases** were $22.6 million in 2010 compared to **net issues** of $8.4 million in 2009.

Total **dividends paid to Class I and Class II Share owners increased** by 6% to $61.6 million. In 2010, the **quarterly dividend** payment on the Class I and Class II Shares was **increased** by $0.015 to $0.265 per share over 2009. On January 13, 2011, the Board of Directors declared the first quarter dividend of $0.285 per share. The Corporation has increased its annual common share dividend each year since 1993. 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.

Dividends paid to non-controlling interests increased by 7% to $134.3 million, primarily due to higher per share dividends paid by Canadian Utilities, and higher preferred share dividends paid by CU Inc. due to the March 2009 and December 2010 issues, respectively, of Series 2 and Series 4 Preferred Shares.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation decreased the Corporation's cash position by $11.8 million due to changes in U.K. and Australian exchange rates used for balance sheet translations.

SHORT TERM INVESTMENT POLICY

The Corporation has a long-standing policy not to invest any of its cash balances in asset-backed securities. Cash and short term investment credit risk is reduced by investing approximately 75% in short term money market instruments of Canadian financial institutions and Government of Canada treasury bills as at December 31, 2010.

LINES OF CREDIT

At December 31, 2010, the Corporation had the following credit lines that enable it to obtain funding for general corporate purposes.

($ millions)	Total	Used	Available
Long term committed	644.3	30.1	614.2
Short term committed	616.3	36.7	579.6
Uncommitted	113.5	35.5	78.0
Total	1,374.1	102.3	1,271.8

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

- A $200 million unsecured revolving extendible term credit facility of ATCO Ltd. established in 1999 with a syndicate of Canadian chartered banks. This facility will expire in June 2013, unless extended at the option of the lenders;
- A $200 million unsecured revolving extendible term credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility will expire in June 2013, unless extended at the option of the lenders;
- A $100 million unsecured revolving extendible term credit facility of ATCO Midstream established in 1999 with a syndicate of Canadian chartered banks and financial institutions. This facility will expire in August 2013, unless extended at the option of the lenders;
- A $100 million revolving extendible term credit facility of ASL established in 2009 with a Canadian chartered bank. The facility is primarily used to finance working capital and for issues of letters of credit. The facility is secured by first ranking security interests on all present and future property, assets, undertakings and equity interests in certain of its subsidiaries and joint ventures. This facility will expire in September 2012, unless extended at the option of the lenders; and
- Other long term committed lines of credit are a $26 million revolving credit facility of ATCO Power with a Canadian chartered bank and an AUD$18 million revolving credit facility of ASL with an Australian bank. Unless extended at the option of the lenders, ATCO Power's credit facility will expire in August 2013 and ASL's credit facility will expire in July 2012.

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

- A $300 million unsecured revolving extendible credit facility of CU Inc. established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for CU Inc.'s commercial paper program and for occasional issues of letters of credit. This facility will expire in July 2011, unless extended at the option of the lenders;
- A $300 million unsecured revolving extendible credit facility of Canadian Utilities established in 1999 with a syndicate of Canadian chartered banks. This facility is used as a backstop for Canadian Utilities' commercial paper program. This facility will expire in July 2011, unless extended at the option of the lenders; and

- An AUD$16 million secured revolving credit facility of ASL with an Australian bank available for issue of letters of credit.

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

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

CONTRACTUAL OBLIGATIONS

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

	Payments Due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	After 5 Years
($ millions)					
Accounts payable and accrued liabilities	545.1	545.1	-	-	-
Operating leases	117.6	28.0	35.6	23.9	30.1
Long term debt	3,104.8	105.7	170.4	228.2	2,600.5
Non-recourse long term debt	428.6	46.1	84.0	67.3	231.2
Interest expense (1)	3,125.3	216.7	409.7	379.9	2,119.0
Purchase obligations:					
Coal purchase contracts (2)	711.2	66.3	132.7	164.0	348.2
Natural gas purchase contracts (3)	33.8	13.2	20.4	0.2	-
Operating and maintenance agreements (4)	140.5	23.0	44.2	37.6	35.7
Capital expenditures (5)	88.3	88.3	-	-	-
Derivatives (6)	10.1	3.5	3.5	1.8	1.3
Other	30.7	9.6	17.0	3.7	0.4
Total	8,366.0	1,145.5	917.5	906.6	5,366.4

<u>*Notes:*</u>

(1) *Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2010. Interest payments on debt that has been hedged have been estimated using the hedged rates.*

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

(3) *Natural gas purchase contracts consist primarily of ATCO Power and ATCO Resources contracts to purchase natural gas for certain of their natural gas-fired generating plants. ATCO Power and ATCO Resources have long term offtake agreements with the purchasers of the electricity to recover 100% of these costs. The ATCO Power and ATCO Resources merchant components of their generating plants in Alberta and the U.K. do not have any long term contracts to purchase natural gas.*

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

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

(6) *Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2010.*

BASE SHELF PROSPECTUS

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

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

Share Capital

The equity securities of the Corporation consist of Class I Shares and Class II Shares.

At February 18, 2011, the Corporation had outstanding 51,074,956 Class I Shares, 6,853,408 Class II Shares, and options to purchase 555,200 Class I Shares.

CLASS I NON-VOTING SHARES AND CLASS II VOTING SHARES

Each Class II Share may be converted into one Class I Share at any time at the share owner's option. In the event an offer to purchase Class II Shares is made to all owners of Class II Shares, and is accepted and taken up by the owners of a majority of such shares pursuant to such offer, and provided an offer is not made to the owners of Class I Shares on the same terms and conditions, the Class I Shares shall be entitled to the same voting rights as the Class II Shares. The two classes of shares rank equally in all other respects.

Of the 5,100,000 Class I Shares authorized for grant in respect of options under the Corporation's stock option plan, 1,594,100 Class I Shares were available for issuance at December 31, 2010. Options may be granted to officers and key employees of the Corporation at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant. As of February 18, 2011, options to purchase 555,200 Class I Shares were outstanding.

SERIES 3 PREFERRED SHARES

On March 23, 2010, the Corporation redeemed all of its outstanding 5.75% Cumulative Redeemable Preferred Shares Series 3 (Series 3 Preferred Shares) at a price of $25.586644 (representing the $25.00 designated capital of each share and a prescribed premium of $0.50 per share plus $0.086644 of accrued and unpaid dividends per share). The total cost of this redemption was $153.5 million and was recorded as a $150.0 million reduction in Preferred Shares on the consolidated balance sheet and a $3.5 million increase in Dividends on Preferred Shares expense ($3.0 million prescribed premium and $0.5 million of accrued and unpaid dividends) on the consolidated statement of earnings. As a result of the elimination of dividends as of March 23, 2010, the prescribed premium of $3.0 million was offset by preferred dividend savings of $6.6 million. The redemption increased full year 2010 earnings after income taxes by approximately $3.9 million.

Business Risks

ENERGY PRICES

A combination of an increasing power reserve margin (the amount of power supply in excess of demand) and low natural gas prices has led to a decrease in Alberta and U.K. power prices and the commensurate Spark Spreads. This affects approximately 503 MW of merchant power capacity owned in Alberta by ATCO Power and ATCO Resources out of a total Alberta-owned capacity of approximately 1,883 MW and, since October 1, 2010, 210 MW of merchant power capacity owned in the U.K. by ATCO Power out of a total U.K.-owned capacity of 255 MW.

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

PENSION PLANS

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

Declines in stock and bond markets, changes in actuarial assumptions and additional employee service have created funding deficits in the Corporation's defined benefit pension plans. Prior to 2010, the Corporation had not made material contributions since April 1, 1996, as a result of the defined benefit plans' surplus position. In addition the Corporation had obtained regulatory approval to fund the employer's contributions to the defined contribution component of the pension plan from the defined benefit plan surplus.

Material current service and deficit funding contributions resumed in 2010. The actual funding contributions for 2010 were established based on actuarial valuations for funding purposes as of December 31, 2009. Based on these final actuarial valuations, the employer contributions relating to both the defined contribution and the defined benefit components of the plan for 2010 were approximately $75 million. Contributions commenced during the first quarter of 2010. The next actuarial valuation for funding purposes is required to be completed as of December 31, 2012.

For purposes of any pension funding requirements pertaining to utility operations, the AUC has directed that the cash basis of accounting be used in customer rate applications. Accordingly, the Corporation includes the cost of funding in its rate applications to the AUC, thereby, with the consent of the AUC, recovering approximately 73% of the costs of funding its pension plans from utility customers (refer to Segmented Information – Utilities section). The net funding contribution amounts (actual funding contributions less recovery from utility customers) were approximately $20 million. Pension funding contributions do not equate to pension expense for accounting purposes. A description of pension expense can be found in Note 22 of the Corporation's consolidated financial statements for the year ended December 31, 2010.

FINANCING

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

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

As at December 31, 2010, the Corporation had cash balances of approximately $645 million and available committed and uncommitted lines of credit of approximately $1.3 billion which can be utilized for general corporate purposes.

ENVIRONMENTAL MATTERS

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

Greenhouse Gas Emissions

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

Compliance reports for any GHG obligations must be submitted annually to Alberta Environment by March 31 for the previous calendar year. The settlement of the obligation will be achieved through a combination of approved compliance options including: improved unit performance, emission performance credits, offset credits and technology fund credits. PPA counterparties have reimbursed ATCO Power for amounts relating to their GHG obligations. Due to lower emissions per unit of output, ATCO Power's and ATCO Resources' gas-fired generating units have minimal exposure to Alberta's GHG regulation and some of the cogeneration facilities generated emission performance credits which can be used for internal compliance as noted above.

ATCO Power participated in a working group established by Alberta Environment tasked with reviewing the method used to determine the GHG obligation for cogeneration units. A new method is expected in early 2011 that will apply to the 2011 reporting year, and could have an impact on ATCO Power's cogeneration plants. Until this methodology is finalized, the impact cannot be determined.

The Government of Canada has announced plans to reduce GHG emissions in the electricity sector by moving forward with regulations on coal-fired generation. Draft regulations are expected to be published in early 2011. Regulations are scheduled to come into effect on July 1, 2015. The approach would apply a "clean as gas" performance standard to new coal-fired generation units and units that have reached the end of their economic life, currently deemed as 45 years from the unit's commissioning date. The government has indicated that appropriate options will be considered in the process of developing the regulations and in the determination of the end-of-life date.

As inscribed in the Copenhagen Accord, Canada has aligned its GHG target with the United States at a 17% reduction from 2005 levels by 2020. It is not clear how this commitment could impact the electricity sector beyond the proposed coal regulation. Accordingly, significant regulatory uncertainty and a wide range of potential outcomes remain. ATCO Power continues to monitor and actively engage the federal government in this area to manage the associated risks.

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

The Barking generating plant in the U.K. complies with the European Union Emissions Trading Scheme (EU-ETS) which is currently in its second phase until the end of 2012. Under this second of three phases, Barking is allocated a free allowance of 1.4 million tonnes towards total annual emissions of up to 2.8 million tonnes. Until September 30, 2010, Barking's long term power purchasers were responsible for 72.5% of the plant's emissions and they received a pro-rata share of the free allocation. The remaining free allocations were applied to the sale of merchant energy to the market. Since October 1, 2010, Barking sells its free allocations to the EU-ETS market. Barking then purchases emissions allowances from the EU-ETS market, as required, on a forward basis concurrently with forward power sales. This approach currently provides a full recovery of these emissions compliance costs.

ATCO Power's Australian generating plants are expected to be regulated by an Australian Government carbon pollution reduction scheme. All of ATCO Power's Australian plants have long term contractual power purchase arrangements allowing full recovery of costs associated with complying with any emissions regulations.

Air Pollutants

Alberta regulation requires coal-fired generating plant operators, including ATCO Power, to monitor mercury emissions and target a capture of at least 70% of the mercury in the coal commencing January 1, 2011. Alberta Environment approved the Corporation's proposed solution and mercury control equipment was installed at the Battle River and Sheerness generating plants.

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

In October 2010, federal and provincial environment ministers agreed to move forward with a new air management approach. The proposed new system will include more ambitious air quality standards and consistent industrial emissions standards across Canada. Ministers have directed officials to develop the major elements of the system in 2011 with implementation to start in 2013. The Corporation is represented in the regulatory consultation process through the Canadian Electricity Association and is also participating in the working groups that have been set up to assist with the development of this air management system. It is uncertain how a federal system would impact the existing provincial frameworks.

Cost Recovery

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

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

PIPELINE INTEGRITY

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

CARBON NATURAL GAS STORAGE FACILITY

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

REGULATED OPERATIONS

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

The Utilities are subject to the normal risks faced by companies that are regulated. These risks include the approval by the AUC of customer rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance by the AUC, of costs incurred. The Utilities' ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting process. The determination of fair rate of return on the common equity component of rate base is an earnings and cash flow risk for the Utilities and is currently the subject of the 2011 Generic Cost of Capital proceeding (refer to Annual Results of Operations – Segmented Information – Utilities section).

Benchmarking

The Utilities purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. Since 2003, the costs have been approved on a Placeholder basis. An AUC decision was issued on March 8, 2010, which addressed the 2003-2007 Placeholder amounts for the Utilities. The AUC decision approved the adjustments to the Placeholder amounts as filed based on fair market value resulting in no material changes to earnings.

For the 2008 and 2009 period, a separate regulatory process has been established to approve rates for information technology and customer care and billing services provided by ATCO I-Tek that can be included in customer rates. The proceeding is scheduled to be completed in the first quarter of 2011 and a decision is expected in the second quarter of 2011.

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

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

Transfer of the Retail Energy Supply Businesses

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy and one of its affiliates (collectively, Direct Energy), a subsidiary of Centrica plc. ATCO Gas and ATCO Electric continue to own and operate the natural gas and electricity distribution systems used to deliver energy.

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

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

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

Measurement Inaccuracies in Metering Facilities

Measurement inaccuracies occur from time to time with respect to the Utilities' metering facilities. Measurement adjustments are settled between parties based on the requirements of the Electricity and Gas Inspections Act (Canada) and applicable regulations issued pursuant thereto. There is a risk of disallowance of the recovery of a measurement adjustment if controls and timely follow up are found to be inadequate by the AUC.

Regulated Generating Plants

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

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

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

NON-REGULATED OPERATIONS

Independent Power Plants

The Corporation's portfolio of non-regulated electric generating plants is made up of gas-fired cogeneration, gas-fired combined cycle and gas-fired simple cycle plants as well as a small hydro plant. The majority of operating income from power generation operations is derived through long term power, steam and transmission support agreements. Where long term agreements are in place, the purchaser assumes the fuel supply and price risks and the Corporation, under these agreements, assumes the operating risks.

ATCO Power's and ATCO Resources' generating plants include high efficiency gas-fired cogeneration plants, with associated on-site steam and power tolling arrangements, and gas-fired peaking and hydroelectric plants with underlying transmission support agreements. For the first nine months of 2010, sales from approximately 69% of ATCO Power's and ATCO Resources' generating capacity were subject to long term agreements, while the remaining 31% consisted primarily of sales to the Alberta Power Pool and the U.K. merchant power market. On September 30, 2010, the Barking power plant revenue contracts expired reducing the contracted capacity to approximately 63%, net of increased capacity at the Muskeg River plant. The U.K. and Alberta merchant sales are dependent on prices in the Alberta electricity spot market and in the U.K. merchant power market. The majority of the electricity sales to the Alberta Power Pool are from gas-fired generating plants, and as a result, operating income is affected by natural gas prices. During peak electricity usage hours in Alberta, a correlation exists between electricity spot prices and natural gas spot prices. During off-peak hours, there is less correlation.

Changes and volatility in Alberta Power Pool electricity prices, natural gas prices and related Spark Spreads may have a significant impact on the Corporation's earnings and cash flow from operations in the future. The Corporation manages this volatility through its adoption of asset optimization strategies in accordance with its risk management policy for bidding its merchant power into both the Alberta and U.K. power markets.

The revenue contract for the Barking power plant expired on September 30, 2010. A new tolling contract for 178 MW (ATCO Power's share 45 MW) of the plant's capacity was entered into for a one-year term commencing October 1, 2010. The remaining 822 MW of the plant's capacity (ATCO Power's share 210

MW) was sold into the merchant market commencing October 2010. A substantial portion of the U.K. electricity market is comprised of vertically integrated companies whose operations include both generation and supply. Market participants trade primarily through structured bilateral contracts and wholesale markets, with smaller volumes traded on a power exchange. Approximately 40% of the electricity generated is supplied from natural gas-fired generating plants. Changes in the U.K. market electricity prices may have an impact on the Corporation's earnings and cash flow from operations in the future.

ATCO Power and ATCO Resources have financed the majority of their non-regulated electrical generating capacity on a non-recourse basis. In these projects, the lender's recourse in the event of default is limited to the business and assets of the project in question, which includes the Corporation's equity therein. Canadian Utilities has provided a number of guarantees related to ATCO Power's and ATCO Resources' obligations under their respective non-recourse loans associated with certain of their projects. ATCO Power (80%) and ATCO Resources (20%) have a joint venture in the Canadian projects subject to guarantees, excluding McMahon. ATCO Ltd. has indemnified and agreed to reimburse Canadian Utilities for any amounts it may be required to pay under these guarantees in respect of ATCO Resources' 20% interest. ATCO Ltd.'s indemnification to reimburse Canadian Utilities for any amounts payable under ATCO Resources 20% interest was cancelled effective January 1, 2011, when ATCO Resources was transferred to ATCO Power (refer to Company Overview – Internal Transfer of Subsidiaries section). The guarantees outstanding at December 31, 2010, are described in Note 13 to the consolidated financial statements. To date, Canadian Utilities has not been required to make any payments related to its guaranteed obligations.

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

ATCO Midstream

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

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

At ATCO Midstream's NGL facilities, the Corporation contracts commercial arrangements with pipeline shippers who hold NGL extraction rights on those pipelines delivering gas to the NGL facilities. In June 2007, the AUC initiated an industry-wide review of NGL extraction rights. On February 4, 2009, a decision was issued with respect to NOVA's natural gas transmission system that, in most cases, proposes to transfer ownership of the NGL extraction rights to the receipt point shippers (generally producers) from the border delivery shippers (generally exporters from the province who include ATCO Midstream's suppliers). NOVA has confirmed that it is committed to the NGL Extraction Convention application and has indicated a filing date in the second quarter of 2011. With anticipated hearing and transition timelines, full implementation would likely not occur before November 2013. The earnings and cash flow impact on certain of ATCO Midstream's NGL extraction facilities is uncertain at this time.

ASL

ASL products are directly related to the capital spending cycle and the level of development activity in natural resource and energy industries, which, in turn, are largely dependent on commodity prices. Changes in commodity prices of natural resources may have a significant impact on the Corporation's earnings and cash flow from operations.

ASL's operations include providing support to military agencies in foreign locations which may be subject to war risk. ASL maintains insurance, including war risks, to mitigate the risk associated with the nature of these contracts. Additionally, in areas where the risk of injury is considered to be severe, ASL confines its staff to specific military compounds and all employees are given pre-deployment orientation and ongoing safety training.

ATCO I-Tek

The Utilities purchase information technology services from ATCO I-Tek. ATCO Electric and ATCO Gas also purchase customer care and billing services from ATCO I-Tek. The recovery of these costs in customer rates is subject to AUC approval. In 2009, the Utilities completed a review of three options for the future provision of information technology and customer care and billing services. The options are (i) the repatriation of these services back into the Utilities; (ii) moving to a third party service provider; or (iii) renewing with ATCO I-Tek, the current service provider. Remaining with ATCO I-Tek was determined to be the least expensive option and the recommendation that the Utilities submitted to the AUC. A decision from the AUC is expected in 2012 on this recommendation.

Derivative Financial Instruments

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risks arising from fluctuations in exchange rates, interest rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes. For details on the financial instruments in place at December 31, 2010, see Note 23 to the consolidated financial statements.

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

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

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

At inception of a hedge, the Corporation documents the relationship between the hedging instrument and the hedged item, including the method of assessing retrospective and prospective hedge effectiveness. At the end of each period, the Corporation assesses whether the hedging instrument has been highly effective in offsetting changes in fair values or cash flows of the hedged item and measures the amount of any hedge ineffectiveness. The Corporation also assesses whether the hedging instrument is expected to be highly effective in the future.

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

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

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

Hedge gains or losses that were recognized in other comprehensive income are added to the initial carrying amount of a non-financial asset or non-financial liability when:
(i) an anticipated transaction for a non-financial asset or non-financial liability becomes a specific firm commitment for which fair value hedge accounting is applied or,
(ii) a cash flow hedge of an anticipated transaction subsequently results in the recognition of the non-financial asset or non-financial liability.

(b) A non-hedge derivative instrument is recorded on the consolidated balance sheet at fair value and subsequent changes in fair value are recorded in earnings.

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

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

Transactions with Related Parties

On January 1, 2011, the Corporation transferred its wholly owned subsidiary, ATCO Resources, to ATCO Power, a wholly owned subsidiary of Canadian Utilities. For a more detailed description, refer to Company Overview – Internal Transfers of Subsidiaries section.

In other transactions with entities related through common control, the Corporation sold and rented manufactured product and recovered administrative expenses totaling $0.1 million (2009 – $0.4 million) and incurred advertising, promotion and administrative expenses totaling $2.2 million (2009 – $2.3 million). At December 31, 2010, there were no accounts receivable due from entities related through common control (2009 – nil).

Except for the transfer of ATCO Resources to ATCO Power, these transactions are in the normal course of business and under normal commercial terms, measured at the exchange amount.

Off-Balance Sheet Arrangements

There are tax loss carryforwards of $11.1 million for foreign subsidiary corporations for which no benefit has been recorded. Tax losses of $0.7 million begin to expire in 2020 and the remaining $10.4 million of tax losses do not expire. There are net capital loss carryforwards of $4.4 million for ATCO Ltd. and a Canadian subsidiary corporation for which no tax benefit has been recorded. For additional information about the Corporation's unrecorded future income tax liabilities, refer to note 6 to the consolidated financial statements.

The Corporation does not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, such considerations as liquidity and capital resources.

Contingencies

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

Critical Accounting Estimates

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

DEFERRED AVAILABILITY INCENTIVES

ATCO Power is subject to an incentive/penalty regime related to generating unit availability of the Battle River and Sheerness generating plants. The amount to be amortized is dependent upon estimates of future generating unit availability and future electricity prices over the term of the PPAs. Each quarter, management uses these estimates to forecast high case, low case and most likely scenarios for the incentives to be received from, less penalties to be paid to, the PPA counterparties. These forecasts are added to the accumulated unamortized deferred availability incentives outstanding at the end of the quarter; the resulting total is divided by the remaining term of the PPAs to arrive at the amortization for the quarter. As at December 31, 2010, the Corporation had recorded $48.2 million of deferred availability incentives. The amortization of deferred availability incentives recorded in revenues amounted to $14.1 million in 2010.

Compared to the most likely scenario recorded in revenues for the year, the high case scenario would have resulted in higher revenues of approximately $3.3 million, whereas the low case scenario would have resulted in lower revenues of approximately $4.2 million.

EMPLOYEE FUTURE BENEFITS

The expected long term rate of return on pension plan assets is determined at the beginning of the year on the basis of the high quality long bond yield rate plus an equity and management premium that reflects the plan asset mix. A premium of 0.6% was added to the high quality long bond yield rate of 6.4%, resulting in an expected long term rate of return of 7.0% for 2010. This methodology is supported by actuarial guidance on long term asset return assumptions for the Corporation's defined benefit pension plans, taking into account asset class returns, normal equity risk premiums, asset diversification effect on portfolio returns and a recent change in the Corporation's portfolio asset mix policy.

Expected return on plan assets for the year is calculated by applying the expected long term rate of return to the market related value of plan assets, which is the average of the market value of plan assets at the end of the preceding three years. The expected long term rate of return declined to 7.0% in the year ended December 31, 2010. The result has been a decrease in the expected return on plan assets and a corresponding increase in the cost of pension benefits. In addition, the actual return on plan assets over the preceding three years has been lower than expected (i.e., an experience loss), which is also contributing to an increase in the cost of pension benefits as losses are amortized to earnings.

Accrued benefit obligations at the end of the year are determined using a discount rate that reflects market interest rates that match the timing and amount of expected benefit payments. The liability discount rate has also declined to 5.6% at the end of 2010. The result is an increase in benefit obligations (i.e., an experience loss), which contributes to an increase in the cost of pension benefits as losses are amortized to earnings.

In accordance with the Corporation's accounting policy to amortize cumulative experience gains and losses in excess of 10% of the greater of the accrued benefit obligations or the market value of plan assets, the Corporation is amortizing a portion of the net cumulative experience losses on plan assets and accrued benefit obligations over the expected average remaining service life of employees.

The assumed annual health care cost trend rate increases used in measuring the accumulated post employment benefit obligations in the year ended December 31, 2010, are as follows: for drug costs, 6.4% starting in 2010 grading down over 14 years to 4.5%, and for other medical and dental costs, 4.5% and 4.0%, respectively, for 2010 and thereafter. Combined with lower recent claims experience, the effect of these changes has been to decrease the costs of other post employment benefits.

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

The sensitivities of key assumptions used in measuring accrued benefit obligations and benefit plan cost 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.

($ millions)	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 [(1)]	-	(3.7)	-	-
1% decrease [(1)]	-	3.7	-	-
Liability discount rate				
1% increase [(1)]	(65.2)	(4.8)	(2.8)	(0.3)
1% decrease [(1)]	79.9	5.8	3.4	0.1
Future compensation rate				
1% increase [(1)]	13.4	1.7	-	-
1% decrease [(1)]	(12.8)	(1.7)	-	-
Long term inflation rate				
1% increase [(1) (2) (3)]	45.7	5.4	2.5	0.2
1% decrease [(1) (3)]	(51.6)	(6.1)	(2.2)	(0.3)

Notes:

(1) *Sensitivities are net of the associated regulatory asset (liability) and unrecognized defined benefit plans cost, which reflect an AUC decision to record costs of employee future benefits in the regulated operations, excluding ATCO Power, when paid rather than accrued.*

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

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

Changes in Accounting Policies

FUTURE ACCOUNTING CHANGES

International Financial Reporting Standards

The Corporation will begin reporting under International Financial Reporting Standards (IFRS) in the first quarter of 2011 with comparative data for the prior year. IFRS uses a conceptual framework similar to Canadian GAAP, but there are significant differences in recognition, measurement and disclosures.

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

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

IFRS Conversion Project Status

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

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

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

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

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

Rate Regulated Accounting

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

In the absence of a rate regulated activities standard, the Corporation will not recognize regulatory assets and liabilities. As a result, there will be a reduction to assets of approximately $470 million, a reduction to liabilities of approximately $620 million, an increase to equity of approximately $80 million, and an increase to non-controlling interests of approximately $70 million on transition to IFRS.

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

Significant Accounting Differences between Canadian GAAP and IFRS

The Corporation has identified that the following areas have the greatest potential impact on the Corporation's accounting: leases, employee benefits and regulatory assets and liabilities.

Leases

The Corporation is party to a number of project contracts that IFRS requires be reassessed to determine if they are to be accounted for as deemed leases. The Corporation's assessment is that several contracts will be deemed to be finance leases under IFRS with the Corporation as the lessor. Lease treatment was not required under Canadian GAAP as the contracts were entered into prior to the effective date of the Canadian GAAP standard.

For those arrangements deemed to be finance leases under IFRS, the project property, plant and equipment will be derecognized and a finance lease receivable measured as the present value of the lease payments to be received over the remaining life of the arrangement will be recognized. Payments received from the customer are allocated between interest income classified as revenue and principal payment based on a mortgage style calculation. The transition to IFRS will result in an increase to finance lease receivables of approximately $420 million and corresponding adjustments to Property, Plant and Equipment and Other Assets, and a reduction of approximately $10 million to Retained Earnings and approximately $5 million to non-controlling interests on the Consolidated Balance Sheet.

Employee Benefits

Employee benefits consist of pensions and other retirement benefits, including life insurance and medical care. Under Canadian GAAP, the Corporation amortizes experience gains and losses and other adjustments in excess of 10% of the greater of the accrued benefit obligation or the market value of plan assets to earnings over the remaining average service life of employees. This method is known as the corridor approach.

IFRS allows an entity to recognize the experience gains and losses on plan assets and liabilities in a number of ways:

- recognize 100% of annual gains and losses directly in earnings;
- amortize cumulative unamortized gains and losses exceeding the greater of 10% of plan assets or liabilities over the estimated average remaining service life of employees; or
- recognize 100% of annual gains and losses directly in other comprehensive income and then transfer them directly to retained earnings. The Corporation will adopt this method. Other comprehensive income will be more volatile; the level of volatility will depend upon the gains or losses experienced.

Joint Arrangements

Under Canadian GAAP, the Corporation's numerous joint arrangements are accounted for using proportionate consolidation. Under proportionate accounting, the Corporation records its proportionate share of the assets, liabilities, revenues and expenses of the joint arrangement. Under the IFRS exposure draft on joint arrangements, if the joint arrangement (and not the Corporation) has indirect interests to share in the "net" common outcome expected to be generated from a group of underlying assets and liabilities under the joint control of all of the venturers, the Corporation would account for those joint arrangements using equity accounting and report the investment in joint venture on the balance sheet and equity earnings on the statement of earnings.

The IASB has not yet issued a new joint arrangements standard and its effective date will therefore be subsequent to the IFRS conversion date of January 1, 2011. The Corporation has adopted the option under the existing IFRS standard for Interests in Joint Ventures to account for jointly controlled entities using proportionate accounting. As a result, there will effectively be no change to the Corporation's financial results from the accounting for joint ventures under Canadian GAAP.

IFRS 1 Exemptions

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

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

Description of IFRS 1 Exemption	Project Status
Business Combinations An entity may elect not to restate business combinations that occurred before the date of transition to IFRS.	The Corporation will adopt this exemption, thereby resulting in no changes to the accounting for prior business combinations.
Employee Benefits An entity may elect to recognize all cumulative actuarial gains and losses at the date of transition as an adjustment to retained earnings.	The Corporation will adopt this exemption. This will result in a reduction of defined pension plan assets of approximately $125 million, non-controlling interests of approximately $50 million, deferred income tax liability of approximately $35 million and retained earnings of approximately $55 million, and an increase in retirement benefit obligation of approximately $15 million on transition to IFRS.
Fair Value as Deemed Cost An entity may elect to measure items of property, plant and equipment at fair value at the date of transition to IFRS and use that fair value as deemed cost.	The Corporation will adopt this exemption. This will result in a reduction of approximately $190 million to property, plant and equipment, approximately $50 million to deferred income tax liabilities, approximately $60 million to non-controlling interests and approximately $80 million to retained earnings on transition to IFRS.
Rate Regulated Property, Plant and Equipment An entity that is subject to rate regulation may elect to use the carrying amount of property, plant and equipment determined under previous GAAP as initial cost on transition to IFRS.	Except as indicated below, the Corporation will adopt this exemption, with the result that, except for the reclassification of customer contributions to other liabilities (see Financial Statement Reclassifications below), there will be no change in the Utilities' transitional balances for property, plant and equipment. The Corporation will not adopt this exemption for the regulated generating plants of ATCO Power which will result in a reduction of approximately $100 million to property, plant and equipment, approximately $25 million to deferred income tax liability, approximately $35 million to non-controlling interests and approximately $40 million to retained earnings on transition to IFRS.

Description of IFRS 1 Exemption	Project Status
Cumulative Translation Differences For all of its foreign operations, an entity may elect to recognize its cumulative translation adjustments at the date of transition as an adjustment to retained earnings.	The Corporation will adopt this exemption, thereby resulting in a decrease to retained earnings of approximately $30 million on transition to IFRS.
Decommissioning Liabilities – Asset Retirement Obligations An entity may elect to estimate the amount that would have been included in the cost of the related asset when the liability first arose by discounting the liability back to that date and calculating the accumulated depreciation at the transition date using the current estimated useful life.	The Corporation will adopt this exemption resulting in a reduction of property, plant and equipment of approximately $10 million, an increase in provisions and other liabilities of approximately $15 million and $5 million, respectively, and a reduction in non controlling interests of approximately $10 million, deferred income taxes of approximately $10 million and retained earnings of approximately $10 million on transition to IFRS.

Financial Statement Reclassifications

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

Customer Contributions:

The Corporation obtains contributions from utility customers to construct assets in situations where it is not economic to provide service to those customers at the approved rate charged to other customers. Under Canadian GAAP, the contributions are deducted from property, plant and equipment and amortized over the life of the related asset. Under IFRS, this contribution will be accounted for as deferred revenue on the basis that there is no stand-alone value for utility customers who provide these contributions without ongoing service by the Corporation. The deferred revenue will be amortized over the life of the related asset. The transition to IFRS will result in an increase to assets and liabilities of approximately $880 million as unamortized customer contributions are reclassified from an offset to property, plant and equipment to other liabilities on the consolidated balance sheet.

Long Term Debt Due Within One Year:

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

Employee Benefits

Approximately $212 million will be reclassified to defined benefit assets from other assets and retirement benefit obligations, and approximately $75 million to retirement benefit obligations from other liabilities.

Provisions:

Under IFRS, provisions must be separately disclosed on the consolidated balance sheet. The transition to IFRS will result in the reclassification of approximately $90 million from deferred credits to provisions.

The provision for the power generation revenue contract liability, which under Canadian GAAP was shown separately as a liability, will not be recorded under IFRS. The options within the natural gas purchase contracts will be recorded at fair value as a derivative asset.

Non-Controlling Interests:

Under IFRS, non-controlling interests are presented as a component of equity separate from the parent share owners' equity. Non-controlling interests under Canadian GAAP were presented as a separate item outside of share owners' equity. The transition to IFRS will result in the reclassification of approximately $2,220 million of non-controlling interests to the equity section of the consolidated balance sheet.

Nature vs. Function Presentation of the Statement of Earnings:

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

Quarterly Results of Operations

SELECTED INFORMATION

	For the Three Months Ended (1) (2) (3)				
($ millions except per share data)	Mar. 31	Jun. 30	Sep. 30	Dec. 31	Total
2010					
Revenues	898.5	844.0	761.1	941.8	3,445.4
Earnings attributable to Class I and Class II Shares	89.8	61.7	59.2	82.2	292.9
Earnings per Class I and Class II Share	1.54	1.06	1.02	1.42	5.04
Diluted earnings per Class I and Class II Share	1.54	1.05	1.02	1.41	5.02
Adjusted Earnings (4)	91.9	61.7	59.1	83.3	296.0
Adjusted Earnings per Class I and Class II Share (4)	1.58	1.06	1.02	1.43	5.09
2009					
Revenues	875.1	688.1	684.3	861.4	3,108.9
Earnings attributable to Class I and Class II Shares	94.6	49.5	61.0	78.2	283.3
Earnings per Class I and Class II Share	1.64	0.85	1.05	1.35	4.89
Diluted earnings per Class I and Class II Share	1.63	0.85	1.05	1.35	4.88
Adjusted Earnings (4)	96.1	49.7	53.3	79.3	278.4
Adjusted Earnings per Class I and Class II Share (4)	1.66	0.86	0.92	1.37	4.81

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, the timing of rate decisions and changes in market conditions impacting ASL's workforce housing and space rentals operations.*

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

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

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

- growth in ASL's workforce housing and space rentals operations;
- unplanned and planned outages affecting availability in ATCO Power's and ATCO Resources' generating plants;
- the timing of utility rate decisions;
- fluctuations in natural gas prices, electricity prices and related Spark Spreads in Alberta and the U.K.;
- changes in market conditions in ATCO Midstream's NGL and storage operations;

- exchange rates;
- increase in rate base in the Utilities Segment;
- expiry of the Barking revenue contracts;
- Carbon Decisions;
- mark-to-market adjustments in ATCO Power;
- H.R. Milner Income Tax Reassessment; and
- changes in share appreciation rights expense due to changes in the Corporation's Class I Share and Canadian Utilities' Class A non-voting share prices.

Fourth Quarter 2010

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

SEGMENTED INFORMATION

	For the Three Months Ended December 31					
($ millions)	Utilities	Energy	Structures & Logistics	Corporate & Other	Intersegment Eliminations	Total
2010						
Revenues	**412.0**	**297.9**	**224.4**	**59.5**	**(52.0)**	**941.8**
Earnings attributable to Class I and Class II Shares	**37.3**	**24.3**	**20.3**	**0.9**	**(0.6)**	**82.2**
Mark-to-Market Adjustment (1)	**-**	**1.1**	**-**	**-**	**-**	**1.1**
Adjusted Earnings	**37.3**	**25.4**	**20.3**	**0.9**	**(0.6)**	**83.3**
2009						
Revenues	367.9	306.9	178.3	53.9	(45.6)	861.4
Earnings attributable to Class I and Class II Shares	27.5	38.8	15.8	(4.1)	0.2	78.2
Mark-to-Market Adjustment (1)	-	1.1	-	-	-	1.1
Adjusted Earnings	27.5	39.9	15.8	(4.1)	0.2	79.3

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

Revenues for the three months ended December 31, 2010, **increased** by $80.4 million (9%) over 2009. This increase was primarily attributable to a $46.1 million (26%) increase in the Structures & Logistics Segment due to increased manufacturing activity in Canada, Australia, South America and the U.S. and a $44.1 million (12%) increase in the Utilities Segment mainly due to increased rate base in ATCO Electric. These increases were partially offset by a decrease of $9.0 million (3%) in the Energy Segment due to lower Storage Price Differentials in ATCO Midstream and decreased revenues at ATCO Power's Barking generating plant due to the expiry of the revenue contract on September 30, 2010, offset by higher flow through natural gas sales and NGL prices in ATCO Midstream.

Adjusted Earnings for the three months ended December 31, 2010, **increased** by $4.0 million (5%) over 2009. This increase was primarily due to a $9.8 million (36%) increase in the Utilities Segment mainly due to increased rate base in the Utilities and higher tax deductible costs associated with the capital program in ATCO Electric, a $4.5 million (28%) increase in the Structures & Logistics Segment which benefited from higher manufacturing fleet activity in Canada, Australia, South America and the U.S. and a $5.0 million (122%) increase in Corporate & Other mainly due to lower administrative expenses. These increases were partially offset by a $14.5 million (37%) decrease in the Energy Segment mainly due to lower Storage Price Differentials in ATCO Midstream and lower power prices and spark spreads in the U.K. electricity market in ATCO Power.

Alberta Power Pool electricity prices for the three months ended December 31, 2010, averaged $45.94 per MWh, compared to average prices of $46.27 per MWh in the corresponding period in 2009. Natural gas prices for the three months ended December 31, 2010, averaged $3.44 per GJ, compared to average prices of $4.31 per GJ in the corresponding period in 2009. The consequence of these changes in electricity and natural gas prices was an average Spark Spread of $20.17 per MWh for the three months ended December 31, 2010, compared to $13.93 per MWh in the corresponding period in 2009.

U.K. power prices averaged £48.15 per MWh for the three months ended December 31, 2010, compared to average prices of £34.48 per MWh in the corresponding period of 2009. Natural gas prices averaged £4.93 per GJ for the three months ended December 31, 2010, compared to average prices of £2.56 per GJ in the corresponding period of 2009. Emissions allowance prices, which are traded in Euros, averaged £12.74 per tonne of CO_2 for the three months ended December 31, 2010, compared to average prices of £12.43 per tonne of CO_2 in the corresponding period of 2009. These electricity, natural gas and emissions allowance prices resulted in an average Spark Spread of £7.54 per MWh for the three months ended December 31, 2010, compared to an average Spark Spread of £11.02 per MWh in the corresponding period of 2009.

Interest and other income for the three months ended December 31, 2010, **decreased** by $5.7 million (43%) compared to 2009, primarily as a result of decreased earnings from the Saadiyat Island Project and decreased foreign exchange gains in ASL.

OTHER EXPENSES

($ millions)	For the Three Months Ended December 31		
	2010	2009	Change to 2010 (2010-2009)
Operating expenses:			
Natural gas supply	**50.8**	4.0	1,170%
Purchased power	**14.7**	14.3	3%
Operation and maintenance	**379.8**	356.1	7%
Selling and administrative	**107.3**	104.5	3%
Franchise fees	**46.8**	43.9	7%
	599.4	522.8	15%
Depreciation and amortization expenses	**99.2**	94.6	5%
Interest	**57.0**	66.8	(15%)
Dividends on preferred shares	**-**	2.1	(100%)
Income taxes	**38.9**	38.3	(2%)
Non-controlling interests	**72.7**	71.9	1%

Fourth quarter **operating expenses increased** by $76.6 million (15%) over 2009. Natural gas supply expense increased due to higher flow through natural gas purchases in ATCO Midstream. Operation and maintenance expenses were higher due to increased manufacturing activity in Canada, Australia, South America and the U.S. in ASL.

Depreciation and amortization expenses for the three months ended December 31, 2010, **increased** by $4.6 million (5%) over 2009, primarily due to capital additions in 2010 in the Utilities Segment.

Interest expense for the three months ended December 31, 2010, **decreased** by $9.8 million (15%) compared to 2009, primarily due to the redemption of $125.0 million of CU Inc. 11.40% debentures on August 15, 2010. These debentures were not refinanced until the November 18, 2010, issuance of $125.0 million of CU Inc. 4.947% debentures. Also contributing to the decrease in interest expense was the repayment of long term debt in ASL and the repayment of non-recourse long term debt in ATCO Power and ATCO Resources.

For the three months ended December 31, 2010, **dividends on preferred shares decreased** by $2.1 million (100%) to nil due to the March 23, 2010, redemption of ATCO's Series 3 Preferred Shares.

LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CASH FLOW

	For the Three Months Ended December 31		
($ millions)	**2010**	2009	Change to 2010 (2010-2009)
Cash position, beginning of period	**539.3**	1,175.0	(54%)
Cash provided by (used in)			
Operating activities:			
Funds Generated by Operations	**236.0**	272.0	(13%)
Changes in non-cash working capital	**23.9**	(80.2)	130%
Cash flow from operations	**259.9**	191.8	36%
Investing activities	**(263.1)**	(210.9)	(25%)
Financing activities	**115.1**	(134.5)	186%
Foreign currency impact on cash balances	**(6.0)**	(1.2)	(400%)
Cash position, end of period	**645.2**	1,020.2	(37%)

OPERATING ACTIVITIES

For the three months ended December 31, 2010, **Funds Generated by Operations decreased** by $36.0 million (13%) compared to 2009. This decrease was primarily due to decreases in non-current regulatory assets and liabilities in the Utilities which vary from quarter to quarter and are, therefore, not comparable or indicative of funds generated by operations on an annual basis. For the three months ended December 31, 2010, **changes in non-cash working capital** were $23.9 million, an **increase** of $104.1 million (130%) compared to the corresponding period in 2009. This increase was primarily due to increased accounts payable in ATCO Electric due to higher payments owing to customers for the settlement of one time regulatory items in 2009, and in ASL due to increased Canadian, Australian, South American and U.S. manufacturing activity, and lower accounts receivable resulting from reduced natural gas storage and flow through gas sales in ATCO Midstream.

INVESTING ACTIVITIES

Cash used in investing activities in the fourth quarter **increased** by 25% compared to 2009, primarily as a result of higher capital expenditures on regulated transmission and distribution projects in ATCO Electric and changes in non-cash working capital due to increased payments to ATCO Electric's capital program suppliers.

C**apital expenditures** were essentially unchanged at $296.4 million in 2010 compared to $293.4 million in 2009.

FINANCING ACTIVITIES

In the fourth quarter, the Corporation had **net debt increases** of $101.7 million. **Issuance** of debt included $125.0 million of 4.947% Debentures due November 18, 2050, and $1.7 million of other long term debt. **Redemptions** of debt were comprised of $6.1 million of other long term debt and $18.9 million of non-recourse long term debt.

On December 2, 2010, CU Inc., a wholly owned subsidiary of Canadian Utilities, **issued** $75.0 million of 3.80% Cumulative Redeemable Preferred Shares Series 4.

In the fourth quarter of 2010, there were **purchases** of $1.7 million of Canadian Utilities Class A non-voting shares under its normal course issuer bid, compared to nil in 2009. In the fourth quarter, **issues** of Canadian Utilities Class A non-voting shares due to stock option exercises were $3.6 million, compared to $3.7 million in the corresponding period of 2009. **Net issues** were $1.9 million in 2010, compared to $3.7 million in 2009.

In the fourth quarter of 2010, there were **purchases** of $13.6 million of Class I Shares under the Corporation's normal course issuer bid, compared to nil in 2009. In the fourth quarter, **issues** of Class I Shares due to stock option exercises amounted to $2.5 million, compared to $5.6 million in 2009. **Net purchases** were $11.1 million in 2010, compared to **net issues** of $5.6 million in 2009.

In the fourth quarter, total **dividends paid to Class I and Class II Share owners increased** by 6% over 2009 to $15.3 million. In the fourth quarter, the **quarterly dividend** payment on the Corporation's Class I and Class II Shares **increased** by $0.015 over 2009 to $0.265 per share.

Dividends paid to non-controlling interests increased by 5% to $33.8 million due to higher dividends paid by Canadian Utilities.

FOREIGN CURRENCY TRANSLATION

Foreign currency translation decreased the Corporation's cash position by $6.0 million due to changes in U.K. and Australian exchange rates used for balance sheet translations.

Additional Information

Canadian Utilities has published its audited consolidated financial statements and its MD&A for the year ended December 31, 2010. Copies of these documents may be obtained upon request from the Corporate Secretary of Canadian Utilities at 1400 ATCO Centre, 909-11th Avenue S.W., Calgary, Alberta, T2R 1N6, telephone 403-292-7500 or fax 403-292-7623.