AltaCanada Energy Corp.

Annual Information Form

For the Year Ended December 31, 2009

April 16, 2010

ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form the abbreviations set forth below have the following meanings:

"**bbl**"	Barrel	"**mboe**"	1,000 barrels of oil equivalent
"bbls"	Barrels	**"mcf"**	1,000 cubic feet
"bbls/d"	barrels per day	**"mcf/d"**	one thousand cubic feet per day
"bcf"	1,000,000,000 cubic feet	**"mmbbls"**	1,000,000 barrels
"boe"	barrels of oil equivalent	**"mmbtu"**	one million British Thermal Units
"boe/d"	barrels of oil equivalent per day	**"mmcf"**	1,000,000 cubic feet
"bopd"	barrels of oil per day	**"mmcf/d"**	one million cubic feet per day
"GJ"	Gigajoule	**"mstb"**	1,000 stock tank barrels
"m^3"	cubic metre volume	**"NGL"**	natural gas liquids
"mbbls"	1,000 barrels	**"stb"**	stock tank barrel

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"**ABCA**" means the *Business Corporations Act* (Alberta), S.A. 1981, c. B-15 or the *Business Corporations Act* (Alberta), RSA 2000, c. B-9, as the context requires, together with any amendments thereto and all regulations promulgated thereunder;

"AltaCanada" or the "**Corporation**" means AltaCanada Energy Corp.;

"ANG Holding" means ANG Holding Corp., an Alberta Corporation incorporated in 2003 and wholly-owned by AltaCanada;

"ANGUS" means ANG Holding (USA) Corp., a Montana Corporation incorporated in 2003 and wholly-owned by ANG Holding;

"**ARTC**" means the Alberta royalty tax credit;

"**Board**" means the board of directors of the Corporation;

"**CDN**" means Canadian;

"**Common Shares**" means the Common Shares in the share capital of the Corporation;

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent qualified reserves evaluator and auditor of Calgary, Alberta;

"**GLJ Report**" means the independent engineering evaluation of the Corporation's light and medium oil, heavy oil, natural gas and NGL reserves prepared by GLJ prepared March 22, 2010 and effective December 31, 2009;

"ML&E" means Montana Land & Exploration, Inc. a Montana Corporation incorporated in 2002 and wholly-owned by ANGUS;

"**NI 51-101**" means Canadian Securities Administrators' National Instrument 51-101 – Standards of Disclosure For Oil and

Gas Activities;

"**Partnership**" means the AltaCanada Energy Partnership, a general partnership formed by AltaCanada and Selecta, pursuant to the laws of the Province of Alberta;

"**Selecta**" means Alberta Selecta Corporation, an Alberta Corporation incorporated in 1988 and wholly owned by AltaCanada;

"**Statement**" means the statement and disclosure provided in this Annual Information Form under the heading "Statement of Reserves Data and other Oil and Gas Information";

"**TSX-VE**" means the TSX Venture Exchange;

"**US**" means the United States of America; and

"**working interest**" means the interest in a lease that carries with it the rights and obligations to develop and operate a gas or oil property.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

FORWARD LOOKING STATEMENTS AND OTHER CAUTIONARY NOTES

This Annual Information Form (this "**AIF**") contains forward-looking statements. These statements relate to future events or future performance of the Corporation. When used in this AIF, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "estimate", "predict", "seek", "propose", "expect", "potential", "continue", and similar expressions, are intended to identify forward-looking statements. These statements involve 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 statements. Such statements reflect the Corporation's current views with respect to certain events, and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation's actual results, performance, or achievements to vary from those described in this AIF. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this AIF as intended, planned, anticipated, believed, estimated, or expected. Specific forward-looking statements in this AIF, among others, include statements pertaining to the following:

- factors upon which the Corporation will decide whether or not to undertake a specific course of action;
- world-wide supply and demand for petroleum products;
- expectations regarding the Corporation's ability to raise capital;
- treatment under governmental regulatory regimes; and
- commodity prices.

With respect to forward-looking statements in this AIF, the Corporation has made assumptions regarding, among other things:

- the impact of increasing competition;
- the Corporation's ability to obtain additional financing on satisfactory terms;
- the Corporation's ability to obtain exploration and development services and equipment on an absolute basis, or on terms considered by the Corporation to be justifiable; and
- the Corporation's ability to attract and retain qualified personnel.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this AIF:

- general economic conditions;
- volatility in global market prices for oil and natural gas;
- competition;
- liabilities and risks, including environmental liability and risks, inherent in oil and gas operations;
- the availability of capital; and
- alternatives to and changing demand for petroleum products.

Furthermore, statements relating to “reserves” or “resources” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitable in the future.

The forward–looking statements contained in this AIF are expressly qualified in their entirety by this cautionary statement. These statements speak only as of the date of this AIF. The Corporation does not intend and does not assume any obligation, to update these forward-looking statements to reflect new information, subsequent events or otherwise, except as required by law.

The information with respect to net present values of future net revenues from reserves presented throughout this AIF, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value. It should not be assumed that the net present values of future net revenues from reserves presented in the tables contained in this AIF are representative of the fair market value of the reserves.

The estimates of reserves and future net revenue for individual properties contained herein may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

- world market forces, including the ability of OPEC to set and maintain production levels and prices for crude oil;
- political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;
- increases or decreases in crude oil quality and market differentials;
- the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by AltaCanada for its crude oil and natural gas;
- North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;
- global and domestic economic and weather conditions;
- price and availability of alternative fuels; and
- the effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, quality differentials and foreign exchange and interest rates, among other factors, are outside of management's control. To mitigate a portion of these risks, AltaCanada actively evaluates price risk management activities.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. AltaCanada actively competes for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than AltaCanada. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a worldwide basis and as such have greater and more diverse resources on which to draw.

THE CORPORATION

Incorporation and Organization

AltaCanada was incorporated under the ABCA by a Certificate of Incorporation dated November 12, 1997. The articles of AltaCanada were amended by a Certificate of Amendment dated January 16, 1998 to remove private company provisions, to permit the issuance of preferred shares, to increase the minimum number of directors to three (3) and the maximum number of directors to eleven (11) and to allow for the appointment of additional directors between annual shareholder meetings.

AltaCanada owns, directly or indirectly, 100% of the issued and outstanding securities of Selecta. Selecta is a private oil and gas company that was incorporated under the ABCA in 1988 and is registered to carry on business in Alberta. The Partnership was formed June 1, 2003 and is currently owned 70.5% by AltaCanada and 29.5% by Selecta. AltaCanada also owns 100% of the issued and outstanding securities of ANG Holding, which owns 100% of the issued and outstanding securities of ANGUS, which owns 100% of the issued and outstanding securities of ML&E. See "Business of the Corporation".

The head and registered offices of AltaCanada, Selecta and ANG Holding are located at 1300, 140 – 4th Avenue S.W., Calgary, Alberta, Canada, T2P 3N3; Telephone (403) 265-9091; Fax (403) 265-9021. The registered offices of ANGUS and ML&E are located at 158 Main Street, PO Box 790, Shelby, Montana, USA, 59474.

BUSINESS OF THE CORPORATION

Three Year History

AltaCanada is a publicly traded oil and gas company engaged in the business of, exploration for, and development, production and marketing of, petroleum and natural gas in western Canada and Montana. As at December 31, 2009, all of AltaCanada's Canadian operations were in the province of Alberta.

During 2007, AltaCanada concentrated on exploration activities at Fort Belknap, Montana. Montana acreage increased from 203,946 (174,707 net) acres to 401,692 (226,522 net) acres primarily due to additions at Fort Belknap where the Corporation was successful on 96% of the tracts bid on an April, 2007 land sale. Ten (5.8 net) wells were drilled in Montana. Five (4.5 net) wells were drilled in the Corporation’s production area of Cherry Patch, Montana, with a 67% success rate and following the shooting and analysis of 55 miles of 2-D seismic five (1.25 net) exploratory wells were drilled at Fort Belknap with 100% success.

During 2008, AltaCanada's focused virtually all of its activity on the Fort Belknap exploration lands. Early in the year, AltaCanada acquired an additional 25 percent (66,600 net acres) on the Fort Belknap Reservation, including a 25 percent interest in 6 (1.5 net) gas wells. This acquisition was financed by issuing 7,250,000 Common Shares valued at $2.3 million.

In 2008, a total of 8 (4.2 net) wells were drilled in Montana resulting in 6 (3.05 net) gas wells. In early January 2009, an additional 5 (2.7 net) wells were drilled on the Fort Belknap Reservation resulting in 5 more successful gas completions. These 5 wells together with 11 others previously drilled were placed on production on February 9, 2009 after completion of thirty miles of new steel and plastic gathering system installation. This significant pipeline extension now opens up new exploratory lands with several identified exploration leads.

With lower commodity prices later in 2009 activity was significantly reduced, all drilling and recompletion opportunities were deferred and production from Fort Belknap was suspended until gas prices improve.

Including Montana and Canadian production, total corporate production was 1.55 mmcfd as at March 30, 2009.

The Corporation entered into an amended Forbearance Agreement with its bank on November 27, 2009. Under the terms of this agreement, AltaCanada was required to secure new financing in the amount of $2.5 million by February 28, 2010. This requirement was not accomplished, however, the bank has agreed to a further amendment that contemplates the completion of our rights offering by June 1, 2010. The Corporation will be conducting a $7.5 million rights offering to its shareholders. A major shareholder of the Corporation has provided a standby commitment to purchase at least 71,714,786 Common Shares for an aggregate $5.02 million, paying $2.5 million in cash and converting debentures valued at $2.52 million. The bank agreement requires a payment of $1.25 million by July 31, 2010 and the remaining $8.25 million will continue subject to an engineering evaluation of the lending base.

A Bridging Loan Facility was entered into with a major shareholder and an affiliate of a major shareholder on December 30, 2009. This loan bears interest of eight percent. The loan matures July 30, 2010. One of the conditions of this loan is that AltaCanada shall have closed an equity financing and received net proceeds there from of no less than $ 5.0 million by no later than February 26, 2010. This requirement was not accomplished and the lender has agreed to extend that date to May 31, 2010.

The Corporation requires financing for working capital and the exploration and development of its properties. The Corporation's continuance as a going concern is dependent upon its ability to obtain adequate financing and to reach profitable levels of operation. It is not possible to predict whether financing efforts will be successful or if the Corporation will attain profitable levels of operation. If the Corporation ceased to be a going concern, adjustments necessary to the recoverability and classification of recorded assets and liabilities could be material.

On March 31, 2010, AltaCanada announced that, subject to all necessary regulatory approvals, it will be issuing rights to all shareholders to Common Shares for maximum aggregate gross proceeds of $7,500,000. A major shareholder of the Corporation has agreed to backstop $5,020,000 of this rights offering.

No new wells were drilled in Canada with activity restricted to 1 re-completion and 1 tie-in.

2010 Activities

As at the date of this AIF, AltaCanada has insufficient capital to conduct any activities. To alleviate this situation the Corporation will be conducting a rights offering to the shareholders to raise between $2.5 million and $7.5 million of new equity. A major shareholder and director has agreed to backstop $5.02 million of this offering.

These funds will be directed to several Jurassic (Lower Shaunavon) oil opportunities previously identified by seismic selected high return gas recompletion opportunities, and repayment of certain financial obligations.

Strategy

As at December 31, 2009, AltaCanada maintained its net debt at $18.9 million. Operationally, the management of AltaCanada chose a strategy of limiting expenditures on development which resulted in lower natural gas sales in 2009, and diverting funds to a large exploration effort at Fort Belknap, Montana, which, with success, will create more value to shareholders in the longer term. The management of AltaCanada believes that the oil and gas industry will continue its trend toward consolidation, especially with junior exploration and production companies of similar size to AltaCanada. The management of AltaCanada believes that value can be added to the Corporation by focusing on corporate and asset opportunities in Canada and by consolidating its assets in Montana.

To this end, AltaCanada has had extensive discussions with several corporate entities with regards to a possible sale or merger of the Corporation or major recapitalization. Several potential joint venture partners have also expressed an interest in the Corporation's oil projects.

Montana Drilling

The Eagle sandstones are the stratigraphic equivalent of the Milk River sands of southeast Alberta and southwest Saskatchewan and are the Corporation's principal objective. On the Canadian side, Canadian technology developed from several thousand wells has extended this shallow gas play to the distal limits of tighter sandstones and siltstones. Drilling costs are typically lower for shallow gas plays (and can be lowered further with coiled tubing applications) and flow rates have been improved by low water loss muds and fracture techniques. All of these can, and will, be applied in Blaine County.
Blaine County is both a conventional sand play and a tight sand reservoir. The west side of AltaCanada's block has great quality reservoirs with over 100 feet of sand yielding 500 mcf/d unfractured. On the east side, progressively tighter sands are present, which require significant "fracs" to produce 30 to 100 mcf/d. Between these areas AltaCanada has wells that can initially produce between 200-300 Mcf/d. Additionally, Blaine County has an important structural component providing our

“pop-up” targets with significant natural fracturing to increase production. Some pop-ups are as shallow as 800 feet and because of over pressuring have been drilled and completed using air to deal with substantial flow rates.

The geophysical techniques that the Corporation has developed work well in locating AltaCanada’s drilling targets and have kept the Corporation’s success ratios high.

Drilling cost control is important to shallow gas plays. Although the Corporation’s costs to drill and case to 1,200 feet depth have increased with increased costs for steel and cement, AltaCanada still averages US$125,000 per cased well.

Prior to 2010, most of the Corporation’s activities have been directed to the shallow Eagle formation. AltaCanada’s extensive seismic shooting, although initially focused on the shallow gas drilling, these same data, followed up by a successful 3-D program, have identified drillable oil targets in the Jurassic Sawtooth (Shaunavon formation).

The Jurassic oil targets are at about 4200 feet and cost approximately $450K to drill and case. This zone produces from other pools in the area having initial productivities in the 200b/d to 400b/d.

In addition, two wells that were drilled and abandoned in the early 1950’s, encountered what appears to be porosity, permeability and resistivity in the middle Bakken at 4800 feet. While these data are based on old, poorer quality logs the Bakken objective, although of high risk has a huge potential of several hundred million barrels if successful. The Bakken zone produces extensively in eastern Montana, in Richland County, and has recently been discovered in Glacier County to the west. A vertical well to test this objective would cost approximately $600K.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

This statement of reserves data and other information is dated March 22, 2010 and is effective December 31, 2009. The preparation date of the information regarding reserves in this Statement and of the GLJ Report was March 22, 2010.
Below are tables detailing reserve data by country and by hydrocarbon type. Pages 9 through 10 are corporate totals. Pages 11 through 12 are United States reserves only and pages 13 through 14 are Canadian reserves only.

The future net revenue numbers presented throughout this Statement, whether calculated without discount or using a discount rate, are estimated values and do not necessarily represent fair market value.

Disclosure of Reserves Data

The following reserves data and associated tables summarize the reserves of crude oil, natural gas and associated products and the net present values of future net revenues associated with the Corporation's reserves as evaluated in the GLJ Report, based on forecast price assumptions presented in accordance with NI 51-101.
The tables summarize the data contained in the GLJ Report and, as a result, may contain slightly different numbers than the GLJ Report due to rounding. There is no assurance that the price and cost assumptions set out below will be attained and variances could be material. The reserve estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual recovered reserves may be greater than or less than the estimates provided herein.

NI 51-101 requires that issuers engaged in oil and gas activities report their reserves on a “gross” and “net” basis as those terms are defined in the Canadian Oil and Gas Evaluation Handbook (the “**COGE Handbook**”). See “Statement of Reserves Data And Other Oil And Gas Information – Definitions, Notes And Other Cautionary Statements” in this AIF.
All of the Corporation's reserves and production are located in the province of Alberta, Canada and the state of Montana, U.S.

Aggregate Data

The following tables detail the aggregate gross and net reserves of the Corporation, as at December 31, 2009 using forecast prices and costs as well the aggregate net present value of future net revenue attributable to the reserves estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves
Forecast Prices and Costs
As at December 31, 2009

	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
PROVED								
Developed Producing	4	4	10	10	3,172	2,614	-	-
Developed Non-Producing	-	-	-	-	1,249	1,036	-	-
Undeveloped	-	-	-	-	1,696	1,422	-	-
TOTAL PROVED	4	4	10	10	6,117	5,072	1	-
PROBABLE	1	1	4	4	5,730	4,655	-	-
TOTAL PROVED PLUS PROBABLE	5	5	14	14	11,847	9,727	1	-

Net Present Values of Future Net Revenues
Forecast Prices and Costs
As at December 31, 2009

	Before Income Taxes Discounted at (%/year) [1]				
Reserves Category	0% ($thousands)	5% ($thousands)	10% ($thousands)	15% ($thousands)	20% ($thousands)
PROVED					
Developed Producing	8,932	7,071	5,897	5,081	4,480
Developed Non-Producing	2,729	2,221	1,841	1,551	1,326
Undeveloped	2,861	1,891	1,273	869	598
TOTAL PROVED	14,522	11,183	9,011	7,501	6,404
PROBABLE	14,598	9,296	6,259	4,411	3,229
TOTAL PROVED PLUS PROBABLE	29,120	20,479	15,270	11,912	9,633

	After Income Taxes Discounted at (%/year) [1]				
Reserves Category	0% ($thousands)	5% ($thousands)	10% ($thousands)	15% ($thousands)	20% ($thousands)
PROVED					
Developed Producing	8,932	7,071	5,897	5,081	4,480
Developed Non-Producing	2,729	2,221	1,841	1,551	1,326
Undeveloped	2,861	1,891	1,273	869	598
TOTAL PROVED	14,522	11,183	9,011	7,501	6,404
PROBABLE	14,598	9,296	6,259	4,411	3,229
TOTAL PROVED PLUS PROBABLE	29,120	20,479	15,270	11,912	9,633

The following tables provide (i) a breakdown of various elements of aggregate future net revenue attributable to proved reserves and proved plus probable reserves of the Corporation estimated using both constant prices and costs and forecast prices and costs and calculated without discount, and (ii) the volume of aggregate production of the Corporation estimated for 2010:

Total Future Net Revenue
As at December 31, 2009
and Estimated Production for 2010

($thousands)	Forecast Prices (Undiscounted) Proved Reserves	Proved plus Probable Reserves
Revenue	48,986	98,184
Royalties & Mineral Tax	7,423	16,129
Operating costs	21,022	40,712
Operating Income	20,543	41,343
Development costs	4,623	10,217
Abandonment and reclamation costs	1,398	2,006
Future net revenue before income tax	14,522	29,120
Future income tax expense	-	-
Future net revenue after income tax	14,522	29,120
2010 Production (Gross)		
Light and Medium Oil (bbl/d)	1	1
Heavy Oil (bbl/d)	6	6
Gas (mcf)	1,657	1,809
NGL (bbl/d)	-	-
BOE (bbl/d)	283	309
2010 Production (Net)		
Light and Medium Oil (bbl/d)	1	1
Heavy Oil (bbl/d)	6	6
Gas (mcf)	1,364	1,483
NGL (bbl/d)	-	-
BOE (bbl/d)	233	254

Note:

(1) Montana production represents more than 20% of the Corporation's total production and is shown separately under US Data.

US Data

The following tables detail the gross and net US reserves of the Corporation, as at December 31, 2009, using forecast prices and costs as well the net present value of future net revenue attributable to the reserves estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of US Oil and Gas Reserves
Forecast Prices and Costs
As at December 31, 2009

	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Reserves Category	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mmcf)	(mmcf)	(mbbl)	(mbbl)
PROVED								
Developed Producing	-	-	-	-	2,228	1,780	-	-
Developed Non-Producing	-	-	-	-	804	643	-	-
Undeveloped	-	-	-	-	1,041	802	-	-
TOTAL PROVED	-	-	-	-	4,073	3,225	-	-
PROBABLE	-	-	-	-	4,763	3,790	-	-
TOTAL PROVED PLUS PROBABLE	-	-	-	-	8,836	7,015	-	-

Net Present Values of Future Net Revenues
Forecast Prices and Costs
As at December 31, 2009

	Before Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
Reserves Category	($thousands)	($thousands)	($thousands)	($thousands)	($thousands)
PROVED					
Developed Producing	3,874	3,202	2,724	2,371	2,103
Developed Non-Producing	1,958	1,628	1,378	1,187	1,036
Undeveloped	2,003	1,396	1,003	738	555
TOTAL PROVED	7,835	6,226	5,105	4,296	3,694
PROBABLE	10,624	6,674	4,398	3,021	2,149
TOTAL PROVED PLUS PROBABLE	18,459	12,900	9,503	7,317	5,843

	After Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
Reserves Category	($thousands)	($thousands)	($thousands)	($thousands)	($thousands)
PROVED					
Developed Producing	3,874	3,202	2,724	2,371	2,103
Developed Non-Producing	1,958	1,628	1,378	1,187	1,036
Undeveloped	2,003	1,396	1,003	738	555
TOTAL PROVED	7,835	6,226	5,105	4,296	3,694
PROBABLE	10,624	6,674	4,398	3,021	2,149
TOTAL PROVED PLUS PROBABLE	18,459	12,900	9,503	7,317	5,843

The following tables provide (i) a breakdown of various elements of future net revenue attributable to proved US reserves and proved plus probable US reserves of the Corporation estimated using forecast prices and costs and calculated without discount, and (ii) the volume of production of the Corporation estimated for 2010:

Total Future Net Revenue
As at December 31, 2009
and Estimated Production for 2010

	Forecast Prices (Undiscounted)	
($thousands)	Proved Reserves	Proved plus Probable Reserves
Revenue	29,869	69,544
Royalties & Mineral Tax	6,188	14,239
Operating costs	13,246	28,926
Net Production Revenue	10,436	26,378
Development costs	1,893	6,723
Abandonment and reclamation costs	707	1,196
Future net revenue before tax	7,835	18,459
Future income tax expense	-	-
After tax cash flow	7,835	18,459
2010 Production (Gross)		
Light and Medium Oil (bbl/d)	-	-
Heavy Oil (bbl/d)	-	-
Gas (mcf/d)	1,154	1,253
NGL (bbl/d)	-	-
BOE (boe/d)	192	209
2010 Production (Net)		
Light and Medium Oil (bbl/d)	-	-
Heavy Oil (bbl/d)	-	-
Gas (mcf/d)	929	1,012
NGL (bbl/d)	-	-
BOE (boe/d)	156	168

Canada Data

The following tables detail the gross and net Canadian reserves of the Corporation, as at December 31, 2009, using forecast prices and costs as well the aggregate net present value of future net revenue attributable to the reserves estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves
Forecast Prices and Costs
As at December 31, 2009

	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
PROVED								
Developed Producing	4	4	10	10	945	834	-	-
Developed Non-Producing	-	-	-	-	445	393	-	-
Undeveloped	-	-	-	-	655	621	-	-
TOTAL PROVED	4	4	10	10	2,044	1,847	1	-
PROBABLE	1	1	4	4	966	865	-	-
TOTAL PROVED PLUS PROBABLE	5	5	14	14	3,011	2,712	1	-

Net Present Values of Future Net Revenues
Forecast Prices and Costs
As at December 31, 2009

	Before Income Taxes Discounted at (%/year)				
Reserves Category	0% ($thousands)	5% ($thousands)	10% ($thousands)	15% ($thousands)	20% ($thousands)
PROVED					
Developed Producing	5,057	3,869	3,173	2,710	2,376
Developed Non-Producing	772	593	462	364	290
Undeveloped	858	496	271	131	43
TOTAL PROVED	6,687	4,957	3,906	3,205	2,709
PROBABLE	3,974	2,622	1,861	1,390	1,080
TOTAL PROVED PLUS PROBABLE	10,661	7,579	5,767	4,595	3,789

	After Income Taxes Discounted at (%/year)				
Reserves Category	0% ($thousands)	5% ($thousands)	10% ($thousands)	15% ($thousands)	20% ($thousands)
PROVED					
Developed Producing	5,057	3,869	3,173	2,710	2,376
Developed Non-Producing	772	593	462	364	290
Undeveloped	858	496	271	131	43
TOTAL PROVED	6,687	4,957	3,906	3,205	2,709
PROBABLE	3,974	2,622	1,861	1,390	1,080
TOTAL PROVED PLUS PROBABLE	10,661	7,579	5,767	4,595	3,789

The following tables provide (i) a breakdown of various elements of future net revenue attributable to proved Canadian reserves and proved plus probable Canadian reserves of the Corporation estimated forecast prices and costs and calculated without discount, and (ii) the volume of production of the Corporation estimated for 2010:

Total Future Net Revenue
As at December 31, 2009
and Estimated Production for 2010

	Forecast Prices (Undiscounted)	
($thousands)	Proved Reserves	Proved plus Probable Reserves
Revenue	19,117	28,640
Royalties & Mineral Tax	1,234	1,890
Operating costs	7,776	11,785
Net Production Revenue	10,107	14,964
Development costs	2,729	3,494
Abandonment and reclamation costs	691	810
Future net revenue before tax	6,687	10,661
Future income tax expense	-	-
After tax cash flow	6,687	10,661
2010 Production (Gross)		
Light and Medium Oil (bbl/d)	1	1
Heavy Oil (bbl/d)	6	6
Gas (mcf/d) [(1)]	503	556
NGL (bbl/d)	-	-
BOE (boe/d)	91	100
2010 Production (Net)		
Light and Medium Oil (bbl/d)	1	1
Heavy Oil (bbl/d)	6	6
Gas (mcf/d) [(1)]	435	471
NGL (bbl/d)	-	-
BOE (boe/d)	80	86

Note:

(1) Viking Kinsella and Cardiff are the only fields which, individually, represent more than 20% of the Corporation's Canadian gas production. Future proven production from Viking Kinsella for 2010 is 110 mmcf gross and 95 mmcf net. Future production from Cardiff for 2010 is 55 mmcf gross and 46 mmcf net.

Aggregate Revenue by Production Group

The following table details by production group the aggregate net present value of future net revenue of the Corporation (before deducting future income tax expenses) estimated using forecast prices and costs and calculated using a discount rate of 10%.

Future Net Revenue
By Production Group
As at December 31, 2009

Reserves Category	Production Group	Future Net Revenue before Income Taxes[3] (discounted at 10%/year) Forecast prices and costs ($thousands)
Proved	Light and Medium Oil[1]	205
	Heavy Oil	491
	Natural Gas[2]	22,289
		22,986
Total Proved plus Probable	Light and Medium Oil[1]	228
	Heavy Oil	629
	Natural Gas[2]	38,274
		39,131

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas from oil wells.
(3) Other company and revenue and costs not related to a specific production group have been allocated proportionately to production groups.

Pricing Assumptions

The following tables detail the benchmark reference prices for the regions in which the Corporation operated as at December 31, 2009 reflected in the reserves data disclosed above under "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data". The forecast cost and price assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating and capital costs. In addition, operating and capital costs have not been increased on an inflationary basis. These pricing assumptions were provided by GLJ.

Summary of Pricing and Inflation Rate Assumptions
As at December 31, 2009
Forecast Prices and Costs

	OIL					EDMONTON LIQUIDS PRICES				
Year	WTI Cushing ($US/bbl)	Edmonton Reference ($CDN/bbl)	Hardisty 25^{O} ($CDN/bbl)	Cromer 29^{O} ($CDN/bbl)	NATURAL GAS AECO Monthly Index ($CDN/mmbtu)	Pentanes ($CDN/bbl)	Butane ($CDN/bbl)	Propane ($CDN/bbl)	Inflation Rate %/Year	Exchange Rate ($US/$CDN)
Forecast:										
2010	80.00	83.26	71.61	76.60	5.96	84.93	64.11	52.46	2.0	0.950
2011	83.00	86.42	72.59	78.64	6.79	88.15	66.54	54.45	2.0	0.950
2012	86.00	89.58	73.45	80.62	6.89	91.37	68.98	56.43	2.0	0.950
2013	89.00	92.74	74.19	82.54	6.95	94.59	71.41	58.42	2.0	0.950
2014	92.00	95.90	76.72	85.35	7.05	97.82	73.84	60.42	2.0	0.950
2015	93.84	97.84	78.27	87.07	7.16	99.79	75.33	61.64	2.0	0.950
2016	95.72	99.81	79.85	88.83	7.42	101.81	76.85	62.88	2.0	0.950
2017	97.64	101.83	81.46	90.63	7.95	103.86	78.41	64.15	2.0	0.950
2018	99.59	103.88	83.11	92.46	8.52	105.96	79.99	65.45	2.0	0.950
2019	101.58	105.98	84.78	94.32	8.69	108.10	81.60	66.77	2.0	0.950
Thereafter	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	2.0	0.950

In Canada the Corporation's weighted average prices received in 2009 were $44.71/bbl for oil, and $4.19/mcf for natural gas. The Corporation’s light and medium oil production is negligible.

In the US, the Corporation’s weighted average price received in 2009 was $3.39/mcf for natural gas.

Reconciliations of Changes in Reserves and Future Net Revenue

The following table outlines the reconciliation of changes in the net reserves estimates for the Corporation for the period December 31, 2008 to December 31, 2009 using forecast prices and costs for its Canadian properties.

Reconciliation of Changes in Net Canadian Oil and Gas Reserves
Forecast Prices and Costs
As at December 31, 2009

	Light & Medium Oil			Heavy Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
Factors	Proved (mbbl)	Probable (mbbl)	Prove Plus Probable (mbbl)	Proved (mbbl)	Probable (mbbl)	Prove Plus Probable (mbbl)	Proved (mmcf)	Probable (mmcf)	Prove Plus Probable (mmcf)	Proved (mbbl)	Probable (mbbl)	Prove Plus Probable (mbbl)
December 31,2008	2	1	3	6	3	9	2,555	1,009	3,564	1	-	1
Extensions &	-	-	-	-	-	-				-	-	-
Improved Recovery	-	-	-			-				-	-	-
Technical Revisions	-	-	-	2	2	4	(283)	(23)	(306)		-	
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(2)	(1)	(3)	3	-	3	(50)	(28)	(78)	-	-	-
Production	-	-	-	(1)	-	(1)	(212)	-	(212)	-	-	-
December 31, 2009	-	-	-	10	4	14	2,009	958	2,968	1	-	1

The following table outlines the reconciliation of changes in the net reserves estimates for the Corporation for the period December 31, 2008 to December 31, 2009 using forecast prices and costs for its US properties.

Reconciliation of Changes in Net US Oil and Gas Reserves
Forecast Prices and Costs
As at December 31, 2009

	Light & Medium Oil			Heavy Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
Factors	Proved (mbbl)	Probable (mbbl)	Prove Plus Probable (mbbl)	Proved (mbbl)	Probable (mbbl)	Prove Plus Probable (mbbl)	Proved (mmcf)	Probable (mmcf)	Prove Plus Probable (mmcf)	Proved (mbbl)	Probable (mbbl)	Prove Plus Probable (mbbl)
December 31,2008	-	-	-	-	-	-	7,399	6,043	13,442	-	-	-
Extensions &	-	-	-	-	-	-				-	-	-
Improved										-	-	-
Recovery	-	-	-	-	-	-	819	(358)	461			
Technical Revisions	-	-	-	-	-	-	(2287)	(957)	(3,244)	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	308	308	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	(569)	(322)	(891)	-	-	-
Production	-	-	-	-	-	-	(471)	-	(471)	-	-	-
December 31, 2009	-	-	-	-	-	-	4,073	4,763	8,836	-	-	-

Additional Information Relating to Reserves Data

Undeveloped Reserves

In general, proved undeveloped reserves are assigned on the basis that there is a 90% probability that the reserves can be developed within a calendar year, and probable undeveloped reserves are assigned on the basis that there is a 50% probability that the reserves may be developed within the next one or two years.

As at December 31, 2009, the net capital, as estimated in the GLJ report, to develop proved undeveloped reserves is $210,000 in 2010 and $1,096,000 in 2011. The estimated net capital expenditure for probable undeveloped reserves is $455,000 for 2010 and $553,000 for 2011. The 2010 estimated cash flow provides the financial ability to conduct some of this development and the Corporation has financing plans underway to provide the balance of capital to develop both proved undeveloped and probable undeveloped reserves, subject to improved gas prices.

Significant Factors or Uncertainties

For details of important economic factors or significant uncertainties that may affect the components of the reserves data in this Statement, see "Management's Discussion and Analysis" in the Corporation's Annual Report and “Forward Looking Statements And Other Cautionary Notes” and "Risk Factors" herein.

Future Development Costs

The following table details the development costs deducted in the estimation of future net revenue attributable to proved reserves of the Corporation (estimated using forecast prices and costs) and proved plus probable reserves of the Corporation (estimated using forecast prices and costs) for the Corporation's Canadian properties:

Future Development Costs
Canadian Reserves
($thousands)

	Proved Reserves (Forecast prices and costs)	Proved plus Probable Reserves (Forecast prices and costs)
2010	25	84
2011	801	801
2012	-	523
2013	302	395
2014	1,539	1,539
Remainder	62	152
Total Undiscounted	2,729	3,494
Total Discounted at 10%	1,972	2,523

The following table details the development costs deducted in the estimation of future net revenue attributable to proved reserves of the Corporation (estimated using forecast prices and costs) and proved plus probable reserves of the Corporation (estimated using forecast prices and costs) for the Corporation's US properties:

Future Development Costs
US Reserves
($thousands)

	Proved Reserves (Forecast prices and costs)	Proved plus Probable Reserves (Forecast prices and costs)
2010	184	581
2011	295	848
2012	988	1,327
2013	128	1,345
2014	190	1,238
Remainder	107	1,384
Total Undiscounted	1,893	6,723
Total Discounted at 10%	1,478	4,913

The Corporation's source of funding for future development costs of the Corporation's reserves will be derived from a combination of cash flow, debt and new equity. Management of the Corporation does not anticipate that the costs of funding referred to above will materially affect the Corporation's disclosed reserves and future net revenues or will make the development of any of the Corporation's properties uneconomic.

Oil and Gas Properties and Location of Production

Acquisition, exploitation and exploration activities have resulted in AltaCanada having significant interests and assets in the following areas of Alberta and Montana. Reserve amounts are gross reserves based on constant cost and price assumptions as evaluated in the GLJ Report. Information in respect of gross and net acres, well counts and production is as at December 31, 2009, except where otherwise indicated.

Viking Kinsella, Alberta

AltaCanada controls interests averaging 29 percent in 26,807 acres at Viking Kinsella, including over 38 producing wells and a 58.4 percent interest in a gas processing facility and varying interests between 44.5 percent and 49.5 percent in an extensive gas gathering system.

Three wells were drilled on the property during 2007 by a third party as part of a multi-well drilling program on the acreage to be completed at no cost to the Corporation.

In late 2008, AltaCanada participated as to a 40.2% working interest in the tie-in of a previously suspended gas well.

AltaCanada continues to evaluate a 25 percent working interest well drilled in 2003 in the northern portion of this property that set up a Sparky oil development project. Although the well also tested 700 mcf/d from the Lloydminster sand, below the Sparky zone, difficulty in putting the well on production was caused by heavy oil produced in association with the gas. Remedial measures, including the installation of a bottom hole progressive cavity pump, were not successful and the well was re-completed into the Sparky oil zone in early 2007. Subject to favourable oil prices, seismic, logs and offset well data support a potential for an 11 well infill development program to exploit the heavy Sparky oil.

Killam, Alberta

AltaCanada owns varying interests in 29,000 (2,439 net) acres at Killam including an average working interest of 16.8 percent in about 8,300 acres and royalty interests ranging from 2.1 to 8.4 percent in other acreage. Several additional locations remain to be drilled on the property and we believe there is significant potential to increase our production with infill locations combined with well stimulation programs.

In 2008, AltaCanada assumed an additional 66.35% working interest in a suspended Viking gas well. Testing and potential tie-in of this well is planned for mid 2010.

Cardiff, Alberta

AltaCanada owns an average 42 percent interest in 6,080 acres (2,537 net) at Cardiff. A seismic option was granted to one operator which resulted in a multi-zone gas well which commenced drilling in late December 2006 and was completed in early 2007. AltaCanada's interest is an overriding royalty of 5.8 percent. A second well, in which AltaCanada has a 7.5% GORR was drilled in the second quarter and completed as a gas well in early 2008. No activity on this property occurred in 2009 and none is proposed for 2010.

Blaine County, Montana

AltaCanada operates in Montana through ML&E. Its acreage is located 25 miles south of the Canadian border and is offset to the northwest by the Battle Creek field operated by Helis and the Omimex Group and to the west by the Tiger Ridge field operated by Devon Energy Corporation. Although on trend with these fields, ML&E's acreage blocks originate from multiple landowners and are largely unexplored utilizing any modern gravity or seismic data and have had very little previous drilling activity.

To support its drilling program, ML&E has focused its efforts, beginning in 2003, on conducting regional gravity surveys and shooting seismic over identified gravity anomalies, initially seeking prospects in the shallow Eagle sands. Secondary deeper Jurassic prospects will be pursued by the Corporation in subsequent programs. A regional gravity survey covering sixteen townships was completed in December 2003 defining structural trends over two-thirds of that area.

Full cycle exploration is a 3-year project starting from a geologic concept; acquiring a land base, confirming geologic concepts with geophysics, drilling the first wells, then confirming threshold reserves to support construction of a pipeline and infrastructure.

AltaCanada completed its first land deal in March 2003 through ML&E. First gas flowed in July 2004 with a significant increase on October 1, 2004. Optimization of the defined pools, adding compression to our delivery system and stepping out to explore the balance of our huge block were accomplished from 2005 to 2009.

To date AltaCanada's exploration success has come from the Eagle formation. This horizon traps the up-faulted or "pop-up" features and on "regional" forms traps in unfractured rocks against these same fault structures. Flow rates from the "pop-up" traps are greater because of natural fracturing, albeit over smaller areas. The regional traps have presented lower flow rates but the two larger regional accumulations identified to date cover significantly larger areas, 6 and 12 square miles. In August 2004, a 160 acre down-spacing application was approved to develop both of these pools (ie: 4 wells can be drilled/square mile).

Exploration and exploitation of this property was continued during 2007 with the drilling of 10 (5.8 net) wells, resulting in 8 (4.2 net) commercial gas wells.

Seismic activity and land acquisition continued, increasing the Corporation's geophysical database to 572 miles of 2-D seismic data and 2.3 square miles of 3-D seismic data. The Corporation's land base has since increased to 391,586 gross (289,809 net) acres, including 253,514 net acres of undeveloped lands.

The Corporation completed the construction of one six mile 6 inch and one two and three-quarter mile 4 inch pipeline during the third quarter of 2005. Gas production and sales commenced on October 1, 2004. Gas is currently sold at the Montana/Saskatchewan border at a sales price of AECO index less $0.09/GJ.

All of ML&E's gas is moved through three separate systems (Harlem, Zurich and Chinook) which gather, compress and transport gas north to the Canadian border for sale. In addition, the Corporation operates three field compressors to enhance productivity. During 2007, ML&E completed a new pipeline to interconnect the Zurich and Harlem systems. This new line allows the gas to flow through either system or a combination thereof and provides the operational flexibility to reduce downtime should one system or the other have restricted flow due to pipeline or compressor restrictions. The capacity provided by this interconnect and supplemented by new compression at Harlem installed in the first quarter of 2007, will support the flow requirements of upcoming infill drilling programs.

Only a portion of the potential pools were included as proven undeveloped or probable reserves. The management of the Corporation estimates that future drilling, particularly on Fort Belknap, will add both proven and proven undeveloped reserves. During 2008, activity was concentrated on exploring for and defining Eagle gas pools on the Fort Belknap Reservation, with the drilling of eight (4.2 net) wells resulting in six (3.1 net) gas wells.

In addition, several attractive Jurassic oil opportunities have been identified by seismic on AltaCanada's lands. Such zones, which are productive in nearby fields, are planned for exploration in 2010.

Progress was made on exploring a portion of the Fort Belknap Indian Reservation, located to the southeast of the Corporation's large acreage position. Five (2.7 net) wells were drilled on the Reservation during 2009, resulting in 5 (2.7 net) gas wells. In late 2008, approval was obtained from the Bureau of Land Management and the Bureau of Indian Affairs for the construction of a natural gas pipeline onto the Reservation. This project, completed in early 2009, encompassed over seven miles of steel and twenty-four miles of plastic pipe. First gas sales from Fort Belknap commenced on February 9, 2009.

Additional seismic is planned for 2010 to identify additional exploration targets on this large land base.

Producing and Non-Producing Wells

The following tables set forth the Corporation's gross and net working interests in crude oil and natural gas wells as at December 31, 2009, which are producing or capable of producing:

Alberta Wells

Light & Medium Oil		Heavy Oil		Natural Gas		Suspended		Service		Total	
Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
4	1	-	-	103	20	30	4	4	-	141	25

Montana Wells

Light & Medium Oil		Heavy Oil		Natural Gas		Suspended		Service		Total	
Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
-	-	-	-	84	74	35	27	-	-	119	101

Existing production delivers gas to the Battle Creek facility and into the Chinook pipeline but new tie-ins may utilize the Havre pipeline system. Both of these lines have available capacity and deliver gas north to Canada via the Many Islands Pipeline to the TransCanada Pipelines main line in Saskatchewan. An additional drilling program is planned in 2010 in Blaine County. See "Business of the Corporation – 2010 Activities".

Properties with no Attributed Reserves

The following table sets out the undeveloped land holdings of the Corporation as at December 31, 2009:

	Undeveloped	
	Gross	**Net**
Alberta	9,940	878
Montana	350,381	253,514

Of this acreage, approximately 30,624 net acres in Montana are due to expire during 2010. Extensions for additional terms can be signed for all expiring lands.

Forward Contracts

The Corporation uses derivative financial instruments to manage its commodity price exposure. Financial instruments realized in the year ended December 31, 2009 are:

Natural Gas Hedges

Volume (GJ/day)	*$/GJ*	*Term*	*Gain (Loss) Realized Year Ended December 31, 2009*
1,000	$ 6.00	February 2009 to December 2009	$ 768,100
500	$ 4.32	April 2009 to October 2009	121,998
500	$ 5.00	November 2009 to March 2010	12,710
Total			**$ 902,808**

At December 31, 2009 the Corporation has the following derivative financial instruments outstanding.

1,000 GJ/day call option at $7.40/GJ January 2010 to December 2010
1,000 GJ/day forward sale at $5.42/GJ April 2010 to March 2011
500 GJ/day collar at $5.00/GJ and $7.00/GJ to March 2010

The mark to market value of these hedges outstanding at December 31, 2009 was a financial derivative liability of $147,636.

Additional Information Concerning Abandonment and Reclamation

The Corporation bases its estimates for the costs of abandonment and reclamation of surface leases, wells, facilities and pipelines on previous experience of management with similar well sites and facility locations. As at December 31, 2009, management expected to incur such costs on 123 net wells. The total of such costs, net of estimated salvage value, was $2,006,000 (undiscounted) and $635,000 (discounted at 8%). Future net revenue figures set forth in this Statement only include abandonment liabilities for wells assigned reserves. Within the next three financial years, it is expected such costs will total approximately $222,000.

Tax Horizon

The income taxes deducted in the calculation of future net revenue above assume a blow down scenario whereby the Corporation produces out its existing reserves. Under this scenario, the Corporation would be taxable in Canada in 2010 and in the US in 2020. The Corporation forecasts its tax horizon assuming a continuing business model whereby it reinvests cash flow at historic capital efficiencies in order to achieve minimum production and reserve growth. The results are dependent upon commodity prices and capital spending levels.

Costs Incurred

For the year ended December 31, 2009, the Corporation incurred the following costs on its properties:

Costs Incurred
Year Ended December 31, 2009
($)

	Canada	United States	Total
Property Acquisition Costs			
Proved Properties	-	-	-
Unproved Properties	8,459	779,740	788,199
Exploration Cost	172,556	181,601	354,157
Development Cost	62,448	1,537,729	1,600,177
Corporate	72,428	-	71,428
	314,891	2,499,070	2,813,961

Exploration and Development Activities

The following table summarizes the gross and net exploratory and development wells the Corporation has drilled, or has participated in for the year ended December 31, 2009:

	2009	
	Gross	Net
Canada		
Exploratory Oil wells	-	-
Developmental Oil wells	-	-
Exploratory Gas wells	-	-
Developmental Gas wells	-	-
Service wells	-	-
Dry wells		
Total Canada	-	-
US		
Exploratory Oil wells	-	-
Developmental Oil wells	-	-
Exploratory Gas wells	5.0	2.7
Developmental Gas wells	-	-
Service wells	-	-
Dry wells	-	-
Total US	5.0	2.7

Production History

The following table summarizes AltaCanada's average daily working interest share of production, before royalties, of light and medium oil, heavy oil and natural gas for the periods indicated for its Canadian Properties:

	2009	**Q4**	**Q3**	**Q2**	**Q1**
Oil & NGL(bbls/d)	5	5	9	6	5
Natural Gas (mcf/d)	606	533	551	667	675
Total (boe/d)	106	94	101	117	117

The following table summarizes AltaCanada's average daily working interest share of production, before royalties, of light and medium oil, heavy oil and natural gas for the periods indicated for its US Properties:

	2009	Q4	Q3	Q2	Q1
Oil & NGL (bbls/d)	-	-	-	-	-
	-	-	-	-	-
Natural Gas (mcf/d)	1,290	1,050	1,367	1,337	1,407
Total (boe/d)	215	175	228	223	235

Notes:

(1) Quarterly production volumes may vary from amounts previously disclosed due to subsequent adjustments for the related production months.

(2) NGL, light and medium oil production is negligible, constituting less than one half of one percent of total production and is grouped with heavy oil amounts.

Netback History

The following table sets forth information respecting average net product prices received, royalties paid, operating expenses and netbacks received by the Corporation in respect of the Corporation's production of light and medium oil, heavy oil and natural gas in Canada for the periods indicated:

	2009	Q4	Q3	Q2	Q1	2008	Q4	Q3	Q2	Q1
Product Prices										
Light & Medium Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil ($/bbl)	44.71	55.40	26.75	38.24	23.52	57.86	36.91	92.36	55.90	54.95
Natural Gas($/mcf)	4.19	4.60	3.14	3.57	5.34	8.34	6.54	8.41	10.36	8.12
Net Royalties										
Light & Medium Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil ($/bbl)	4.54	2.91	0.22	0.76	14.13	4.89	2.79	3.97	2.43	10.35
Natural Gas($/mcf)	0.52	0.57	0.35	0.55	0.60	1.32	0.11	1.83	1.96	1.43
Operating Expense										
Light & Medium Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil ($/bbl)	13.26	11.21	7.53	11.93	12.43	13.70	18.62	14.16	13.54	8.56
Natural Gas($/mcf)	3.19	4.87	2.55	2.62	2.95	2.53	3.95	3.33	1.78	1.10
Operating Netback										
Light & Medium Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil ($/bbl)	26.91	41.28	19.00	25.55	(3.04)	39.37	15.50	74.23	39.93	36.04
Natural Gas($/mcf)	0.48	(0.84)	0.24	0.40	1.79	4.49	2.48	3.25	6.62	5.59

Notes:

(1) Revenue is product price excluding hedging gains.

(2) Operating expense is comprised of petroleum and surface lease rental costs, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems.

(3) NGL, light and medium oil amounts are negligible and are grouped with heavy oil amounts.

(4) Columns may not add due to rounding.

The following table sets forth information respecting average net product prices received, royalties paid, operating expenses and netbacks received by the Corporation in respect of the Corporation's production of light and medium oil, heavy oil and natural gas in Montana for the periods indicated.

	2009	Q4	Q3	Q2	Q1	2008	Q4	Q3	Q2	Q1
Product Prices										
Light & Medium Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Natural Gas($/mcf)	3.39	2.05	2.97	3.33	4.87	8.15	6.58	7.70	10.84	7.53
Net Royalties										
Light & Medium Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Natural Gas($/mcf)	0.97	0.84	0.76	0.89	1.36	2.26	1.84	2.14	2.99	2.07
Operating Expense										
Light & Medium Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Natural Gas($/mcf)	2.35	1.62	1.90	2.41	3.29	2.24	3.12	1.97	2.21	1.92
Operating Netback										
Light & Medium Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil ($/bbl)	-	-	-	-	-	-	-	-	-	-
Natural Gas($/mcf)	0.07	(0.41)	0.31	0.03	0.22	3.65	1.62	3.59	5.64	3.54

Notes:

(1) Operating expense is comprised of petroleum and surface lease rental costs, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems.

(2) NGL, light and medium oil amounts are negligible and are grouped with heavy oil amounts

(3) Columns may not add due to rounding.

(4) All in Canadian Dollars.

Definitions, Notes and Other Cautionary Statements

In the tables set forth in this Statement and elsewhere in this Annual Information Form, unless otherwise indicated, the following definitions and other notes are applicable.

1. "***Gross***" means:

   (a) in relation to the Corporation's interest in production and reserves, its "gross revenues", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

   (b) in relation to wells, the total number of wells in which the Corporation has an interest; and

   (c) in relation to properties, the total area of properties in which the Corporation has an interest.

2. "***Net***" means:

(a) in relation to the Corporation's interest in production and reserves, its "net reserves", which are the Corporation's interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interest in production of reserves;

(b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

3. *Definitions used for reserve categories are as follows:*

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

<u>Development and Production Status</u>

Each of the reserve categories (proved plus probable) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be s ubdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

- at least a 50 percent probability that the quantities recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. *Forecast prices and costs*

Future prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

5. *ARTC*

ARTC is included in the cumulative cash flow amounts, ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995.

6. *Future income tax expense*

Future income tax expenses are estimated:

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

7. ***"Development well"*** means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic location horizon known to be productive.

8. ***"Development costs"*** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

9. ***"Exploration well"*** means a well that is not a development well, a service well or a stratigraphic test well.

10. ***"Exploration costs"*** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

11. ***"Service well"*** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

12. Numbers may not add due to rounding.

13. The estimates of future net revenue presented do not represent fair market value.

14. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

15. Estimated future abandonment and reclamation costs related to a property have been taken into account by GLJ in determining reserves that should be attributable to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs.

16. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

17. All factual data supplied to GLJ was accepted by them as represented. No field inspection was conducted.

DIRECTORS AND OFFICERS OF THE CORPORATION

The following table sets forth the names and municipalities of residence of all directors and executive officers of the Corporation, their positions and offices within the Corporation, their principal occupations during at least the last five years, the date each director became a director of the Corporation and the approximate number of Common Shares beneficially owned, or controlled or directed, directly or indirectly, by each of them, as at the date hereof.

Name and Municipality of Residence	Position Held and Date of Appointment as Director	Principal Occupations	Number and [11] Percentage of Common Shares
Charles V. Selby[4] Calgary, Alberta	Chairman and Director since 1997	Chairman and Director of the Corporation; President of Caledonian Royalty Corp., Director of Vecta Energy Corporation; Director of the Qwest Energy Group of Companies, NXT Energy Services Inc., Bridge Resources Corp., and Wellpoint Systems Inc.	1,591,093 [2] / 2.1%
Donald E. Foulkes Calgary, Alberta	President, Chief Executive Officer and Director since 2002	President, CEO and Director of the Corporation; Director of Second Wave Petroleum Ltd.., and Quadrise Canada; CEO and Chairman of Bushmills Energy Corp. (2001 to 2002); CEO and Chairman of Causeway Energy Corp. (1998 to 2001).	2,368,879/ 3.2%[5]
Michael J. Hibberd[1] [2] [3] Calgary, Alberta	Director since 1997	President of MJH Services Ltd. (Corporate Finance Advisors) (1995 to present); Chairman of Heritage Oil PLC and Canacol Energy; Director of Avalite Inc., Zapata Energy Corporation, Iteration Energy Corp and Pan Orient Energy Corp.	570,000 / 0.8% [6]
John R. Moore[1] [2] [3] Calgary, Alberta	Director since 1997	President of J.R. Moore and Associates Ltd. (1998 to present).	300,000 / 0.4%[7]
James W. Collins[1] [2] [3] McAllen, Texas	Director since 2007	Chairman of Rioco Corp. (1983-present); President of Mayfair Properties LLC. (1980-present) Corporate Secretary and Assistant Vice President, Sunshine Mining Company (1977-1980). Mr. Collins presently serves on several Boards of Directors of several corporations and institutions, and was previously on the Board of both Causeway Energy Corp., and Bushmills Energy Corp.	15,576,591[8] / 20.7%
Donald L. Jackson Calgary, Alberta	Executive Vice President and Chief Operating Officer	Executive Vice President and COO of the Corporation since 2001; Independent Management and Petroleum Consultant (December 1997 to present).	990,479[9] [10] / 1.3%
Brian A. Page Calgary, Alberta	Vice President, Finance and Chief Financial Officer	Vice President, Finance and CFO of the Corporation since May 2008; Controller, of the Corporation, July 2006 to April 2008; Controller Churchill Energy Corp., February 2005 to June 2006.	326,979[11] / 0.4%

Notes:

(1) *Member of the Audit Committee. The Corporation does not have an Executive Committee.*
(2) *Member of the Compensation Committee.*
(3) *Member of the Reserves Committee.*
(4) *Mr. Selby holds options exercisable for the purchase of 363,333 additional shares.*
(5) *Mr. Foulkes holds exercisable options for the purchase of 363,333 additional shares.*
(6) *Mr. Hibberd holds options exercisable for the purchase of 338,333 additional shares.*
(7) *Mr. Moore holds options exercisable for the purchase of 368,333 additional shares.*
(8) *Mr. Collins holds options exercisable for the purchase of 188,333 additional shares.*
(9) *Includes 71,000 Common shares held by Mr. Jackson's spouse.*
(10) *Mr. Jackson holds options exercisable for the purchase of 288,333 additional shares.*
(11) *Mr. Page holds options exercisable for the purchase of 291,667 additional shares.*
(12) *As at March 31, 2010, the Corporation had 75,130,058 shares outstanding.*

The information as to the Common shares beneficially owned or over which control or direction is exercised, not being within the knowledge of the Corporation, has been furnished by the respective individuals.

As at the date hereof, the directors and executive officers of AltaCanada, as a group, beneficially own, or control or direct, directly or indirectly, 20,333,084 Common Shares or approximately 27.34% of the issued and outstanding Common Shares.

Orders

To the knowledge of management of the Corporation, no director or executive officer as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any company (including the Corporation), that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes hereof, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days.

Bankruptcies

Other than disclosed herein, to the knowledge of management of the Corporation, no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control thereof, (a) is, as at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr Michael J. Hibberd was an independent director of E-Zone Networks from 1998 to 2001. He resigned as a director within one year of E-Zone's Chapter 7 filing under the Federal Bankruptcy Code (United States). E-Zone Networks was a Delaware Corporation with no shares listed for trading, but it was a reporting issuer in Alberta. Further details can be found on the public record for E-Zone Networks at www.sedar.com. He was an independent director of Challenger Energy Corp. from December 1, 2005 until September 16, 2009. Challenger obtained a creditor protection order under the Companies' Creditors Arrangement Agreement providing for the acquisition by Canadian Superior Energy Inc. of Challenger (0.51 of a Canadian Superior common share for each Challenger common share). On September 17, 2009, all common shares of Challenger were exchanged for common shares of Canadian Superior and all creditor claims were fully honoured. Further details can be found on the public record for Challenger Energy at www.sedar.com.

Penalties and Sanctions

To the knowledge of management of the Corporation, no director or executive officer or shareholder holding a sufficient number of Common Shares to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority, or has been subject to any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject to in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial or director positions with other oil and natural gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation, In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Certain of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation.

PERSONNEL

As at December 31, 2009, AltaCanada had 9 full-time employees and 3 consultants in its Calgary office. Field operations are supported by contract operators located in close proximity to the production facilities.

DESCRIPTION OF SHARE CAPITAL

The following is the summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and Preferred Shares of the Corporation. No Preferred Shares are presently issued and outstanding.

Common Shares

The Common Shares rank junior to the Preferred Shares. Holders of Common Shares are entitled to one vote per share at meetings of shareholders, to receive such dividends as are declared by the Corporation and to receive the remaining property and assets of the Corporation upon its dissolution or winding up, subject to the rights of shares having priority.

Preferred Shares

The Preferred Shares are issuable in one or more series, and the directors may determine at the time of issuance the designation, rights, privileges, restrictions and conditions attaching to the shares of each series. Upon liquidation or winding up of the Corporation, the holders of Preferred Shares are entitled to such assets of the Corporation as are distributable to such shareholders, in priority to the Common Shares and all other shares ranking junior to the Preferred Shares. There are no Preferred Shares outstanding and no series of Preferred Shares have been authorized by the directors.

DIVIDEND POLICY

No dividends have been paid on the Common Shares of AltaCanada and the Corporation has no present intention to pay dividends. Any decision to pay dividends on its shares in the future will be made by the Board on the basis of the Corporation's earnings, financial requirements and other conditions at such time.

MARKET FOR SECURITIES

The Common shares are listed and posted for trading on the TSX-VE under the symbol "ANG".

PRICE RANGE AND TRADING VOLUME

The following table sets out the high and low closing prices and the volumes traded for the periods indicated on the TSX-VE.

		High	Low	Volume Traded
2009	January	0.125	0.055	385,000
	February	0.12	0.065	179,370
	March	0.105	0.065	376,964
	April	0.10	0.055	631,100
	May	0.10	0.08	212,700
	June	0.115	0.08	254,397
	July	0.08	0.075	122,700
	August	0.10	0.07	718,000
	September	0.08	0.06	201,900
	October	0.08	0.12	205,300
	November	0.08	0.65	732,614
	December	0.08	0.05	368,800

Note:

The closing price of the Common Shares on December 31, 2009, was $0.075. The closing price of the Common Shares on March 31, 2010 was $0.07.

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Competitive Conditions

All aspects of the oil and natural gas industry are highly competitive and AltaCanada actively competes with oil and natural gas and other companies, in particularly in the following areas: (i) exploration for and development of new sources of oil and natural gas reserves; (ii) reserve and property acquisitions; (iii) transportation and marketing of oil and natural gas and NGL; (iv) access to services and equipment to carry out exploration, development or operating activities; and (v) attracting and retaining experienced industry personnel. The oil and gas industry also competes with other industries focused on providing alternative forms of energy to consumers. Competitive forces can lead to cost increases or result in an oversupply of oil and natural gas, both of which could have a negative impact on financial results of the Corporation.

Environmental Protection

AltaCanada's operations are subject to government laws and regulations concerning pollution, protection of the environment and the handling and transport of hazardous materials. These laws and regulations generally require AltaCanada to remove or remedy the effect of activities on present and former operating sites, including dismantling production facilities and remediating damage caused by the use or release of specified substances. The Board reviews the environment policy and compliance with overall laws and regulations. Monitoring and reporting programs for environment, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation programs are in place and utilized to restore the environment.

AltaCanada expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2009, expenditures beyond normal compliance with environmental regulations were not material. AltaCanada does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2010. Based on our current estimate, the total anticipated undiscounted future cost of abandonment and reclamation costs to be incurred over the life of our reserves is estimated at $5.9 million.

Foreign Operations

As at December 31, 2009, all of AltaCanada's reserves and all of its production were located in North America, which limits AltaCanada's exposure to risks and uncertainties in countries considered politically and economically unstable. AltaCanada does not have operations and related assets outside of North America.

Alberta Royalties and Programs

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent. Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF range from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps are set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 40%.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from

5-50%, an increase from the previous maximum rates of 5-35%, and rate caps are set at $17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 36%.

Oil sands projects are also subject to the NRF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 m provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 m provides a sliding scale royalty credit based on depth of up to $3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

RISK FACTORS

The rights offering is the first step of additional financing that will be required to satisfy all commitments by July 31, 2010. Also, the Corporation has had discussions with several corporate entities with regard to a potential business combination or major recapitalization. This strategy will be actively pursued with the objective to complete a transaction by July 31, 2010.

The Corporation requires financing for working capital and the exploration and development of its properties. The Corporation’s continuance as a going concern is dependent upon its ability to obtain adequate financing and to reach profitable levels of operation. It is not possible to predict whether financing efforts will be successful or if the Corporation will attain profitable levels of operations. If the Corporation ceased to be a going concern, adjustments necessary to the recoverability and classification of recorded assets and liabilities could be material.

Oil and gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other participants in the search for the acquisition of oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil companies which have greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

The marketability of oil and natural gas acquired or discovered will be affected by numerous factors beyond the control of the Corporation. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government which may be amended from time to time. The Corporation's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Changes to such regulations may have a material adverse effect on the Corporation.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's net production revenue causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Corporation will in part be determined by their respective borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing bank credit available to them and could require that a portion of any bank debt outstanding be repaid.

The Corporation uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed for impairment to ensure that the carrying amount of these costs is recoverable based on expected future cash flows. To the extent that such capitalized costs (net of accumulated depreciation and depletion) less future taxes exceed the present value of estimated future net cash flows from the Corporation's proved oil and natural gas reserves, those excess costs would be required to be charged to operations.

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases.

From time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, the Corporation may not benefit from the fluctuating exchange rate.

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount which it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs that could have a material adverse affect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities. To the extent the Corporation is not the operator of its oil and gas properties, the Corporation is dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Although title reviews are done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation, which could result in a reduction of the revenue received by the Corporation.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserve and cash flow information set forth in this Annual Information Form represent estimates only. The reserves and estimated future net cash flow associated with the Corporation's properties have been independently evaluated effective December 31, 2009 by GLJ. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

From time to time the Corporation may enter into transactions to acquire assets or the shares of other Corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing which may not be available or, if available, may not be available on favourable terms.

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

The Corporation's success depends in large measure on certain key personnel. The loss of services of such key personnel could have a material adverse affect on the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

LEGAL PROCEEDINGS

The Corporation has no outstanding legal proceedings.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set out below, to the knowledge of the directors and officers of the Corporation, no director, executive officer, person or company that beneficially owns or exercises control or direction over Common shares carrying more than 10% of the voting rights attached to any class of voting shares of the Corporation or any associate or affiliate of the foregoing has had any material interest, direct or indirect, in any transactions within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

- Donald Foulkes, Michael Hibberd, James Collins, and Brian Page subscribed for $1,699,650 of the $2,174,650 convertible debentures issued June 27, 2008. Mr Collins subscribed for $1,000,000 of the convertible debentures issued May 12, 2009 and advanced $800,000 to the Corporation on November 30, 2009.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary and Toronto.

INTERESTS OF EXPERTS

GLJ prepared the GLJ Report referred to in this AIF. Neither GLJ nor any of its shareholders own any Common Shares.

The Corporation's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated April 16, 2010, in respect of the Corporation's consolidated financial statements with accompanying notes as at and for the years ended December 31, 2009 and 2008. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Corporation's information circular for its most recent annual meeting of security holders that involved the election of directors. Additional information is provided in the Corporation's financial statements and MD&A for its most recently completed financial year.

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the Board of Directors of AltaCanada Energy Corp. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves ad probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misscatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2009, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Locatioin of Reserves (Country or Foreign Geographic Area)	Net present value of the net reserves before income taxes			
			Realized	Evaluated	Reviewed	Final
	Corporate Summary					
GLJ Petroleum Consultants	March 23, 2010	Canada	-	5,767	-	5,767
GLJ Petroleum Consultants	March 23, 1010	U.S.	-	9,500	-	9,503
				15,270		15,870

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above.

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 30, 2010

Myron J. Hladyshovsky, P. Eng.
Vice-President

Report Of Management And Directors On Reserves Data And Other Information

FORM 51-101F3

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of AltaCanada Energy Corp. (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2009 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2009 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in the Annual Information Form of AltaCanada Energy Corp. effective as of December 31, 2009.

The Reserves Committee of the Board of Directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Board has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board has approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

"Donald E. Foulkes"

Donald E. Foulkes
President, Chief Executive Officer and Director

"Donald L. Jackson"

Donald L. Jackson
Executive Vice President and Chief Operating Officer

"Michael J. Hibberd"

Michael J. Hibberd
Director and Chairman of the Audit Committee

"Charles V. Selby"

Charles V. Selby
Director

Dated: April 15, 2010