



Montana Exploration Corp.
(formerly "AltaCanada Energy Corp.")

Annual Information Form

For the Year Ended December 31, 2011

April 30, 2012

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FORWARD LOOKING STATEMENTS

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:

- whether the Corporation will enter into a finalized extension agreements with Rioco and the terms thereof;
- 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 reserves and resources described exist in a quantity predicted or estimated and 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 are based on the Corporation's beliefs as of the date hereof. 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.

GLOSSARY

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

"2-D seismic data" means two-dimensional seismic data, being an interpretive data that allows a view of a vertical cross-section beneath a prospective area;

"3-D seismic data" means three-dimensional seismic data, being geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic data;

"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" means AltaCanada Energy Corp., the former name of Montana Exploration Corp.;

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

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

"Annual Information Form" or **"AIF"** means this annual information form of Montana Exploration dated April 30, 2012;

"ARTC" means the Alberta royalty tax credit;

"Audit Committee" means the audit committee of the Board.

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

"Bridge Loan Facility" means the loan agreement, as amended, entered into among Brookfield MEC, Selecta, the Partnership, ANG Holding, ANGUS and ML&E dated December 30, 2009;

"Brookfield" means Brookfield Bridge Lending Fund Inc.;

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

"Compensation Committee" means the compensation and governance committee of the Board;

"Consolidation" means the 10 for 1 consolidation of the Pre-consolidation Common Shares which occurred on February 25, 2011;

"Convertible Preferred Shares" means the Series A Preferred Shares, Series B Preferred Shares and Series C Preferred Shares;

"Fort Belknap Reservation" means the interests acquired by MEC in the oil and natural gas properties located on the Fort Belknap Indian Reservation located in Blaine, County, Montana.

"**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 on March 16, 2012 and effective December 31, 2011;

"**MEC**" or the "Corporation" means Montana Exploration Corp.

"**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 MEC and Selecta, pursuant to the laws of the Province of Alberta;

"**Pre-consolidation Common Shares**" means the Common Shares before the February 25, 2011 consolidation of the Common Shares on a ten for one basis;

"**Reserves Committee**" means the reserve committee of the Board;

"**Rights Letter**" means a rights letter dated March 19, 2010 wherein ANG Partners, Ltd. committed to subscribe for a minimum of 71,714,286 Pre-consolidation Common Shares upon terms and conditions contained therein;

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

"**Series A Preferred Shares**" means the Series A Convertible First Preferred Shares in the share capital of the Corporation;

"**Series B Preferred Shares**" means the Series B Convertible First Preferred Shares in the share capital of the Corporation;

"**Series C Preferred Shares**" means the Series C Convertible First Preferred Shares in the share capital of the Corporation;

"**TSXV**" means the TSX Venture Exchange;

"**U.S.**" means the United States of America;

"**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.

CONVENTIONS

Certain terms used herein are defined in the "Glossary". Unless otherwise indicated, references herein to "\$" or "**dollars**" are to Canadian dollars. All financial information with respect to the Corporation has been presented in Canadian dollars in accordance with GAAP.

ABBREVIATIONS AND CONVERSIONS

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

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.

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

<i>To Convert From</i>	<i>To</i>	<i>Multiply By</i>
Mcf	thousand cubic metres ("10 ³ m ³ ")	0.0282
thousand cubic metres	Mcf	35.494
Bbl	cubic metres ("m ³ ")	0.159
cubic metres	bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometers	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

CORPORATION STRUCTURE

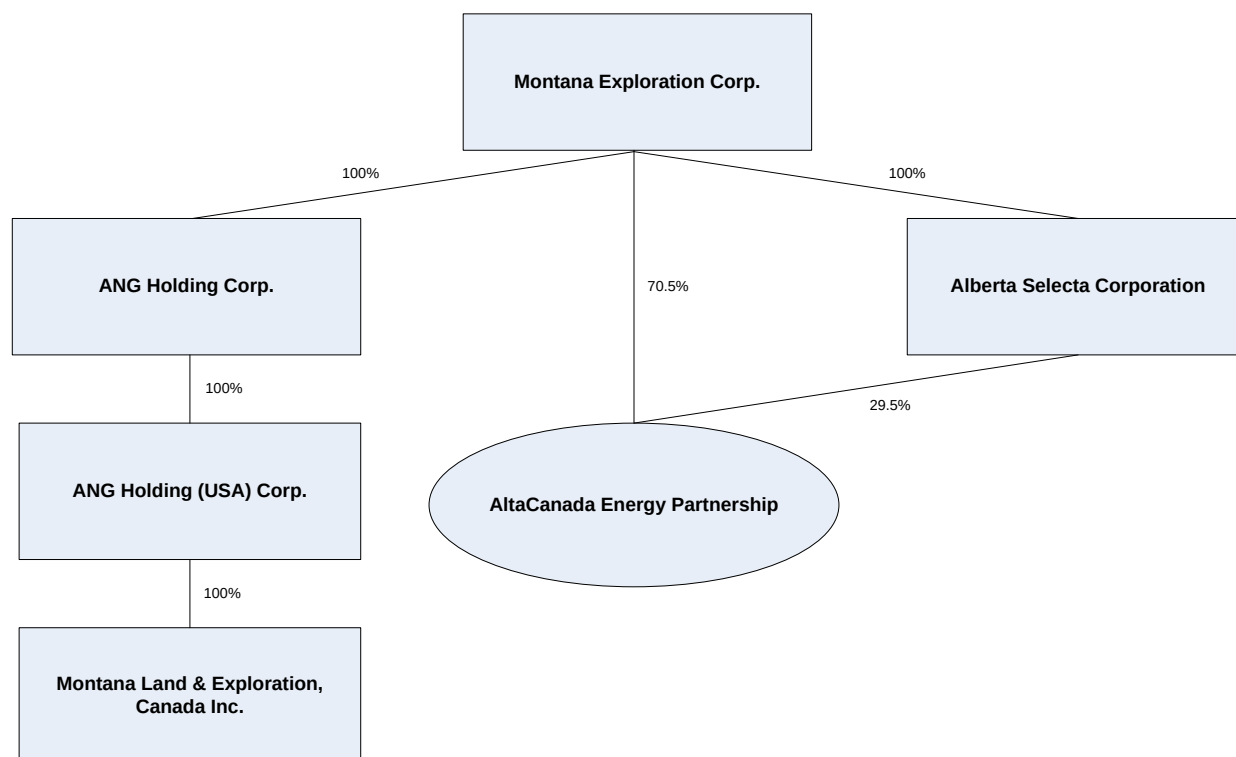
Incorporation and Organization

Montana Exploration Corp. was incorporated under the ABCA on November 12, 1997 under the legal name of AltaCanada Energy Corp. The Corporation's articles of incorporation were amended on January 16, 1998 to remove private company provisions, permit the issuance of preferred shares, 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.

On February 25, 2011 the Corporation's articles were amended to change the legal name of AltaCanada to Montana Exploration Corp. and consolidate the common shares in the capital stock of Corporation on a ten for one basis.

On February 8, 2011, February 16, 2011 and August 8, 2011 the Corporation's articles were amended to create the Series A Preferred Shares, Series B Preferred Shares and Series C Preferred Shares, respectively.

MEC 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 MEC and 29.5% by Selecta. MEC also owns 100% of the issued and outstanding securities of ANG Holding, a corporation formed pursuant to the laws of Alberta, which owns 100% of the issued and outstanding securities of ANGUS, a corporation formed pursuant to the laws of Montana, which owns 100% of the issued and outstanding securities of ML&E, a corporation formed pursuant to the laws of Montana. See "Business of the Corporation".



The head and registered offices of MEC, Selecta and ANG Holding are located at 2300, 144 – 4th Avenue S.W., Calgary, Alberta, Canada, T2P 3N4; 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.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

MEC 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, 2011, all of MEC's Canadian operations were in the Province of Alberta.

In early January 2009, 5 (2.7 net) wells were drilled on the Fort Belknap Reservation resulting in five more successful gas completions. These five wells together with 11 others previously drilled were placed on production on February 9, 2009 after completion of thirty miles of a new steel and plastic gathering system which opened up additional potential exploratory lands on which the Corporation has identified several exploration prospects.

With lower commodity prices in the later part of 2009, MEC significantly reduced its level of activity and all drilling and recompletion opportunities were deferred. Production from the Fort Belknap Reservation was suspended until June 2010 and was then produced until April, 2012 at which time it was shut-in because of low natural gas prices.

In 2011 1 (0.4) net wells were drilled in Montana and 1 (0.5 net) wells were drilled in Canada . The Montana well was suspended after not encountering commercial quantities of hydrocarbon. MEC declined to participate in the completion of the Canadian well and is currently subject to a 300% penalty. The well is producing minor quantities of gas and is not expected to pay out.

Including Montana and Canadian production, MEC's total corporate production was 1.16 mmcf/d as at March 30, 2012.

In August of 2009 MEC entered into the credit facilities with a Canadian Chartered bank which consisted of a revolving demand loan facility of \$8.25 million and a \$4.0 million non-revolving demand loan. The \$4.0 million not-revolving demand loan was required to be repaid by October 30, 2009. MEC was unable to satisfy this repayment requirement by that date, and as a result entered into a series of forbearance agreements with the bank.

On December 30, 2009, MEC entered into the Bridge Loan Facility with Brookfield and ANG Partners, Ltd., a company that is a significant shareholder of MEC and that is controlled by Mr. James Collins, a director of MEC. The bridge loan facility raised proceeds of \$3.25 million and had a maturity of July 30, 2010. From the Bridge Loan Facility, \$2.75 million was used to repay a portion of the \$4.0 million non-revolving facility and \$500,000 was used for working capital.

In June of 2010, MEC completed a rights offering pursuant to a short form prospectus to raise gross proceeds of \$6,408,843, comprised of \$3,564,193 in cash and \$2,844,650 in convertible debenture redemptions. Proceeds of the rights offering were used to repay the remaining portion of the non-revolving demand loan (\$1.25 million), other debt reduction, exploration activities on MEC's Jurassic and Bakken oil prospects and for the restart and further completion of gas wells on MEC's Fort Belknap Montana property which were shut in during the period of low gas prices to preserve value.

Recent Developments

2011 and 2012 Re-financings

In February of 2011, MEC completed a significant restructuring and refinancing which included:

- The change of the name of the corporation from AltaCanada Energy Corp. to Montana Exploration Corp.;
- The entering into of a new revolving credit facility in a maximum amount of \$5.7 million with a maturity of November 30, 2011;

- The repayment of \$2.275 million of indebtedness;
- The issuance of 212.6 million convertible preferred shares for gross proceeds of \$10.63 million;
- The extension of the Bridge Loan Facility to November 30, 2011;
- The conversion of \$330,000 principal amount of convertible debentures and accrued interest thereon to equity by the issuance of 6.9 million convertible preferred shares;
- The conversion of \$1,625,000 of the Bridge Loan Facility and accrued interest thereon to equity by the issuance of 32.5 million convertible preferred shares;
- The conversion of approximately \$0.8 million of other indebtedness to equity by the issuance of 16.0 million convertible preferred shares;
- The assignment of \$625,000 of the Bridge Loan Facility from Brookfield to ANG Partners, Ltd.;
- The consolidation of the outstanding common shares of the Corporation on a 10 for 1 basis.

Funds raised from the February 2011 private placement were used by MEC to continue exploration of several Bakken and Jurassic (Lower Shaunavon) oil opportunities previously identified by seismic, selected high return gas recompletion opportunities, and the repayment of certain financial obligations.

In March 2012, Rioco Partners Ltd. ("**Rioco**"), a limited partnership controlled by Jim Collins, a director and largest shareholder of MEC, assumed the entire balance of the credit facility from the company's principal lender, a Canadian chartered bank, through payment of approximately \$2.4 million. The Corporation has agreed in principle with Rioco to extend the term of the facility to March 1, 2014. Subject to approval of the TSXV, it is proposed that, in consideration for the extension of the credit facility and the elimination of some of the covenants, Rioco will be issued 4,000,000 warrants, each warrant entitling the holder to purchase one common share of the company at an exercise price of \$0.32 for a period of 24 months until March 1, 2014, and the credit facility will be amended to permit the conversion of the principal amount owed under the credit facility to common shares of the company at a conversion rate of \$0.32.

2012 Major Farmout and Joint Venture Agreement

In March, 2012 MEC entered into a farm-out and participation agreement with a private oil company based in Denver, USA which has agreed to make a staged commitment of approximately \$10 million to earn a fifty (50) percent interest in 110,000 net acres of MEC's lands in Montana. The commitment includes a \$6.7 million staged cash payment to MEC, a \$1.5 million 25 square mile 3-D seismic program, and \$2.0 million in drilling two initial wells to identify and pursue commercial production in the Upper and Lower Shaunavon.

DESCRIPTION OF THE BUSINESS

Operationally, the management of MEC chose a strategy in 2011 of limiting expenditures on development which resulted in lower natural gas sales in 2011, 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 MEC believes that value can be added to the Corporation by focusing on corporate and asset opportunities in Montana.

MEC holds approximately 270,000 gross acres of largely contiguous lands in the Blaine County area of Montana and in the Fort Belknap Reservation. This land position was assembled and held through drilling for shallow natural gas production and adding related infrastructure. The Fort Belknap Reservation has widespread Bakken potential and the balance of MEC's acreage has multiple potential targets for Jurassic oil production. In 2010, as the Corporation attempted to address severe financial challenges, MEC turned to high quality industry partners to facilitate an initial oil exploration program. MEC farmed out Jurassic and Bakken prospects on its lands on the basis that the industry partner would pay 80% of the costs of any new well to earn a 50% interest in that well and the same

interest in adjoining sections (nine sections in the case of a Devonian test and six sections in respect of a Jurassic test).

Together with its partners, MEC drilled a Devonian test well in October 2010 which twinned the only deeper pool test well drilled in the region, a well drilled on the reservation 53 years ago which appeared to have middle Bakken sand. A core and modern logging of the well confirmed 22 feet of Bakken sandstone with porosity of up to 18% and, most importantly, containing residual oil stain which suggested mature hydrocarbons had been generated and had migrated through this sequence.

Encouraged by the results of the first test well drilled in late 2010, MEC embarked upon a proposed additional three-well Bakken exploration program in early 2011. The first well in that program was drilled eight miles up-dip, structurally higher to the first well but did not encounter commercial quantities of hydrocarbons and the well is currently suspended pending further completion evaluation of up-hole gas zones, once natural gas prices improve.

MEC also participated in a Jurassic Shaunavon test in Blaine County in conjunction with its partner. The well at Rabbit Hills, Blaine County was structurally lower than anticipated and encountered low oil saturation. While there has been Jurassic oil production in the region for many years, future activity will be based on an active 3-D seismic program discussed above and the analysis of other exploration information.

MEC is also actively pursuing potential acquisitions and participation in oil prospects in other regions of Montana to balance the exploration risk in the Corporation and provide substantial prospects for future growth.

2011 was a year of transition commencing with a recapitalization, share consolidation and name change for the Corporation. During the year the company's efforts were focused upon developing oil opportunities, both on its substantial Blaine County acreage position and on other areas of Montana. During 2011 MEC repaid a substantial proportion of its outstanding bank debt and undertook drilling of a Bakken oil target on its Fort Belknap property exposing a modest amount of capital (approximately 12% of total well cost) in conjunction with partners. While that single well was not a commercial success, it showed the presence of oil within the Bakken system and the potential for discoveries structurally higher to the North West on our acreage position.

MEC's primary focus in the next six months will be on the Upper and Lower Shaunavon prospects on approximately 150,000 acres of our total 270,000 net Montana acreage position which is the extension of the proven Shaunavon trend from north of the Canada/US border where hundreds of wells have been drilled over the past several years by Cenovus, Crescent Point, Talisman, Husky and others. There is offsetting production in Montana from the Lower Shaunavon at Bowes Field (operated by Citation – 13.5 million barrels to date) and at the Rabbit Hills Field (operated by Paramount – 3.5 million barrels to date). MEC's goal has been to analyze the potential of its own acreage position based upon 600 miles of 2-D data and all existing Shaunavon wells, to secure a partner that would validate the value of its acreage position and participate actively in the play.

Following six months of due diligence, MEC signed a joint venture on March 30, 2012 with a Denver based partner with a highly qualified technical and management staff supported by private equity investors. The joint venture partner has committed approximately \$10 million comprised of a staged cash payment of \$6.7 million, a 25 square mile 3-D seismic program (we have agreed on a 50 square mile total 3D program and MTZ will pay 50% of the incremental 25 square miles) and a partial carry of MEC on 2 new wells. Upon completion, MEC's partner will earn a 50% interest in approximately 110,000 net acres representing a substantial proportion of MEC's acreage on the Shaunavon trend. The joint venture commitment is equivalent to approximately \$170 per acre or approximately \$0.60/share on a fully diluted basis.

To support the re-initiation of activities on the Company's acreage MEC has identified five initial Shaunavon play types: the first two are Upper and Lower Shaunavon targets based upon mound features and Paleozoic highs offsetting the existing Rabbit Hills field (25 features have been identified on 2D seismic alone); the third play type consists of drill ready development wells in the Lower Shaunavon offsetting Bowes Field (4 initial locations); the fourth play is a feature similar to Bowes field identified on 2D seismic (the first target of our 3D seismic program) and the fifth is a channel play on the eastern part of the Shaunavon trend.

The company expects to commence a 3-D program on the Shaunavon oil targets in May. The Shaunavon exists on MEC's acreage at depths of between 4,000 and 4,500 feet. A "double" rig is available to commence drilling in June. Vertical well costs are expected to be about \$600,000 and horizontal well costs are expected to be about \$1.9 million. The current plan is to execute a first year program of approximately 13 wells and MEC is moving ahead with a capital raising program to support this seismic and drilling program initiative.

MEC's existing natural gas properties, comprising almost 100 wells, have been excluded from the joint venture. The price of natural gas continues to retreat and has seriously impacted both the value and the amount of natural gas the Company has booked as reserves. MEC's Montana reserves are at shallow depths and do not contain natural gas liquids. Three years ago, in December 2008, MEC reported 17 bcf of gas reserves which its independent evaluation valued at \$32 million (P+P 10% discount). At current pricing, the same evaluation presents 2P reserves of only 3 bcf of economic gas valued at \$2 million. The majority of the gas is still there but is not economic at today's pricing. With increases in gas prices this value will return. At this time MEC is determined to broaden its activities to assess and commercialize the oil potential on its large land position.

MEC no longer has any bank debt. The refinancing, renaming and consolidation completed in February 2011 left \$3.4 million of debt but as announced in February 2012 most of this last block of bank debt was assumed by MEC's principal shareholder, who has removed onerous covenants and agreed to hold that debt as a convertible instrument until February, 2014.

If MEC is able to manage its assets in the manner that is planned, 2012 will see significant investment in its large Montana land block focused on a series of oil prospects. The company is eager to invest new capital in the ground to unlock the oil value of the large land holding and to deliver value to the company stakeholders.

Montana Drilling

Prior to 2010, the Corporation's principal objective was the Eagle sandstones, which are the stratigraphic equivalent of the Milk River sands of southeast Alberta and southwest Saskatchewan. In Canada, 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 drilling mud and fracture techniques. The Corporation has utilized this Canadian technology in Blaine County.

Blaine County is both a conventional sand play and a tight sand reservoir. The west side of MEC's block has great quality reservoirs with over 100 feet of sand yielding 500 mcf/d, un-fractured. On the east side, progressively tighter sands are present, which require significant "fracs" to produce 30 to 100 mcf/d. Between these areas MEC has wells that can initially produce between 200-300 Mcf/d. Additionally, Blaine County has an important structural component providing MEC with "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 MEC'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, MEC still averages U.S.\$125,000 per cased well.

Prior to 2010, most of the Corporation's activities were directed to the shallow Eagle formation. MEC's extensive seismic shooting, although initially focused on this shallow gas drilling, followed up by a successful 3-D seismic data program, has identified drillable oil targets in the Jurassic Sawtooth (Shaunavon formation). An extensive 3-D seismic program will be carried out in 2012 as well as the drilling of at least two Shaunavon test wells.

The Jurassic oil targets are at about 4,200 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 range.

Seasonal Factors

The development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

Human Resources

As at December 31, 2011, MEC had 8 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.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The Statement of Reserves Data and Other Oil and Gas Information is dated March 22, 2012 and is effective December 31, 2011. The preparation date of the information regarding reserves in this AIF and of the GLJ Report was March 16, 2012.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached to this Annual Information Form as Schedules A and B, respectively.

The future net revenue numbers herein, 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 and 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 "Definitions, Notes and Other Cautionary Statements" in this AIF.

The information relating to the natural gas, oil and NGL reserves of the Corporation contains forward looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "*Forward-Looking Statements*" and "*Risk Factors*".

All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the estimates of future net revenues presented in the following tables represent the fair market value of the Corporation's reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GJL Report. The recovery and reserves estimates of the Corporation's properties described herein are estimates only. The actual reserves on the Corporation's properties may be greater or less than those calculated. For more information on the risks involved, see "*Forward-Looking Statements*" and "*Risk Factors*".

All of the Corporation's reserves and production are located in the province of Alberta, Canada and the state of Montana, United States of America.

Summary of Oil and Gas Reserves

The following tables detail the aggregate gross and net reserves of the Corporation, both in the aggregate and by country, as at December 31, 2011, using forecast prices and costs. There have been significant reductions in both proven and probable reserves due to a significant reduction in natural gas prices.

SUMMARY OF OIL AND GAS RESERVES – TOTAL CANADA AND U.S. FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2011

Reserves category	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net	Company Gross	Company Net
	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	Mboe	Mboe
Proved										
Developed Producing	2	2	2	2	867	739	0	0	148	127
Developed Non-producing	0	0	0	0	400	323	0	0	67	54
Undeveloped	0	0	0	0	587	457	0	0	98	76
Total Proved	2	2	2	2	1,854	1,518	0	0	313	257
Total Probable	1	1	1	1	1,456	1,195	0	0	244	200
Total Proved Plus Probable	2	2	3	3	3,310	2,713	0	0	557	457

SUMMARY OF OIL AND GAS RESERVES BY COUNTRY FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2011

Entity Description	Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross Mbbl	Net Mbbl	Gross Mbbl	Net Mbbl	Gross MMcf	Net MMcf	Gross Mbbl	Net Mbbl	Gross Mbbl	Net Mbbl
Proved Developed Producing										
Total Canada After Tax	2	2	2	2	420	375	0	0	74	66
Total U.S. After Tax	0	0	0	0	447	364	0	0	75	61
Total: Proved Developed Producing	2	2	2	2	867	739	0	0	148	127
Proved Developed Nonproducing										
Total Canada After Tax	0	0	0	0	182	152	0	0	31	25
Total U.S. After Tax	0	0	0	0	218	171	0	0	36	28
Total: Proved Developed Nonproducing	0	0	0	0	400	323	0	0	67	54
Proved Undeveloped										
Total Canada After Tax	0	0	0	0	50	47	0	0	8	8
Total U.S. After Tax	0	0	0	0	537	409	0	0	89	68
Total: Proved Undeveloped	0	0	0	0	587	457	0	0	98	76
Total Proved										
Total Canada After Tax	2	2	2	2	652	574	0	0	113	99
Total U.S. After Tax	0	0	0	0	1,202	944	0	0	200	157
Total: Total Proved	2	2	2	2	1,854	1,518	0	0	313	257

**SUMMARY OF OIL AND GAS RESERVES BY COUNTRY
FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2011**

Entity Description	Reserves									
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross Mbbl	Net Mbbl	Gross Mbbl	Net Mbbl	Gross MMcf	Net MMcf	Gross Mbbl	Net Mbbl	Gross Mbbl	Net Mbbl
<i>Total Probable</i>										
Total Canada After Tax	1	1	1	1	292	263	0	0	50	45
Total U.S. After Tax	0	0	0	0	1,164	933	0	0	194	155
Total: Total Probable	1	1	1	1	1,456	1,195	0	0	244	200
<i>Total Proved Plus Probable</i>										
Total Canada After Tax	2	2	3	3	944	836	0	0	163	144
Total U.S. After Tax	0	0	0	0	2,365	1,877	0	0	394	313
Total: Total Proved Plus Probable	2	2	3	3	3,310	2,713	0	0	557	457

Summary of Net Present Values of Future Net Revenue

The following tables detail the aggregate net present values of future net revenue attributable to MEC's reserves estimated using forecast prices and costs, calculated without discount and using discount rates of 0%, 5%, 10%, 15% and 20%, both in the aggregate and by country, and both before income taxes and after, as well as on a unit value basis using a discount rate of 10% calculated before taxes.

Net Present Values of Future Net Revenue - Total

**NET PRESENT VALUES OF FUTURE NET REVENUE
FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2011**

Reserves Category	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
	0%	5%	10%	15%	20%	\$/boe	\$/Mcfe
	M\$	M\$	M\$	M\$	M\$		
Proved							
Developed Producing	979	606	381	234	131	3.01	0.50
Developed Non-producing	132	100	75	56	40	1.40	0.23
Undeveloped	496	385	303	242	196	3.98	0.66
Total Proved	1,607	1,091	759	532	368	2.96	0.49
Total Probable	2,358	1,672	1,255	978	784	6.26	1.04
Total Proved Plus Probable	3,965	2,763	2,014	1,510	1,152	4.41	0.73

Reserves Category	Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)						
	0%	5%	10%	15%	20%		
	M\$	M\$	M\$	M\$	M\$		
Proved							
Developed Producing	979	606	381	234	131		
Developed Non-producing	132	100	75	56	40		
Undeveloped	496	385	303	242	196		
Total Proved	1,607	1,091	759	532	368		
Total Probable	2,358	1,672	1,255	978	784		
Total Proved Plus Probable	3,965	2,763	2,014	1,510	1,152		

Net Present Values of Future Net Revenue - Canada

**NET PRESENT VALUES OF FUTURE NET REVENUE
FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2011**

Reserves Category	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
	0% M\$	5% M\$	10% M\$	15% M\$	20% M\$	\$/boe	\$/Mcfe
Proved							
Developed Producing	1,282	918	699	556	456	10.59	1.77
Developed Non-producing	85	58	37	22	10	1.48	0.25
Undeveloped	85	63	48	36	28	6.00	1.00
Total Proved	1,452	1,039	784	614	493	7.92	1.32
Total Probable	1,028	719	554	451	381	12.31	2.05
Total Proved Plus Probable	2,480	1,758	1,338	1,065	874	9.29	1.55

Reserves Category	Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)						
	0% M\$	5% M\$	10% M\$	15% M\$	20% M\$		
Proved							
Developed Producing	1,282	918	699	556	456		
Developed Non-producing	85	58	37	22	10		
Undeveloped	85	63	48	36	28		
Total Proved	1,452	1,039	784	614	493		
Total Probable	1,028	719	554	451	381		
Total Proved Plus Probable	2,480	1,758	1,338	1,065	874		

Net Present Values of Future Net Revenue - United States

**NET PRESENT VALUES OF FUTURE NET REVENUE
FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2011**

Reserves Category	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
	0% M\$	5% M\$	10% M\$	15% M\$	20% M\$	\$/boe	\$/Mcfe
Proved							
Developed Producing	-303	-312	-318	-322	-325	-5.21	-0.87
Developed Non-producing	47	43	38	34	30	1.36	0.23
Undeveloped	411	321	255	206	169	3.75	0.63
Total Proved	155	52	-25	-82	-126	-0.16	-0.03
Total Probable	1,331	953	700	526	404	4.52	0.75
Total Proved Plus Probable	1,485	1,005	676	444	278	2.16	0.36

Reserves Category	Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)						
	0% M\$	5% M\$	10% M\$	15% M\$	20% M\$		
Proved							
Developed Producing	-303	-312	-318	-322	-325		
Developed Non-producing	47	43	38	34	30		
Undeveloped	411	321	255	206	169		
Total Proved	155	52	-25	-82	-126		
Total Probable	1,331	953	700	526	404		
Total Proved Plus Probable	1,485	1,005	676	444	278		

Additional Information Concerning Future Net Revenue – (Undiscounted)

The following table details the future net revenue attributable to (i) proved reserves and (ii) proved plus probable reserves, estimated using forecast prices and costs, by country and in the aggregate, for each of the elements of future net revenue appearing below, without discount.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) BY COUNTRY FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2011								
Reserves Category	Revenue M\$	Royalties M\$	Operating Costs M\$	Capital Development Costs M\$	Abandonment Costs M\$	Future Net Revenue Before Income Taxes M\$	Income Tax M\$	Future Net Revenue After Income Taxes M\$
<i>Total Proved</i>								
Total Canada	4,592	338	2,235	277	289	1,452	0	1,452
Total U.S.	5,761	1,623	3,227	296	460	155	0	155
Total: Total Proved	10,353	1,961	5,463	573	749	1,607	0	1,607
<i>Total Proved Plus Probable</i>								
Total Canada	6,856	499	3,186	368	324	2,480	0	2,480
Total U.S.	12,388	3,393	6,058	915	537	1,485	0	1,485
Total: Total Proved Plus Probable	19,244	3,891	9,243	1,283	861	3,965	0	3,965

Net Present Value of Future Net Revenue by Production Group

The table below details the net present value of future net revenue, before taxes, estimated using forecast prices and costs and calculated using a discount rate of 10% by production group and on a unit value basis for each production group.

NET PRESENT VALUE OF FUTURE NET REVENUE BY PRODUCTION GROUP IN AGGREGATE AND ON A UNIT VOLUME BASIS FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2011 BEFORE INCOME TAXES (DISCOUNTED AT 10% PER YEAR)			
	Aggregate	Unit Volumes⁽³⁾	
	M\$	\$/boe	\$/Mcfe
<i>Proved Producing</i>			
Total Canada			
Light & Medium Oil ⁽¹⁾	91	56.67	9.45
Heavy Oil ⁽¹⁾	78	40.67	6.78
Natural Gas ⁽²⁾	530	8.49	1.41
Total: Total Canada	699	10.59	1.77
Total U.S.			
Natural Gas ⁽²⁾	-318	0.00	0.00
Total: Total U.S.	-318	0.00	0.00
Total: Proved Producing	381	3.01	0.50
<i>Total Proved</i>			
Total Canada			
Light & Medium Oil ⁽¹⁾	91	56.67	9.45
Heavy Oil ⁽¹⁾	78	40.67	6.78
Natural Gas ⁽²⁾	615	6.42	1.07
Total: Total Canada	784	7.90	1.32

**NET PRESENT VALUE OF
FUTURE NET REVENUE BY PRODUCTION GROUP
IN AGGREGATE AND ON A UNIT VOLUME BASIS
FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2011
BEFORE INCOME TAXES (DISCOUNTED AT 10% PER YEAR)**

	Aggregate	Unit Volumes ⁽³⁾	
	M\$	\$/boe	\$/Mcf
Total U.S.			
Natural Gas ⁽²⁾	-25	0.00	0.00
Total: Total U.S.	-25	0.00	0.00
Total: Total Proved	759	2.96	0.49
<i>Total Proved Plus Probable</i>			
Total Canada			
Light & Medium Oil ⁽¹⁾	108	49.36	8.23
Heavy Oil ⁽¹⁾	98	38.61	6.44
Natural Gas ⁽²⁾	1,133	8.12	1.35
Total: Total Canada	1,338	9.27	1.55
Total U.S.			
Natural Gas ⁽²⁾	676	2.16	0.36
Total: Total U.S.	676	2.16	0.36
Total: Total Proved Plus Probable	2,014	4.41	0.73

Notes

- (1) Including solution gas and other by-products
(2) Including by-products but excluding solution gas
(3) Unit values are based on Company Net Reserves.

Pricing Assumptions

The following tables detail the benchmark reference prices for the regions in which the Corporation operated as at December 31, 2011 reflected in the reserves data disclosed above. 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.

FORECAST PRICES USED IN RESERVE DATA

**GLJ PETROLEUM CONSULTANTS LTD.
CRUDE OIL AND NATURAL GAS LIQUIDS
PRICE FORECAST
EFFECTIVE JANUARY 1, 2012**

Year	Inflation %	Exchange Rate \$US/\$Cdn	Nymex Wti			Lloyd			Light Crude Oil (35 API, Cromer)	Medium Crude Oil (29 API, Cromer)	Alberta Natural Gas Liquids (Then Current Dollars)	Edmonton Propane \$Cdn/bbl	Edmonton Butane \$Cdn/bbl	Edmonton Pentanes Plus \$Cdn/bbl
			Near Month	Light Sweet	Bow River	Blend	Heavy	Light						
			Futures	Crude Oil	Crude Oil	Crude Oil	Crude Oil	Crude Oil						
			Contract	40 API,	Stream	Stream	Proxy (12	(35 API,						
			Crude Oil	0.3%S at	Quality at	Quality at	API) at	1.2%S) at						
Bank of Canada Average Noon	at Cushing Oklahoma	Edmonton	Hardisty	Hardisty	Hardisty	Cromer	Cromer	Cromer	Cromer	Cromer	Cromer	Cromer	Cromer	Cromer
			\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl	\$Cdn/bbl

FORECAST PRICES USED IN RESERVE DATA

**GLJ PETROLEUM CONSULTANTS LTD.
CRUDE OIL AND NATURAL GAS LIQUIDS
PRICE FORECAST
EFFECTIVE JANUARY 1, 2012**

Year	Inflation %	Exchange Rate \$US/\$Cdn	Nymex Wti Near Month Futures Contract Crude Oil at Cushing Oklahoma \$Cdn/bbl	Light Sweet Crude Oil 40 API, 0.3%S at Edmonton \$Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty \$Cdn/bbl	Lloyd Blend Crude Oil Stream Quality at Hardisty \$Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty \$Cdn/bbl	Light Crude Oil (35 API, 1.2%S) at Cromer \$Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer \$Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars)			Edmonton Pentanes Plus \$Cdn/bbl
										Edmonton Propane \$Cdn/bbl	Edmonton Butane \$Cdn/bbl		
2012	2.0	0.980	97.00	97.96	83.27	81.31	72.37	93.06	90.12	58.78	76.41		107.76
2013	2.0	0.980	100.00	101.02	84.35	82.33	73.60	94.96	92.94	60.61	78.80		108.09
2014	2.0	0.980	100.00	101.02	84.35	82.33	74.51	93.95	91.93	60.61	78.80		105.06
2015	2.0	0.980	100.00	101.02	84.35	82.33	74.51	93.95	91.93	60.61	78.80		105.06
2016	2.0	0.980	100.00	101.02	84.35	82.33	74.51	93.95	91.93	60.61	78.80		105.06
2017	2.0	0.980	100.00	101.02	84.35	82.33	74.51	93.95	91.93	60.61	78.80		105.06
2018	2.0	0.980	101.35	102.40	85.50	83.45	75.54	95.23	93.18	61.44	79.87		106.49
2019	2.0	0.980	103.38	104.47	87.23	85.14	77.09	97.16	95.07	62.68	81.49		108.65
2020	2.0	0.980	105.45	106.58	89.00	86.86	78.67	99.12	96.99	63.95	83.13		110.84
2021	2	0.980	107.56	108.73	90.79	88.62	80.28	101.12	98.95	65.24	84.81		113.08
2022+	2.0	0.980	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr		+2.0%/yr

FORECAST PRICES USED IN PREPARING RESERVES DATA

**GLJ PETROLEUM CONSULTANTS LTD.
NATURAL GAS AND SULPHUR
PRICE FORECAST
EFFECTIVE JANUARY 1, 2012**

Year	Alberta Plant Gate						
	Henry Hub Nymex Near Month Contract \$US/mmbtu	Midwest Price @ Chicago \$US/mmbtu	AECO/NIT Spot \$Cdn/mmbtu	Spot \$/mmbtu	ARP \$/mmbtu	Aggregator \$/mmbtu	Alliance \$/mmbtu
2000	4.32	3.96	5.08	4.93	4.50	4.44	N/A
2001	4.03	4.45	6.23	6.07	5.41	4.97	5.29
2002	3.36	3.25	4.04	3.88	3.88	3.64	3.66
2003	5.47	5.46	6.66	6.49	6.13	5.87	6.15
2004	6.18	6.13	6.88	6.70	6.31	6.16	6.39
2005	9.00	8.24	8.58	8.42	8.30	8.27	8.29
2006	6.99	6.93	7.16	6.96	6.57	6.36	6.34
2007	7.12	6.83	6.65	6.43	6.20	6.13	5.86
2008	8.90	8.91	8.16	7.92	7.88	7.85	7.84
2009	4.16	4.05	4.19	3.98	3.85	3.69	3.23
2010	4.40	4.53	4.17	3.93	3.77	3.63	3.31
2011	4.03	4.26	3.68	3.47	3.57	3.40	2.89
2012	3.80	3.90	3.49	3.29	3.23	3.15	2.65
2013	4.50	4.60	4.13	3.93	3.85	3.76	3.33
2014	5.00	5.10	4.59	4.39	4.30	4.20	3.82
2015	5.50	5.60	5.05	4.84	4.74	4.64	4.31
2016	6.00	6.10	5.51	5.30	5.19	5.08	4.80
2017	6.50	6.60	5.97	5.75	5.64	5.51	5.29
2018	6.76	6.86	6.21	5.99	5.87	5.74	5.55

FORECAST PRICES USED IN PREPARING RESERVES DATA

**GLJ PETROLEUM CONSULTANTS LTD.
NATURAL GAS AND SULPHUR
PRICE FORECAST
EFFECTIVE JANUARY 1, 2012**

Alberta Plant Gate							
Year	Henry Hub Nymex Near Month Contract \$US/mmbtu	Midwest Price @ Chicago \$US/mmbtu	AECO/NIT Spot \$Cdn/mmbtu	Spot \$/mmbtu	ARP \$/mmbtu	Aggregator \$/mmbtu	Alliance \$/mmbtu
2019	6.89	6.99	6.33	6.11	5.98	5.85	5.67
2020	7.03	7.13	6.46	6.23	6.11	5.98	5.81
2021	7.17	7.27	6.58	6.36	6.23	6.10	5.95
2022+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.

The plant gate price represents the price before raw gas gathering and processing charges are deducted.

AECO-C Spot refers to the one month price averaged for the year.

In Canada, the Corporation's weighted average prices received in 2011 were \$60.58/bbl for oil, and \$3.67/mcf for natural gas. The Corporation's light and medium oil production is negligible.

In the U.S., the Corporation's weighted average price received in 2011 was \$3.53/mcf for natural gas.

Reconciliations of Changes in Reserves and Future Net Revenue

The following tables provide a reconciliation of MEC's gross reserves of oil and natural gas for the year ended December 31, 2011 presented using forecast prices and costs, in total for Canada and the U.S., and for each of Canada and the U.S.

**RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE**

**FORECAST PRICES AND COSTS – TOTAL CANADA AND U.S.
AS AT DECEMBER 31, 2011**

FACTORS	Total Oil			Light and Medium Oil			Heavy Oil		Natural Gas Liquids			
	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +
	(Mbbl)	(Mbbl)	Probable (Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
December 31, 2010	5	3	8	0	0	0	5	3	8	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Infill	0	0	0	0	0	0	0	0	0	0	0	0
Drilling												
Improved	0	0	0	0	0	0	0	0	0	0	0	0
Recovery												
Technical	(2)	(2)	(4)	0	0	0	(2)	(2)	(4)	(0)	(1)	(1)
Revisions												
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic	0	0	0	0	0	0	0	0	0	0	0	0
Factors												
Production	(1)	0	(1)	0	0	0	(1)	0	(1)	(0)	0	(0)
December 31, 2011	5	3	8	0	0	0	5	3	8	0	0	0

FACTORS	Total Gas			Conventional Natural Gas			Coal Bed Methane		BOE			
	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +
	(MMcf)	(MMcf)	Probable (MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(Mboe)	(Mboe)	(Mboe)
December 31, 2010	3,585	2,843	6,428	3,585	2,843	6,428	0	0	0	603	476	1,079
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Infill	0	0	0	0	0	0	0	0	0	0	0	0
Drilling												
Improved	0	0	0	0	0	0	0	0	0	0	0	0
Recovery												
Technical	(102)	(300)	(402)	(102)	(300)	(402)	0	0	0	(19)	(50)	(69)
Revisions												
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic	(1,204)	(1,093)	(2,297)	(1,204)	(1,093)	(2,297)	0	0	0	(201)	(183)	(384)
Factors												
Production	(439)	0	(439)	(439)	0	(439)	0	0	0	(74)	0	(74)
December 31, 2011	1,840	1,451	3,290	1,840	1,451	3,290	0	0	0	309	243	552

**RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE**

**FORECAST PRICES AND COSTS – TOTAL CANADA
AS AT DECEMBER 31, 2011**

FACTORS	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
December 31, 2010	5	3	8	0	0	0	5	3	8	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	(2)	(2)	(4)	(0)	0	(0)	(2)	(2)	(4)	(0)	(1)	(1)
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0		0	0	0	0	0	0	0	0	(1)	(1)
Production	(1)	0	(1)	0	0	0	(1)	0	(1)	(0)	0	(0)
December 31, 2011	2	1	3	0	0	0	2	1	3	0	0	0

FACTORS	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(Mboe)	(Mboe)	(Mboe)
December 31, 2010	965	428	1,393	965	428	1,393	0	0	0	166	74	240
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	135	(50)	85	135	(50)	85	0	0	0	21	(10)	11
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	(47)	(47)	0	(47)	(47)	0	0	0	0	(8)	(8)
Economic Factors	(322)	(91)	(413)	(322)	(91)	(413)	0	0	0	(54)	(16)	(70)
Production	(140)	0	(140)	(140)	0	(140)	0	0	0	(24)	0	(24)
December 31, 2011	638	287	925	638	287	925	0	0	0	109	48	157

**RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE**

**FORECAST PRICES AND COSTS – TOTAL U.S.
AS AT DECEMBER 31, 2011**

FACTORS	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
	Proved (Mbbbl)	Probable (Mbbbl)	Proved + Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved + Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved + Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved + Probable (Mbbbl)
December 31, 2010	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0	0	0	0	1	1
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	(1)	(1)
Production	0	0	0	0	0	0	0	0	0	0	0	0
December 31, 2011	0	0	0	0	0	0	0	0	0	0	0	0

FACTORS	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
December 31, 2010	2,620	2,415	5,035	2,620	2,415	5,035	0	0	0	437	402	839
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	(237)	(250)	(487)	(237)	(250)	(487)	0	0	0	(40)	(40)	(80)
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	(882)	(1,002)	(1,884)	(882)	(1,002)	(1,884)	0	0	0	(147)	(168)	(315)
Production	(299)	0	(299)	(299)	0	(299)	0	0	0	(50)	0	(50)
December 31, 2011	1,202	1,164	2,365	1,202	1,164	2,365	0	0	0	200	194	394

Additional Information Relating to Reserves Data

Undeveloped Reserves

In general, proved undeveloped reserves and probable undeveloped reserves are assigned on the basis that there is a reasonable likelihood that the reserves may be developed within the next one or two years. There are no probable undeveloped reserves assigned.

As at December 31, 2011, the net capital, as estimated in the GLJ report, to develop proved undeveloped reserves is \$41,000 in 2012 and \$200,000 in 2013. The estimated net capital expenditure for probable undeveloped reserves is \$nil for 2012 and \$nil for 2013. The 2012 estimated cash flow does not provide the financial ability to conduct some of this development but the Corporation has financing plans underway to provide the balance of capital to develop proved undeveloped gas reserves, subject to improved gas prices.

For the year ending December 31, 2011 there were neither proved undeveloped nor probable undeveloped reserves attributed. The following table outlines gross reserves first attributed by year.

Company Gross Reserves First Attributed By Year

Proved Undeveloped Reserves

	Light & Medium Oil		Heavy Oil (Mbbbl)		Natural Gas (MMcf)		Natural Gas Liquids		Oil Equivalent (Mbbbl)	
	*First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	-	-	-	-	655	1,700	-	-	109	283
2009	-	-	-	-	-	1,696	-	-	-	283
2010	-	-	-	-	-	1,696	-	-	-	283
2011	-	-	-	-	-	587	-	-	-	98

Probable Undeveloped Reserves

	Light & Medium Oil		Heavy Oil (Mbbbl)		Natural Gas (MMcf)		Natural Gas Liquids		Oil Equivalent (Mbbbl)	
	*First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
Prior	-	-	-	-	400	3,000	-	-	67	500
2009	-	-	-	-	627	3,627	-	-	105	605
2010	-	-	-	-	-	3,627	-	-	-	605
2011	-	-	-	-	-	433	-	-	-	72

* refers to reserves first attributed at year-end of the corresponding fiscal year.

Significant Factors or Uncertainties

Estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as availability of capital to fund required infrastructure, commodity prices, production performance of re-completed wells and well re-completion success rates, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Corporation's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Other than as discussed above and the various risks and uncertainties that participants in the oil and gas industry are exposed to generally, MEC is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein. For details of important economic factors or significant uncertainties that may affect the components of the reserves data set forth herein, see The Corporation's Management's Discussion and Analysis 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 reserves in Canada.

**Future Development Costs
Canadian Reserves
(\$thousands)**

	Proved Reserves (Forecast prices and costs)	Proved plus Probable Reserves (Forecast prices and costs)
2012	128	128
2013	1	1
2014	0	0
2015	93	93
2016	0	0
Remainder	55	57
Total Undiscounted	277	279
Total Discounted at 10%	216	234

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 Corporations reserves in the U.S.

**Future Development Costs
US Reserves
(\$thousands)**

	Proved Reserves (Forecast prices and costs)	Proved plus Probable Reserves (Forecast prices and costs)
2012	44	44
2013	200	494
2014	0	133
2015	53	244
2016	0	244
Remainder	-	-
Total Undiscounted	296	915
Total Discounted at 10%	253	750

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 MEC having significant interests and assets in the following areas of Alberta and Montana. Reserve amounts are gross reserves based on forecast 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, 2011, except where otherwise indicated.

Viking Kinsella, Alberta

MEC controls interests averaging 29 percent in 26,807 gross (7,873 net) acres at Viking Kinsella, Alberta 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 completed at no cost to the Corporation.

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

In late 2011, MEC participated as to a 45% working interest in a horizontal Basal Colorado gas well but because of poor log results, high frac costs and declining gas prices did not participate in the completion of the well and is subject to a 300% penalty.

MEC evaluated 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, difficulties were encountered in putting the well into production as a result of 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. To June, 2011 this well only produced 5200 barrels of oil and was shut-in. In late 2011 MEC accepted an offer to sell this well and various minor interests offsetting it for \$225,000. This sale was closed in March, 2012.

Killam, Alberta

MEC owns varying interests in 28,963 gross (2,439 net) acres at Killam, Alberta 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 MEC believes that there is potential to increase its production with infill locations combined with well stimulation programs.

In 2008, MEC assumed an additional 66.35% working interest in a suspended Viking gas well. Testing and potential tie-in of this well has been deferred pending higher gas prices.

Cardiff, Alberta

MEC owns an average of a 42 percent interest in 6,080 acres (2,537 net) at Cardiff, Alberta. 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. MEC's interest is an overriding royalty of 5.8 percent. A second well, in which MEC 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 2011 and none is proposed for 2012.

Blaine County, Montana

MEC 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 Oil & Gas Company LLC and Omimex Canada, Limited and to the west by the Bowes Field operated by Citation Oil and Gas Corp, 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.

MEC 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 MEC's delivery system and stepping out to explore the balance of its huge block were accomplished from 2005 to 2009.

To date ML&E'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 un-fractured 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 (i.e., 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 361,864 gross (273,425 net) acres, including 232,705 net acres of undeveloped lands.

ML&E 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 the AECO index.

All of ML&E's gas is moved through three separate gathering 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 a system have restricted flow due to pipeline or compressor restrictions. The capacity provided by this interconnection and supplemented by new compression at Harlem installed in the first quarter of 2007, will support the flow requirements of future infill drilling programs.

Only a portion of the potential pools were included as proven undeveloped or probable reserves. Subject to improved gas prices 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 2009, an additional five (2.7 net) wells were drilled resulting in five (2.7 net) gas wells. There was no Eagle gas drilling activity in 2010.

In addition, several attractive Jurassic oil opportunities have been identified by seismic on MEC's lands. Such zones, which are productive in nearby fields, are planned for exploration in 2012. Five initial Shaunavon play types have been identified: the first two are Upper and Lower Shaunavon targets based upon mound features and Paleozoic highs offsetting the existing Rabbit Hills field (25 features have been identified on 2D seismic alone); the third play type consists of drill ready development wells in the Lower Shaunavon offsetting Bowes Field (4 initial locations); the fourth play is a feature similar to Bowes field identified on 2D seismic (the first target of our 3D seismic program) and the fifth is a channel play on the eastern part of the Shaunavon trend.

In 2010 MEC participated in a Jurassic Shaunavon test. The well located at Rabbit Hills, Blaine County was structurally lower than was anticipated and encounters low oil saturation. Future activity will be based on an active 3-D seismic data program, the results of an aerial based survey, and the analysis of other exploration information.

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 Fort Belknap Indian 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. Because of declining well rates and uneconomic gas prices, these wells were shut in early 2012 and will remain suspended until gas prices improve.

The Fort Belknap Reservation has widespread Bakken and other deep zone potential. Together with its partners, MEC drilled a Devonian test well in October 2010 which twinned the only deeper pool test, drilled in the region 53

years ago, which appeared to have middle Bakken sand. Core and modern logs in the new well confirmed 22 feet of Bakken sandstone with up to 18% of porosity containing residual oil stain, which suggests that mature hydrocarbons had been generated and had migrated through this sequence. Follow up drilling was conducted in early 2011 eight miles up-dip, structurally higher to the first well, but was not successful. Gas exploration on this large reservation will be deferred until natural gas prices improve.

A major 3-D seismic program is planned for 2012 to identify primarily Shaunavon and other deeper exploration targets on this large land base followed up by the drilling of at least two Shaunavon oil tests.

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, 2011, which are producing or capable of producing.

<u>Alberta Wells</u>											
Light & Medium Oil		Heavy Oil		Natural Gas		Suspended		Service		Total	
Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
5	0	5	0.9	87	14.1	58	11.1	2	-	157	26.1

<u>Montana Wells</u>											
Light & Medium Oil		Heavy Oil		Natural Gas		Suspended		Service		Total	
Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
-	-	-	-	40	37	81	73	-	-	121	110

Existing production delivers natural 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 2012 in Blaine County. See "Business of the Corporation – 2012 Activities".

Properties with No Attributed Reserves

The following table sets out the undeveloped land holdings of the Corporation as at December 31, 2011.

	Undeveloped	
	Gross	Net
Alberta	8,660	647
Montana	321,001	233,810

Of this acreage, approximately 30,000 net acres in Montana are due to expire during 2012. Extensions for additional terms can be signed for all expiring lands.

Development of these land holdings are dependent upon the success of the oil exploration program scheduled for the next few years and/or an improvement in natural gas pricing to justify additional drilling.

Forward Contracts

The Corporation uses derivative financial instruments to manage its commodity price exposure. Financial instruments realized in the year ended December 31, 2011 are:

Natural Gas Hedges

Volume (GJ/day)	\$/GJ	Term	Gain (Loss) Realized Year Ended December 31, 2011
1,000	\$5.42	April 2010 to March 2011	220,356
Total			\$220,356

At December 31, 2011 the Corporation did not have any hedges outstanding.

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, 2011, management expected to incur such costs on 123 net wells. The total of such costs, net of estimated salvage value, was \$861,000 (undiscounted) and \$591,000 (discounted at 10%). Future net revenue amounts set forth herein only include abandonment liabilities for wells assigned reserves. Within the next three financial years, it is expected such costs will total approximately \$514,000.

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 neither be taxable in Canada nor in the U.S. 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, 2011, the Corporation incurred the following costs on its properties.

Costs Incurred Year Ended December 31, 2011 (\$)			
	Canada	United States	Total
Property Acquisition Costs			
Proved Properties	-	-	-
Unproved Properties	20,348	671,141	691,489
Exploration Cost	-	471,648	471,648
Development Cost	191,248	53,153	244,401
Corporate	596	-	596
	<u>212,192</u>	<u>1,195,942</u>	<u>1,408,134</u>

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, 2011.

		2011	
		Gross	Net
Canada			
Exploratory Oil wells	-	-	-
Developmental Oil wells	-	-	-
Exploratory Gas wells	-	-	-
Developmental Gas wells	1	.45	
Service wells	-	-	-
Dry wells	-	-	-
Total Canada	1	.45	
US			
Exploratory Oil wells	-	-	-
Developmental Oil wells	-	-	-
Exploratory Gas wells	-	-	-
Developmental Gas wells	-	-	-
Service wells	-	-	-
Dry wells	1.0	0.4	
Total US	1.0	0.4	

The main focus for exploration and development activities will be in the U.S. where a 3-D seismic program, followed up by oil exploratory drilling is planned for the next few years. There are no significant activities planned for Canada.

Production Estimates

The following tables set out the total volume of production estimated for the Corporation for the year ended December 31, 2011 reflected in GLJ's estimates of future net revenue (based on forecast prices and costs) from the evaluated gross proved reserves and gross probable reserves of MEC as disclosed in the tables set forth under "Reserves Data" above, together with information regarding the portion of that estimated production volume attributed to Canada and the U.S.

ESTIMATED PRODUCTION FOR 2012 - TOTAL FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2011

	Proved	Proved Plus Probable
2012 Production (Gross)		
Light and Medium Oil (bbl/d)	0	0
Heavy Oil (bbl/d)	2	2
Gas (mcf/d)	1,048	1,089
NGL (bbl/d)	0	0
BOE (bbl/d)	176	183
2012 Production (Net)		
Light and Medium Oil (bbl/d)	0	0
Heavy Oil (bbl/d)	1	1
Gas (mcf/d)	890	925
NGL (mcf)	0	0
BOE (bbl/d)	150	156

ESTIMATED PRODUCTION FOR 2012 - CANADA FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2011

	Proved	Proved Plus Probable
2012 Production (Gross)		
Light and Medium Oil (bbl/d)	0	0
Heavy Oil (bbl/d)	2	2
Gas (mcf/d)	372	380
NGL (bbl/d)	0	0
BOE (bbl/d)	64	65
2012 Production (Net)		
Light and Medium Oil (bbl/d)	0	0
Heavy Oil (bbl/d)	1	1
Gas (mcf/d)	349	356
NGL (bbl/d)	0	0
BOE (bbl/d)	60	61

ESTIMATED PRODUCTION FOR 2012 – U.S. FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2011

	Proved	Proved plus Probable
2012 Production (Gross)		
Light and Medium Oil (bbl/d)	0	0
Heavy Oil (bbl/d)	0	0
Gas (mcf/d)	676	710
NGL (bbl/d)	0	0
BOE (boe/d)	113	118

**ESTIMATED PRODUCTION FOR 2012 – U.S.
FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2011**

	Proved	Proved plus Probable
2012 Production (Net)		
Light and Medium Oil (bbl/d)	0	0
Heavy Oil (bbl/d)	0	0
Gas (mcf/d)	542	569
NGL (bbl/d)	0	0
BOE (boe/d)	90	95

Production History

The following table summarizes MEC'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 production in Canada.

	2011	Q4	Q3	Q2	Q1
Oil & NGL(bbls/d)	3	3	4	2	3
Natural Gas (mcf/d)	411	400	465	314	481
Total (boe/d)	72	70	82	54	84

The following table summarizes MEC'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 production in the U.S.

	2011	Q4	Q3	Q2	Q1
Oil & NGL (bbls/d)	-	-	-	-	-
Natural Gas (mcf/d)	820	830	831	751	866
Total (boe/d)	136	138	139	125	144

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:

	2011	Q4	Q3	Q2	Q1	2010	Q4	Q3	Q2	Q1
Product Prices										
Light & Medium Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil (\$/bbl)	60.58	87.53	31.84	109.36	49.41	54.19	48.70	51.29	50.76	62.88
Natural Gas(\$/mcf)	3.67	3.00	3.21	3.82	3.74	3.94	3.68	3.87	3.83	5.40
Net Royalties										
Light & Medium Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil (\$/bbl)	10.90	38.75	3.12	5.58	1.14	3.94	1.38	2.25	3.30	7.53
Natural Gas(\$/mcf)	0.57	0.42	0.56	0.87	0.49	0.55	0.57	0.32	0.54	0.76
Operating Expense										
Light & Medium Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil (\$/bbl)	42.79	27.46	25.69	62.49	67.45	8.88	9.31	9.52	10.36	7.05
Natural Gas(\$/mcf)	3.89	5.74	2.13	4.96	3.12	3.88	3.42	5.46	3.68	3.21

	2011	Q4	Q3	Q2	Q1	2010	Q4	Q3	Q2	Q1
Operating Netback										
Light & Medium Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil (\$/bbl)	6.89	21.32	3.03	41.29	(19.18)	41.37	38.01	39.52	37.10	48.30
Natural Gas(\$/mcf)	(0.79)	(3.16)	0.52	(2.01)	0.13	(0.49)	(0.31)	(1.91)	(0.39)	1.43

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.

	2011	Q4	Q3	Q2	Q1	2010	Q4	Q3	Q2	Q1
Product Prices										
Light & Medium Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Natural Gas(\$/mcf)	353	3.06	3.56	3.85	3.68	3.82	3.51	3.38	3.72	4.80
Net Royalties										
Light & Medium Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Natural Gas(\$/mcf)	0.50	(1.03)	1.00	1.07	1.01	1.06	0.97	0.94	1.04	1.35
Operating Expense										
Light & Medium Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Natural Gas(\$/mcf)	2.52	2.48	2.79	2.35	2.43	2.32	2.01	2.45	1.67	3.26
Operating Netback										
Light & Medium Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Heavy Oil (\$/bbl)	-	-	-	-	-	-	-	-	-	-
Natural Gas(\$/mcf)	0.51	1.61	(0.23)	0.43	0.24	0.44	0.53	(0.01)	1.01	0.19

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

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves.

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:

- (a) analysis of drilling, geological, geophysical and engineering data;
- (b) the use of established technology; and
- (c) 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.

Development and Production Status

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 subdivided 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:

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

Reserves must fully meet the requirements of the reserves classification (proved, probable, possible) 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 sub-divide the developed reserves for the pool between developed producing and developed nonproducing. 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.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

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 and the date each director became a director of the Corporation. Pursuant to the By-laws of the Corporation, all previously elected directors are deemed to retire from office at the time of the each shareholders' meeting.

Name and Municipality of Residence	Position Held and Date of Appointment as Director	Principal Occupations
Charles V. Selby ⁽⁴⁾ Calgary, Alberta, Canada	Chairman, Chief Executive Officer and Director since 1997	Chairman and Director of the Corporation; President of Caledonian Royalty Corp. and Caledonian Global Ltd.; Chairman and C.E.O. of Canadian Star Energy Ltd.; Director of Vecta Energy Corporation, Qwest Energy Group of Companies, NXT Energy Services Inc., and Idaho Resources Corp.
Donald E. Foulkes Calgary, Alberta, Canada	President and Director since 2002	President, CEO and Director of the Corporation; Director of Second Wave Petroleum Ltd., and Quadris Canada; CEO and Chairman of Bushmills Energy Corp. (2001 to 2002); CEO and Chairman of Causeway Energy Corp. (1998 to 2001).
Michael J. Hibberd ^{(1) (2) (3)} Calgary, Alberta, Canada	Director since 1997	President of MJH Services Ltd. (Corporate Finance Advisors) (1995 to present); Chairman of Heritage Oil PLC, Heritage Oil Corp., Greenfields Petroleum Corp. and Canacol Energy; Executive Co-Chairman of Sunshine Oilsands Ltd.; Director of Pan Orient Energy Corp. and Skope Energy Inc.;
John R. Moore ^{(1) (2) (3)} Priddis, Alberta, Canada	Director since 1997	President of J.R. Moore and Associates Ltd. (1998 to present).
James W. Collins ^{(1) (2) (3)} McAllen, Texas, United States of America	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.
Donald L. Jackson Calgary, Alberta, Canada	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).
Brian A. Page Calgary, Alberta, Canada	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.
Michael S. Perry	Vice President, Exploration	Vice President, Exploration of the Corporation since April, 2011. Owner and operator of Emerald Operating Company, an independent Denver based exploration and production company since 1992.

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Compensation Committee.
- (3) Member of the Reserves Committee.

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 MEC, as a group, beneficially own, or control or direct, directly or indirectly, 10,978,260 Common Shares or approximately 52% of the issued and outstanding Common Shares, 71,863,720 of the Series A Preferred Shares or approximately 33% of the issued and outstanding Series A Preferred Shares and 1,250,000 of the Series C Preferred Shares which are all of the of the issued and outstanding Series C Preferred 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. Charles V. Selby was an independent director of Wellpoint Systems Inc. from 2006 to 2011. Wellpoint Systems Inc. was placed into receivership by two of lenders on January 31, 2011 and the company was sold to P2 Energy Solutions following a coordinated sales process for the full amount of the outstanding indebtedness.

Mr. Michael J. Hibberd was an independent director of Challenger Energy Corp. from December 1, 2005 until September 16, 2009. Challenger Energy Corp. obtained a creditor protection order under the Companies' Creditors Arrangement Agreement providing for the acquisition by Canadian Superior Energy Inc. of Challenger Energy Corp. (0.51 of a Canadian Superior Energy Inc. common share for each Challenger Energy Corp. common share). On September 17, 2009, all common shares of Challenger Energy Corp. were exchanged for common shares of Canadian Superior Energy Inc. and all creditor claims were fully honoured. Further details can be found on the public record for Challenger Energy Corp. 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 the Common Shares or Convertible Preferred 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.

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.

Common Shares

The Corporation is authorized to issue one class of shares designated as "Common Shares" in an unlimited number. 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 Corporation is authorized to issue one class of shares designated as "First Preferred Shares" and one class designated as "Second Preferred Shares" in an unlimited number. The First Preferred Shares and Second 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.

Presently, the Series A Convertible Shares, Series B Convertible Shares and Series C Convertible Shares (the "Convertible Preferred Shares") are the only First Preferred Shares issued and no Second Preferred Shares have been issued.

Each Series A Preferred Share and Series B Preferred Share may be exchanged any time up to eighteen months following their issuance for either one-tenth of a Common Share and one-tenth a full warrant which may be exercised for a price of \$0.80 or a secured debenture in the principal amount of \$0.05 which bears interest at a rate of prime plus 2.5%. Each Series C Preferred Share may be exchanged any time up to eighteen months following their issuance for either one Common Share and warrant which may be exercised for a price of \$0.80 or a secured debenture in the principal amount of \$0.52 which bears interest at a rate of prime plus 2.5%.

Holders of the Convertible Preferred Shares are entitled to vote, receive dividends and to such assets of the Corporation upon liquidation or winding up as the holder of the Convertible Preferred Share would be entitled to had such holder converted its Convertible Preferred Shares into Common Shares.

PRIOR SALES

In 2011, the following securities of MEC which are outstanding but not listed or quoted on a marketplace were sold:

Date of issuance	Type of Security	Number of Securities Sold	Price of Issuance	Nature of Transaction
February 9, 2011	Series A Convertible First Preferred Shares	154,010,000	\$0.05	Private Placement
February 9, 2011	Series A Convertible First Preferred Shares	51,863,720	\$0.05	Debt for Shares
February 16, 2011	Series A Convertible First Preferred Shares	3,400,000	\$0.05	Private Placement
February 16, 2011	Series B Convertible First Preferred Shares	20,000,000	\$0.05	Private Placement
February 17, 2011	Series A Convertible First Preferred Shares	35,200,000	\$0.05	Private Placement
February 25, 2011	Series A Convertible First Preferred Shares	6,915,524	\$0.05	Debt for Shares
August 12, 2011	Series C Convertible First Preferred Shares	1,250,000	\$0.52	Private Placement

DIVIDEND POLICY

No dividends have been paid on the Common Shares or Convertible Preferred Shares in any of the three most recently completed financial years 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 TSXV under the symbol "MTZ". The trading symbol changed from ANG to MTZ on February 28, 2011. The Convertible Preferred Shares are not traded or quoted on any Canadian or foreign marketplace.

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 TSXV (information presented on a post-Consolidation basis).

		High	Low	Volume Traded
2011	January	0.90	0.65	77,500
	February	0.94	0.60	50,250
	March	0.95	0.51	54,327
	April	0.82	0.60	33,098
	May	0.75	0.56	68,250
	June	0.72	0.43	67,000
	July	0.82	0.47	136,685
	August	0.60	0.42	81,000
	September	0.55	0.41	515,990
	October	0.50	0.215	50,703
	November	0.40	0.15	42,800
	December	0.365	0.16	169,009

On February 28, 2011 the outstanding Common Shares of the Corporation were consolidated ten for one basis.

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Canada

Government Regulation

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and our oil and gas operations are subject to various Canadian federal, provincial, territorial, and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure and the exploration, development, production, handling, storage, transportation, and disposal of oil and gas, oil and gas by-products, and other substances and materials produced or used in connection with oil and gas operations.

More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, and royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of our operations. The Corporation cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Although the Corporation does not expect that these controls and regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Crude Oil

Producers of crude oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends, in part, on crude oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, other contractual terms, and the world price of oil. Oil may be exported from Canada pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving such export has been obtained from the National Energy Board (the "NEB"). Any oil exported under a contract of longer duration (to a maximum of 25 years) requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

Natural Gas

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities not exceeding 30,000 m³/day) are subject to an NEB order. Any natural gas exported under a contract of

longer duration (to a maximum of 25 years) or in larger quantities requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The Government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and other market considerations.

Pipeline Capacity

As a result of recent pipeline additions and expansions, an excess of natural gas pipeline capacity exists in western Canada, which provides for the ability to deliver all current production to natural gas sales markets.

Recent and ongoing expansions of existing crude oil pipelines combined with the commissioning of a new, larger diameter oil pipeline leaves the Western Canadian Sedimentary Basin with sufficient take away capacity to deliver product to oil markets for the foreseeable future.

Royalties and Incentives

General

For crude oil, natural gas and related production from Federal or Provincial government lands, the royalty regime is a significant factor in the profitability of our production. Crown royalties payable in respect of crown lands are determined by governmental regulation and are typically calculated as a percentage of the value of gross production. The value of the production and the rate of royalties payable generally depend on prescribed reference prices, well productivity, geographical location, the field discovery rate and the type of product produced.

Royalties payable on production from privately owned lands are determined by negotiations between the mineral owner and the resource owner, although production from such lands is subject to certain provincial taxes and royalties. Any such royalties (or royalty-like interests) are carved out of the working interest owner's interest through non-public transactions and are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

From time to time, provincial governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

The Alberta government implemented a new royalty framework effective January 2009, which included significant changes to the oil and gas royalty system. The framework established new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependent on the market price and production volumes. On March 11, 2010, the government of Alberta announced further adjustments to the royalty framework including a reduction in the maximum royalty rates effective January 1, 2011 and the permanent implementation of certain temporary incentive programs.

In November 2008, in connection with the implementation and phase-in of the new royalty framework, the Alberta government announced a five-year program of "transitional" royalty rates providing for lower royalties at certain price points in the initial years of a qualifying well's life. Under the transitional royalty program, companies drilling new natural gas and conventional oil wells at depths between 1,000 metres and 3,500 metres (3,281 feet and 11,483 feet) spud after November 19, 2008 had a one-time option, on a well-by-well basis, to elect for the production from such wells to be subject to the transitional royalty rates or those provided for under the new royalty framework. The option for producers to elect transitional royalties in respect of qualifying deep wells ended on December 31, 2010

and any wells spudded on or after January 1, 2011 are subject to the royalty rates discussed below. Wells that are subject to transitional royalty rates will automatically revert to the new royalty framework (now known simply as the Alberta royalty framework) rates on January 1, 2014.

Royalty rates for conventional oil currently range from 0% to 40% and royalty rates for natural gas (methane and ethane) currently range from 5% to 36%. Royalty rates for propane and butane are fixed at 30% and the rate for pentane is fixed at 40%. Condensate royalties are calculated on a basis similar to royalties for conventional oil and currently range from 0% to 40%.

The government of Alberta has also introduced a number of royalty reduction and incentive programs to encourage oil and gas exploration and development in Alberta, which include the following programs, among others, currently in effect:

- The Deep Oil Exploration Program (the "DOEP") and the Natural Gas Deep Drilling Program (the "NGDDP") are two programs that became effective on January 1, 2009. These programs provide up-front royalty adjustments to new wells. To qualify for such royalty adjustments under the DOEP, exploration wells must have a vertical depth greater than 2,000 metres with a Crown interest and must be spudded after January 1, 2009. These oil wells qualify for a royalty exemption on either the first \$1,000,000 of royalty or the first 12 months of production. The NGDDP applies to wells producing at a true vertical depth greater than 2,500 metres. The NGDDP has an escalating royalty credit in line with progressively deeper wells from \$625 per metre to a maximum of \$3,750 per metre and there are additional benefits for the deepest wells. Both the DOEP and the NGDDP were originally announced as five year programs with any wells spudded after December 31, 2013 or any wells selecting the transition option not able to qualify. No royalty adjustments will be granted under the DOEP after December 31, 2018. On May 27, 2010 the NGDDP was made a permanent feature of the royalty regime and was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, among other changes;
- The new well royalty program that provides a maximum 5% royalty rate for the first 12 months of production from new wells that begin producing oil or natural gas between April 1, 2009 and March 31, 2010 to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. As of March 11, 2010, the Alberta government made the new well front-end royalty rate a permanent feature of the royalty system;
- Horizontal gas wells will receive a maximum royalty of 5% for 18 producing months up to 500 million cubic feet of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

In conjunction with the release of the new royalty curves for the Alberta royalty framework, the Alberta government also announced its Emerging Resources and Technology Initiative intended to accelerate new technologies and encourage the development of unconventional resources. The Emerging Resources and Technology Initiative will be reviewed in 2014 and the Alberta government has committed to provide industry three years notice if it intends to discontinue the program.

Natural Gas Liquids

The price of NGLs sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on the quality of the NGLs, prices of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGLs exported from Canada are subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. NGLs may be

exported for a term of not more than one year in respect of propane and butane and not more than two years in respect of ethane – with all exports requiring an order of the NEB.

Land Tenure

Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses, and permits and regulations as legislated by the respective Provincial and Federal governments. Lease terms vary in length, usually from two to five years. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Jurisdictions in western Canada have legislation in place for mineral rights reversion to the Crown where formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for non-productive lands, having met certain criteria as laid out in the relevant legislation.

Oil and natural gas can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

As an operator of oil and natural gas properties in Canada, the Corporation is subject to stringent federal, provincial, territorial, and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas exploration, production, and transportation operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper abandonment of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of capital or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

The Corporation currently operates or leases, and has in the past operated or leased, a number of properties that have been used for the exploration and production of oil and gas. Although the Corporation utilizes and has utilized standard industry operating and disposal practices, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by the Corporation or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Corporation's control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed wastes or remediate property contamination, or to perform well plugging or pit closure or other actions of a remedial nature to prevent future contamination.

The Corporation believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. A recent example of this trend is the high-level of regulatory attention that the practice of hydraulic fracturing continues to receive in various jurisdictions. The Province of Alberta has recently announced its intention to adopt mandatory disclosure requirements and an online registry for hydraulic fracturing activities and ingredients similar to the program already in force in the Province of British Columbia. While the Corporation believes that it is in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on the Corporation, Second Wave cannot give any assurance that it will not be adversely affected in the future. The Corporation has established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which it operates.

Greenhouse Gases and Industrial Air Pollutants

Canada (Federal)

Internationally, Canada is a signatory to the United Nations Framework Convention on Climate Change and previously ratified the Kyoto Protocol established thereunder, which set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide, and other GHGs. The first commitment period under the Kyoto Protocol is the five year period from 2008-2012. In December 2011, the Canadian Federal government announced that it would not agree to a second commitment period under the Kyoto Protocol after 2012. The Federal government instead endorsed the Durban Platform, a broad agreement reached among the 194 countries that are party to the United Nations Framework Convention on Climate Change, during a conference held in Durban, South Africa in December 2011. The Durban Platform sets forth a process for negotiating a new climate change treaty that would create binding commitments for all major GHG emitters. The Canadian government expressed cautious optimism that agreement on a new treaty can be reached by 2015. The Durban Platform followed the Copenhagen Accord reached in December 2009 as government representatives met in Copenhagen, Denmark to negotiate a successor to the Kyoto Protocol. The Copenhagen Accord represents a broad political consensus and reinforces commitments to reducing GHG emissions but is not a binding international treaty. Although Canada had committed under the Copenhagen Accord to reduce its GHG emissions by 17% from 2005 levels by 2020, the target is not legally binding. The impact of Canada's withdrawal from the Kyoto Protocol on prior GHG emission reduction initiatives is uncertain.

Domestically, the Canadian Federal government released in 2007 its Regulatory Framework for Air Emissions, which was updated in March 2008 in a document entitled "Turning the Corner: Regulatory Framework for Industrial Greenhouse Emissions." Canada's previous GHG emission reduction target was 20% from 2006 levels by 2020, but on January 30, 2010 the Canadian Federal government announced a new GHG emission reduction target consistent with its commitment under the Copenhagen Accord to reduce GHG emissions to 17% below 2005 levels by 2020. Canada's framework proposes mandatory emissions intensity reduction obligations on a sector-by-sector basis. Although implementing regulations are required, to date only regulations for Canada's transportation and electricity sectors have been developed. In 2009, the Canadian Federal government announced its commitment to work with the Provincial governments to implement a North America-wide cap and trade system for GHG emissions, in cooperation with the United States, under which Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. The government of Canada currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether or when either Canadian Federal GHG regulations for the oil and gas industry or an integrated North American cap-and-trade system will be implemented, what obligations might be imposed under any such system, or how they may ultimately affect our operations and financial results.

Alberta

Alberta introduced the *Climate Change and Emissions Management Act*, which provides a framework for managing GHG emissions by reducing specified gas emissions, relative to gross domestic product, to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulations include the Specified Gas Emitters Regulation (the "SGER"), which imposes GHG emissions limits, and the Specified Gas Reporting Regulation (the "SGRR"), which imposes GHG emissions reporting requirements.

The SGER, effective July 1, 2007, applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (i.e. the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000 or have completed eight years of commercial operation, and "new" facilities that have completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004, and 2005, and for a new facility emissions intensity in the third year of commercial operation. For an established facility, the required reduction in GHG emissions is 12% per year from its baseline, and such reduction must be maintained over time. For a new facility, the required reduction

from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the annual 12% reduction requirement is reached, and once reached such 12% reduction must be maintained over time.

There are three methods for operators of facilities that are subject to the SGER to comply with the annual emission intensity reduction requirements: (i) improve emissions intensity at the facility; (ii) purchase emission performance or emission offset credits in the open market, which are generated from Alberta based projects; and/or (iii) purchase “fund credits” by contributing to the Alberta Climate Change and Emissions Management Fund (“Fund”) run by the Alberta government. Historically the contribution costs to the Fund have been set at \$15/tonne of Co_{2e} although that has recently changed and the contribution costs are now set by order of the government of Alberta. Compliance reports for facilities subject to the SGER are due to Alberta Environment on March 31 annually.

The SGRR imposes GHG emissions reporting requirements on facilities that have GHG emissions of 50,000 tonnes or more in a year. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under other environmental regulations.

United States

MEC’s Montana oil and natural gas operations are regulated by administrative agencies under statutory provisions of the state of Montana and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. MEC’s Montana operations are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

Crude oil and natural gas located in the U.S. is predominantly owned by private owners. The Federal Government (Bureau of Land Management), Bureau of Indian Affairs and the state in which the minerals are located also may hold ownership to such rights. These owners, from governmental bodies to private individuals, grant rights to explore for and produce oil and gas pursuant to leases, licenses and permits for varying periods and on conditions including requirements to perform specific work or make payments. As to those rights held by private owners, all terms and conditions may be negotiated. For those rights held by governmental agencies, typically the terms and conditions of the oil and gas lease have been predetermined by each governing or regulatory body.

A lease may generally be continued after the initial term provided certain minimum levels of exploration or production have been achieved and all lease rentals have been timely paid, subject to certain exceptions. In order to develop minerals, including oil and gas, it is necessary for the mineral estate owner to have access to the surface estate. Under common law, the mineral estate is considered the “dominant” estate with the right to extract minerals subject to reasonable use of the surface. Each state has developed and adopted their own statutes that operators must follow both prior to drilling and following drilling including notification requirements and to provide compensation for lost land use and surface damages. The surface rights required for pipelines and facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

In addition to federal regulations, Montana has legislation and regulations which govern oil and gas land holdings, royalties, production rates, environmental protection and other matters. In Montana, producers of oil and natural gas are typically required to pay annual rental payments in respect of federal, state and freehold leases until production begins. Upon commencement of production, royalties and production taxes are paid in respect of oil and natural gas produced from federal, state and freehold lands. The royalty and production tax regime is a significant factor in the profitability of oil and natural gas production.

Royalties payable on production from lands other than federal and state lands are determined by negotiations between the freehold mineral owner and the lessee. Federal and state royalties and production taxes are determined

by government regulation and are generally calculated as a percentage of the value of the gross production. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties or net profits or net carried interests.

From time to time, the federal and state governments in the U.S. have established incentive programs which have included royalty rate or production tax rate reductions (including for specific wells), royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. If applicable, oil and natural gas royalty holidays, reductions and tax credits would effectively reduce the amount of federal and state royalties or taxes paid by oil and gas producers to the governmental entities.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Prices, Markets and Marketing

The marketability and price of oil and natural gas acquired or discovered is and 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 relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and gas business 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 and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

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.

Substantial Capital Requirements and Financing

The Corporation anticipates making substantial capital expenditures for the exploration, development and production of oil and natural gas reserves, including the potential acquisition of additional oil and natural gas properties. The Corporation's working capital and cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. If the Corporation's revenues or reserves decline, it may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation financial condition, results of operations or prospects.

The Corporation does not presently have sufficient financial resources to undertake by itself all of its development programs beyond 2012. The exploration and development of the Corporation's properties depend, therefore, on MEC's ability to obtain additional financing through equity financing, joint ventures, debt financing or other means. Failure to obtain any financing necessary for MEC's capital expenditure plans may result in a delay in development or production on MEC's properties. There can be no assurance that the Corporation's efforts to raise such funding will be successful, or achieved on terms favourable to the Corporation or its existing shareholders. The failure of MEC to obtain additional financing on a timely basis or on terms favourable to the Corporation could result in the loss or substantial dilution of the Corporation's interests (as existing or as proposed to be acquired) in its properties.

There can be no assurance that cash flow from operations will be adequate to meet the financial obligations of the Corporation or, if required, that additional funds can be obtained.

Exploration, Development, Exploitation and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered, acquired or developed by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of acquisition, drilling, completion and operating costs. In addition, drilling hazards, mechanical failures or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production 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.

Project Risks

The Corporation will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond the Corporation's control, including: (i) the availability of processing capacity; (ii) the availability and proximity of pipeline capacity; (iii) the availability of storage capacity; (iv) the supply of and demand for oil and natural gas; (v) the availability of alternative fuel sources; (vi) the effects of inclement weather; (vii) the availability of drilling and related equipment; (viii) unexpected cost increases; (ix) accidental events; (x) currency fluctuations; (xi) changes in regulations; (xii) the availability and productivity of skilled labour; and (xiii) the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Reserve Estimates

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, 2011 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.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective

as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Competition

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 and storage. Competition may also be presented by alternative fuel sources.

Seasonality

The level of activity in the Canadian and the United States of America oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Accounting

The Corporation uses International Financial Reporting Standards to account 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.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar have negatively impacted the Corporation's production revenues. Further material increases in the value of the Canadian dollar would exacerbate this negative impact. This increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Common Shares.

Hedging

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 and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving

effect to such agreements. Similarly, 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.

Availability of Drilling Equipment and Access

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.

Title to Assets

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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies may operate some of the assets in which the Corporation has an interest. As a result, the Corporation will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others will therefore depend upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Need to Replace and Grow Reserves

Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted. The business of discovering, developing and acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, the ability of MEC to make the necessary capital investments to maintain and expand its oil and natural gas reserves will be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace production at commercially reasonable costs.

Issuance of Debt

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. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Foreign Activities

Many of the Corporation's oil and gas assets are located in the United States of America. As such, MEC is subject to political, economic, and other uncertainties not within its control, including, but not limited to the uncertainty of negotiating with foreign governments, adverse legislation in the United States of America, renegotiation or nullification of existing concessions, adverse determinations or rulings by governmental authorities, changes in energy policies or in the personnel administering them, disputes between various levels of authorities, arbitrating and enforcing claims against entities that may claim sovereignty, authorities claiming jurisdiction, potential implementation of exchange controls and royalty and government take increases and other risks arising out of foreign governmental sovereignty over the areas in which MEC's operations are conducted.

The Corporation's international operations and investments may also be adversely affected by laws and policies of Canada affecting foreign trade, taxation and investment. In the event of a dispute arising in connection with its foreign operations, MEC may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada or enforcing Canadian judgments in foreign jurisdictions. Consequently, the Corporation's foreign activities could be substantially affected by factors beyond its control, any of which could have a material adverse effect on MEC.

Regulatory

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. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's intended business, financial condition and results of operations. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental

laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by new legislation or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition.

Conflicts of Interest

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.

Reliance on Key Personnel

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 effect 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.

General Economic Trends

On a worldwide scale, the capital markets have been experiencing weakness and volatility. The collapse of the global capital markets in 2008 and its aftermath may have an adverse effect on the ability of the Corporation to raise additional capital on a timely basis and on terms that would be acceptable and will generally impact the quality of the shareholders' investment in the Common Shares. Some experts believe that the global economic crisis will persist for an extended period of time and as such, the operations of the Corporation and the quality of the shareholders' investment therein may be adversely affected and such factors may have a negative impact on the value, the holding period and the resale of the securities of the Corporation.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on the Corporation. The Corporation will not have insurance to protect against the risk from terrorism.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licenses and leases and working interests in licenses and leases. If the Corporation or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of the Corporation's licenses or leases or the working interests relating to a license or lease may have a material adverse effect on the Corporation's results of operations and business.

Dividends

To date, the Corporation has not declared or paid any dividends on the outstanding Common Shares or Convertible Preferred Shares. Any decision to pay dividends on the Common Shares or Convertible Preferred Shares will be made by the Board on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. At present, the Corporation does not anticipate declaring and paying any dividends in the near future.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and the United States of America. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful this could have an adverse effect on the Corporation and its operations.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

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.

On June 18, 2010, ANG Partners, Ltd. ("**ANG**"), a corporation controlled by James Collins, exercised rights pursuant to the Rights Letter and received 71,714,285 Pre-consolidation Common Shares priced at \$0.07 in return for the surrender of \$2,519,650 of convertible debentures and cash payment of \$2,500,350.

In November 2009 and November 2010, ANG loaned \$800,000 and \$300,000, respectively, to the Corporation. In February 2011, ANG Partners, Ltd. was issued 51,863,720 Series A Preferred Shares at \$0.05 per share in order to settle \$2,593,186 of debt. The debt consisted of \$1,625,000 constituting 50% of the Bridging Loan Facility, the November 2009 loan of \$800,000 and accrued interest on these loans in the amount of \$168,186.

In February 2011 and August 2011, ANG. subscribed for 20,000,000 Series A Preferred Shares and 1,250,000 Series B Preferred at a price of \$0.05 and \$0.52. respectively.

In March 2012, Rioco Partners Ltd. ("**Rioco**"), a limited partnership controlled by Jim Collins, a director and largest shareholder of MEC, assumed the entire balance of the credit facility from the company's principal lender, a Canadian chartered bank, through payment of approximately \$2.4 million. The Corporation has agreed in principle with Rioco to extend the term of the facility to March 1, 2014. Subject to approval of the TSXV, it is proposed that, in consideration for the extension of the credit facility and the elimination of some of its covenants, Rioco will be issued 4,000,000 warrants, each warrant entitling the holder to purchase one common share of the company at an exercise price of \$0.32 for a period of 24 months until March 1, 2014, and the credit facility will be amended to permit the conversion of the principal amount owed under the credit facility to common shares of the company at a conversion rate of \$0.32.

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.

MATERIAL CONTRACTS

The only material contracts entered into by MEC during the most recently completed financial year, or before the most recently consolidated fiscal year that are still in effect, other than in the ordinary course of business, are the following:

- The Rights Letter;
- the agreement in respect of the \$5.7 million (reduced to \$2.5 million August 15, 2011) revolving credit facility; and
- Bridge Loan Facility.

Copies of each material contract is available on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than GLJ (the independent reserve evaluator), and PricewaterhouseCoopers LLP (the Corporation's auditors). None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. PricewaterhouseCoopers LLP is independent in accordance with the auditors' rules of professional conduct in Canada.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

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.

SCHEDULE A

Report on Reserves Data by Independent Qualified Reserves Evaluator on Form 51-101F2

To the board of directors of Montana Exploration Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, 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 misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented 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, 2011, 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	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M\$)			
			Audited	Evaluated	Reviewed	Total
	Corporate Summary					
GLJ Petroleum Consultants	March 16, 2012	Canada	-	1,338	-	1,338
GLJ Petroleum Consultants	March 16, 2012	U.S.	-	676	-	676
Totals				2,014		2,014

5. In our Opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
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.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 22, 2012

"original signed"

Myron J. Hladyshevsky, P. Eng.
Vice President

SCHEDULE B

Report of Management and Directors On Oil and Gas Disclosure on Form 51-101F3

Management of Montana Exploration 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 are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

An independent qualified reserves evaluator, GLJ Petroleum Consultants Ltd ("GLJ") has evaluated the Corporation's reserves data. The report of GLJ will be filed with securities regulatory authorities concurrent with this report.

The Reserves Committee of the Board of Directors of the Corporation has reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator; confirmed that a Corporation representative has met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent reserves evaluator to report without reservation; and reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors 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 of Directors has, on the recommendation of the Reserves Committee, 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 Form 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 judgments regarding future events, actual results may vary and the variations may be material.

"original signed"

Charles V. Selby, Executive Chairman
& Director

"original signed"

Donald E. Foulkes, President, CEO, & Director

"original signed"

Michael J. Hibbard, Director

"original signed"

Donald L Jackson, Executive Vice President & COO

"original signed"

John R. Moore, Director

April 30, 2012