QUESTERRE ENERGY CORPORATION

Annual Information Form

For the Year Ended December 31, 2009

March 25, 2010

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ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
MMbbl	million barrels
bbl/d	barrels per day
API	American Petroleum Institute
NGLs	natural gas liquids
stb	standard stock tank barrel
Mstb	thousand standard stock tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
bcf	billion cubic feet
Tcf	trillion cubic feet
MMbtu	million British thermal units
gj	gigajoule
gj/d	gigajoules per day
m^3	cubic metres

Other

boe	barrel of oil equivalent converting six Mcf of natural gas to one barrel of oil (6:1)
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
M$	thousands of dollars
MM$	millions of dollars
NPV	net present value
OPEC	Organization of the Petroleum Exporting Countries
GAAP	Generally accepted accounting principles applied on a consistent basis

In this Annual Information Form the calculation of barrels of oil equivalent (boe) is calculated at a conversion rate of six thousand cubic feet (6 Mcf) of natural gas for one barrel (bbl) of oil based on an energy equivalency conversion method. Boe's may be misleading particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1bbl is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead.

PRESENTATION OF OIL AND GAS INFORMATION

All oil and gas information contained in this Annual Information Form and the documents incorporated by reference herein, has been prepared and presented in accordance with NI 51-101. The actual oil and gas reserves and future production will be greater than or less than the estimates provided herein. The estimated value of future net revenue from the production of the disclosed oil and gas reserves does not represent the fair market value of these reserves. There is no assurance that the forecast prices and costs or other assumptions made in connection with the reserves disclosed herein will be attained and variances could be material.

Estimates of resources always involve uncertainty, and the degree of uncertainty can vary widely between accumulations/projects and over the life of a project if discovered. Resources herein have been provided as low, best and high estimates as follows:

- **Low Estimate**: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the low estimate.

- **Best Estimate**: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability that the quantities actually recovered will equal or exceed the best estimate.

- **High Estimate**: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability that the quantities actually recovered will equal or exceed the high estimate.

CURRENCY

In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. 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. The Corporation believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be. The Corporation does not intend, and does not assume any obligation, to update or revise these forward-looking statements except as required pursuant to applicable securities laws.

Forward-looking information and statements are included throughout this Annual Information Form (and the documents incorporated by reference herein) including under the headings "General Development of the Business", "Statement of Reserves Data and Other Oil and Gas Information", "Additional Information Relating to Reserves Data", "Other Oil and Gas Information", "Risk Factors" and "Industry Conditions" and include, but are not limited to, statements pertaining to the following:

- the Corporation's resource estimates;
- any estimate of present value or future net cashflow;
- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- plans for facilities construction and completion and the timing and method of funding thereof;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- drilling, completion and facilities costs;
- results of various projects of Questerre;

- timing of receipt of regulatory approvals;
- effect of production increases on operating costs per boe;
- ability to lower cost structure in certain projects of Questerre;
- growth expectations within Questerre;
- timing of development of undeveloped reserves;
- the tax horizon and taxability of Questerre;
- supply and demand for oil, natural gas liquids and natural gas;
- the performance and characteristics of Questerre's oil and natural gas properties;
- Questerre's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the impact of Canadian federal and provincial governmental regulation on Questerre relative to other oil and gas issuers of similar size;
- realization of the anticipated benefits of acquisitions and dispositions;
- weighting of production between different commodities;
- the quantity and quality of the oil and natural gas reserves;
- projections of commodity prices and costs;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- bankruptcy finalization for the Magnus entities;
- timing and extent of work programs by the Corporation’s partners, Talisman Energy Inc. and Forest Oil Corporation, in the St. Lawrence Lowlands, Québec;
- capital expenditure programs and the timing and method of financing thereof; and
- treatment under government regulation and taxation regimes.

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 Annual Information Form:

- general economic conditions in Canada, the United States and globally including reduced availability of debt and equity financing generally;
- industry conditions, including fluctuations in the price of oil, natural gas liquids and natural gas;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- uncertainties associated with estimating oil and natural gas reserves;
- uncertainties in the estimates of the Corporation’s resources;
- incorrect assessments of the value of acquisitions;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to realize anticipated benefits of acquisitions;
- failure to obtain industry partner and other third party consents and approvals, when required;
- stock market volatility and market valuations;
- availability of capital on acceptable terms;

- competition for, among other things, capital, acquisitions or reserves, undeveloped land and skilled personnel;
- competition for and inability to retain drilling rigs and other services;
- rights to surface access;
- the need to obtain required approvals from regulatory authorities;
- general business and market conditions; and
- the other factors considered under "Risk Factors" in the Annual Information Form and other risk factors identified in other documents incorporated herein by reference.

These factors should not be considered exhaustive. Statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. With respect to forward-looking statements contained or incorporated by reference in this Annual Information Form, Questerre has made assumptions regarding: future exchange rates; energy markets and the price of oil and natural gas; the impact of increasing competition; condition in general economic and financial markets; availability of drilling and related equipment; availability of skilled labour; availability of prospective drilling rights; current technology; cash flow; commodity prices; production rates; effects of regulation and tax laws by governmental agencies; future operating costs and the Corporation's ability to obtain financing on acceptable terms. In addition, forward-looking statements in documents incorporated by reference herein may be based on additional assumptions as disclosed in such documents. Readers are cautioned that the foregoing list of factors is not exhaustive.

The above summary of assumptions and risks related to forward-looking information has been provided in this Annual Information Form and the documents incorporated by reference herein in order to provide readers with a more complete perspective on Questerre's future operations. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement.

THE CORPORATION

Questerre Energy Corporation ("**Questerre**" or the "**Corporation**") was incorporated under the *Companies Act* (Alberta) on October 25, 1971 under the name "Westpro Equipment Ltd." and continued under the *Business Corporations Act* (Alberta) (the "**ABCA**") on December 13, 1982. On July 13, 1990, the Corporation was continued under the *Companies Act* (British Columbia). On December 5, 2000, the Corporation was continued from British Columbia to Alberta under the ABCA and its name was changed to "Questerre Energy Corporation". On June 26, 2003, the issued common shares were subdivided into three new common shares ("**Common Shares**") for each old common share of the Corporation.

The principal, head and registered office of the Corporation is located at Suite 1650, 801 - 6th Avenue S.W., Calgary, Alberta T2P 3W2.

Intercorporate Relationships

The Corporation has three direct wholly-owned subsidiaries, Questerre Beaver River Inc. ("**QBR**") and Magnus Energy Inc. **("Magnus")**, each incorporated under the ABCA and 6058931 Canada Inc., which was incorporated under the Canada Business Corporations Act.

Magnus has one wholly-owned subsidiary, Magnus One Energy Corp., which was incorporated under the ABCA.

GENERAL DEVELOPMENT OF THE BUSINESS

Business of the Corporation

Questerre is actively engaged in the exploration for, and the development, production and acquisition of oil and gas projects, particularly shale gas in North America. Management of Questerre intends to leverage its knowledge of unconventional gas reservoirs to develop these projects. Questerre is currently working to establish commerciality of its Utica shale gas play in Québec. Questerre holds assets in British Columbia, Alberta, Saskatchewan, Manitoba and Québec.

Corporate Strategy

Management of Questerre intends to leverage its knowledge of unconventional gas reservoirs to develop these projects.

To mitigate the financial and operational risks associated with these projects, the Corporation often seeks industry partners to jointly participate in their development. The Corporation plans to further diversify risk through the acquisition and development of a portfolio of lower risk projects. It is expected these lower risk projects will provide near-term cash flow and growth.

History of the Corporation

Questerre initially operated as an oil and gas exploration and production company with minority interests in several producing properties in Western Canada. In November 2000, a new management team was assembled and Questerre changed its focus to pursuing what management believes will be scalable high-impact projects in Canada.

The Corporation acquired an interest in two projects in 2001 – the Beaver River Field (the "**Field**") located in northeast British Columbia and the St. Lawrence Lowlands (the "**Lowlands**") situated in Québec. See "Principal Properties".

In February 2004, Questerre completed operations on the re-entry of the A-5 well at the Field. QBR had a 100% working interest in this well as its partners elected to forego participation under a 600% penalty. Due to operational problems, the well took substantially longer than expected. Tie-in to production facilities and the field gathering system was completed in March 2004 and the well was placed on production shortly thereafter. The well results were significantly below management's expectations.

The unsuccessful results of the A-5 re-entry were compounded by significant operational delays and cost overruns. The total project costs, including completion, testing and tie-in, were over $19 million, or almost three times the original cost estimate. With over $9 million remaining unpaid to unsecured trade creditors as a result of these overruns, on April 1, 2004, QBR applied for and was granted an order by the Court of Queen's Bench of Alberta providing for creditor protection under the *Companies' Creditors Arrangement Act* ("**CCAA**"). The filing under CCAA was intended to allow QBR to restructure its affairs while continuing operations on a normalized basis.

In May 2004, the Corporation reached an agreement with Gastem Inc. ("**Gastem**"), a Montreal-based junior exploration company and Hydro-Quebec ("**Hydro**") regarding Questerre's exploration licenses in the Lowlands. Questerre held exploration licenses covering 719,000 acres of land in the Lowlands. Questerre held an 85% working interest in 13 of these licenses and a 70% working interest in three of these licenses. Terrenex Acquisition Corporation ("**TAC**"), a corporation with common directors and officers held a 15% working interest in all the licenses.

Pursuant to the terms of the agreement, Hydro and Gastem would fund 75% of the drilling costs of a single well to earn a 50% interest in the well and 2,000 surrounding hectares. Both Gastem and Hydro would have a rolling option under this agreement to drill additional wells on the same terms within six months of completion of the initial well. During the same month, the Corporation concluded a participation agreement with a former director of the Corporation to participate in this well on the same terms and conditions to earn a 10% working interest.

In June 2004, the Corporation concluded a financing agreement with Rupert's Crossing, an Investment Corporation ("**Rupert's**"). Rupert's is a private investment company controlled by the President and Chief Executive Officer of Questerre. The Corporation issued a $0.6 million promissory note on the receipt of $0.6 million from Rupert's in 2004.

On June 22, 2004, the Corporation was granted protection under the CCAA and was added as a petitioner in QBR's CCAA proceedings. The filing was made to facilitate concurrent Plans of Compromise or Arrangement (the "**Plans**" or "**Plans of Arrangement**") for the settlement of all claims filed in connection with the A-5 re-entry.

On August 9, 2004, the Corporation and QBR filed the Plans. The Plans were approved by the requisite majority of unsecured creditors at meetings of creditors of QBR and the Corporation held on August 31, 2004. The Plans were subsequently sanctioned by the Court of Queen's Bench of Alberta on September 9, 2004 and implemented shortly thereafter. A total of $0.56 million in cash and 9,623,012 Common Shares were issued in connection with the Plans. 6,756,102 Common Shares were issued to TAC in consideration for financing a cash payment to the creditors. Following the corporate restructuring, the Corporation began diversifying its portfolio of assets to include conventional projects in Alberta. In November 2004, the Corporation acquired an interest in two projects in Alberta. It acquired a 50% interest in 6,400 acres in the Simonette area of West Central Alberta. It also concluded a farm-in and participation agreement in the Parkland and Vulcan areas of Southern Alberta.

In December 2004, the Corporation completed a private placement of 2,638,000 Common Shares at $0.25 per Common Share and 9,825,000 flow-through Common Shares at $0.30 per Common Share for gross proceeds of $3.61 million. Proceeds from this private placement were primarily used to finance acquisition and drilling of new projects in Alberta, namely Simonette and Parkland and Vulcan.

The Corporation participated in the drilling of a well in the Simonette area of Alberta during the first quarter of 2005 with Cabot Petroleum Canada Corporation. The well was testing a Swan Hills reef play adjacent to two fields that produced in excess of 15 million barrels each from the Swan Hills formation. The well did not encounter the reservoir in the Swan Hills formation and was subsequently abandoned. Questerre farmed out a 26.7% interest (20% after payout) in this well to Devon ARL Corporation and retained a 23.3% interest (30% after payout) in this well.

In April 2005, Questerre completed a private placement for gross proceeds of $1 million through the issuance of 3,125,000 Common Shares at $0.32 per Common Share.

In April 2005, the Corporation entered into an agreement with Rupert's to acquire its interest in certain producing properties and acreage in the Westlock and Hector areas of Central Alberta. The purchase price for this acquisition of $2.1 million was based on an evaluation of these assets prepared by an independent reservoir engineering firm. The acquisition closed during the second quarter of 2005 with an effective date of April 1, 2005.

In May 2005, QBR entered into a royalty and quitclaim agreement ("**Quitclaim Agreement**") with its partners at the Field (the "**Farmors**") and Ampac Petroleum Inc. ("**Ampac**"). Ampac is a private exploration and production company controlled by a former director of Questerre. Pursuant to the Quitclaim Agreement, the Farmors quitclaimed their interest in the Field to Ampac and QBR in consideration of a royalty and a release by QBR of any amounts owed under the original farmout agreement dated January 12, 2001 (the "**Beaver River Agreement**"). QBR and Ampac would assume all liabilities associated with the Farmors' interest in the Field. The respective interests of QBR and Ampac in the Field post the quitclaim were 66.67% and 33.33%. Upon the execution of this Quitclaim Agreement, QBR and the Farmors agreed to terminate the Beaver River Agreement.

In May 2005, QBR and Ampac entered into a farmout and operating agreement ("**Ampac Farmout Agreement**") for the Field. Pursuant to the Farmout Agreement, Ampac would conduct an initial work program ("**Initial Work Program**") involving the re-entry of four wells to earn a 50% interest in the drilling spacing units of the wells for the shallow Mattson horizon. The second phase would involve two optional wells. Upon the completion of the Initial Work Program and the two optional wells, Ampac will hold a 50% interest in the Field, including all horizons, infrastructure and equipment. If Ampac did not complete the two optional wells, it would transfer its interest in the Field, excluding the interest earned under the Initial Work Program to QBR. Ampac subsequently farmed out this agreement to Transeuro Energy Corp. ("**Transeuro**"), an emerging international oil and gas company. The first phase of this development commenced in September 2005 and operations on three of the four wells were finalized by March 2006.

In June 2005, Questerre completed a $10 million offering and listed its Common Shares for trading on the Oslo Stock Exchange in Norway. A total of 30,000,000 Common Shares were issued at $0.33 per Common Share under the offering primarily to retail and institutional investors in Norway.

In June 2005, the Corporation entered into a farm-in agreement with Gastem for its exploration acreage in Quebec (the "**Yamaska**" and "**St. Jean**" properties). Pursuant to this agreement, Questerre would earn a 50% interest in seven exploration licenses covering 311,872 acres held by Gastem by funding a prescribed work program. This agreement was subsequently terminated and the Companies entered into two separate agreements in July 2006 and October 2006 for this acreage.

In July 2005, the Corporation terminated the Gastem Farmout Agreement with Gastem and Hydro as these parties were unable to spud the test well by July 15, 2005.

In September 2005, the Corporation completed a private placement of 9,987,690 Common Shares at $0.82 per Common Share for gross proceeds of $8.19 million.

In October 2005, Questerre executed a definitive agreement with Talisman Energy Inc. ("**Talisman**") for its existing 719,000 acres in the St. Lawrence Lowlands (the "**Talisman Farmout**"). At its sole cost, Talisman commenced a 2-D seismic program over two Questerre prospects in early 2006. Based on the results of the program Talisman had the right to drill up to four wells to earn on all the acreage. Questerre and its partners may retain a 25% working interest in the acreage and receive a 5% gross overriding royalty from Talisman. The Corporation and its partners were responsible for 15% of the drilling costs with Talisman funding the remainder of the drilling and other land, geological and geophysical costs.

In 2005, Questerre participated in a new Mannville pool discovery in the Vulcan area of Southern Alberta. Questerre has a 50% interest in this new pool discovery. Three wells were drilled into the pool in 2005.

In January 2006, Questerre acquired an interest in Gastem by subscribing, on a private placement basis, for 1.46 million units of Gastem. Each unit consisted of 1 common share of Gastem and one warrant. Each warrant entitles the holder to acquire one additional common share of Gastem at $0.10 per share for two years.

In February 2006, Questerre completed a private placement of 11 million Common Shares at $0.65 per Common Share for gross proceeds of $7.15 million.

In April 2006, Questerre acquired Stride Energy Ltd. ("**Stride**"), a private exploration and production company with land and production focused in the Westlock area of Central Alberta. Stride held 16,640 gross acres and production of approximately 227 boe/d. Stride shareholders elected to receive either $2.4092/share in cash or 2.834 Common Shares or a combination thereof subject to a maximum of $6,282,000 and a maximum of 7,262,856 Common Shares. Total consideration for this acquisition was $6.28 million in cash and 7,262,742 common shares. Stride was subsequently amalgamated with QBR.

In May 2006, the Corporation concluded a farm-in agreement with a major independent covering 21,120 acres of land in Westlock. Pursuant to the terms of the farm-in agreement, Questerre would fund an initial five well program to earn a majority working interest in ten sections of the farmor's land. Questerre had the option to drill additional wells to earn an interest on the same terms.

In June 2006, the Corporation completed a private placement of 9,709,000 Common Shares issued on a flow-through basis at $1.03 per Common Share for gross proceeds of $10 million. The Corporation also granted the agents an option to acquire 291,270 Common Shares at $1.03 per share until December 28, 2007.

Following its 2-D seismic acquisition program, Talisman spud Gentilly #1, its first well on Questerre's acreage, in October 2006. As a result of its election to participate and its carried working interest, Questerre paid 10.5% of the well costs to retain a net 17.5% working interest in the well. Questerre will also receive an overriding royalty on any production from the well. The well was drilled to a vertical depth of 2529m and was tested in early 2007.

In December 2006, 14,000,000 Common Shares were issued pursuant to a private placement at $1.34 per share for gross proceeds of $18.8 million.

In 2006, Questerre's primary focus in Alberta was the development of its core area in Vulcan. A total of 12 wells were drilled targeting multiple horizons. Questerre also constructed a central oil battery and gas compressor facility in the area to address capacity constraints. In January 2007, Questerre received regulatory approval to commence production from its gas pool in Vulcan. Development of its oil pool was expected to commence in late 2008 subject to receipt of regulatory approval.

In February 2007, Questerre and Gastem announced they had entered into a letter of intent for the Yamaska permits, covering 113,000 acres pursuant to the letter of intent, Gastem would commit to spend a minimum of $3 million and a maximum of $13 million on the Yamaska permits. Gastem would earn the 50% working interest currently held by Questerre in these permits subject to a 7.5% convertible gross overriding royalty ("**GORR**") payable to Questerre. The GORR is convertible into a 20% working interest. Gastem had the option to work with additional partners to fulfill its spending commitments under the letter of intent. Questerre also secured an 80% interest in an exploration license covering approximately 53,000 acres adjacent to the St. Jean block.

In March 2007, Questerre and Transeuro agreed to amend their existing farmin and operating agreement (the "**Agreement**") as follows:

- Transeuro would be recognized as the participating party and Ampac was released from its obligations under the Agreement;
- The requirement for a fourth re-entry, one of the wells in the Initial Work Program, was dropped from the earning requirements;
- Transeuro will no longer be committed to drilling a Nahanni well, the second option well, at its sole cost and risk. Instead, Transeuro will earn a 50% interest in the entire Field and all infrastructure upon payment of $10 million to Questerre by April 2007; and
- The partners committed to spud a joint Nahanni well by summer 2007.

In March 2007, Questerre acquired an interest in Transeuro through participation in a private placement. The Corporation subscribed for three million units at $0.61 per unit for gross subscription proceeds of $1.83 million. Each unit consists of one common share of Transeuro and one common share purchase warrant entitling the holder to acquire one Transeuro share at $0.61 until December 31, 2007.

Late in the first quarter of 2007, Questerre doubled its land holdings in the Beaver River area to over 23,000 acres including the exploration rights to all horizons in acreage surrounding the Field. It also acquired the rights to additional horizons at the Field. The majority of these lands were validated with the Corporation's work program in 2007.

In July 2007, Questerre and Transeuro spud the A-8 well at the Field. The well reached total depth of 4112m at year-end 2007.

During the summer of 2007, Gastem spud two wells, St. Francois du Lac No. 1 and St. Louis de Richelieu No. 1 on the Yamaska acreage. Gastem's farm-in partner, Forest Oil Corporation ("**Forest**") subsequently elected to stimulate and test these two wells. In June 2007, Talisman elected to acquire a 2-D seismic survey over a portion of Questerre's acreage to follow-up the results from the Gentilly #1 well. The acquisition program was completed in early 2008.

In November 2007, Questerre acquired Magnus, a public exploration and production company with land and production focused in the Antler area of southeast Saskatchewan. Total consideration was 7,840,804 Common Shares at a deemed price of $0.94 per Common Share and the assumption of a working capital deficit of $13.37 million. Questerre subsequently satisfied Magnus' secured debt of $17.4 million through a cash payment of $15.4 million and the issuance of 2,250,000 Common Shares. Magnus shareholders received 0.015316 Questerre Common Shares for each Magnus Class A share held. Each Magnus Class B share was exchanged for 10 Magnus Class A shares prior to the exchange of Magnus Class A shares for Common Shares. Upon closing, Magnus became a wholly-owned subsidiary of Questerre.

In December 2007, Questerre entered into a farmin agreement with a major Canadian exploration and production company covering 54 square miles in the Greater Sierra region of British Columbia. Questerre's commitments under this agreement were to fund the drilling and completion of two wells and a 46-square mile 3-D seismic survey to earn a 50% interest in this acreage. Questerre fulfilled these obligations prior to the end of the first quarter of 2008 and earned its interest in this acreage.

In December 2007, the Corporation completed two private placements through the issuance of 3,500,000 Common Shares, on a flow-through basis, for gross proceeds of $3 million as follows:

2,500,000 Common Shares at $0.80 per Common Share and 1,000,000 Common Shares at $1.00 per Common Share.

Questerre's capital expenditures in 2008 targeted the Antler area of southeast Saskatchewan with the drilling of 15 and stage fracturing 17 horizontal wells. Questerre also participated in the drilling and completion of a horizontal well into the Manville I Pool in Vulcan during the year.

A significant shale gas discovery reported by Forest on the Yamaska permits in April 2008 subsequently led to multi-well appraisal programs by Talisman and Forest. Forest drilled and stimulated three horizontal wells, with the majority on the Yamaska permits. Upon the completion of this initial program in the fourth quarter by Forest, Questerre converted its 7.5% GORR into a 20% working interest on the Yamaska permits.

Talisman's program included a commitment to drill the remaining three farm-in wells under the Talisman Farmout and re-complete the first well, Gentilly No. 1. Two of the three wells, La Visitation No. 1 and St. David No. 1, were drilled prior to year-end 2008 with the third well, St. Edouard No. 1 completed in early 2009.

In the second quarter of 2008, Questerre completed a $75.79 million equity offering at $4.70 per Common Share. The offering consisted of the issuance of 7,500,000 Common Shares on a private placement basis in Norway and 8,625,000 Common Shares through a short-form prospectus in Canada.

Effective April 30, 2008, Questerre acquired all the outstanding common shares and preferred shares of Terrenex Ltd. ("**Terrenex**"), a public investment company that was the successor entity to TAC. Terrenex was a corporation with common directors and officers. Terrenex's principal assets were a working interest in sixteen exploration licenses and a seismic database in the Lowlands and 10,698,785 Questerre Common Shares. On February 22, 2008, the Corporation entered into an agreement to acquire Terrenex for consideration of 15,892,785 Common Shares and $0.50 million in cash. On April 27, 2008, the agreement was amended and the share consideration increased to 18,910,403 Common Shares. On April 28, 2008, the transaction received the requisite Terrenex shareholder and Court approval. Net of the 10,698,785 Questerre Common Shares held by Terrenex at the time of acquisition, a total of 8,211,618 Common Shares were issued for the acquisition. Terrenex was subsequently amalgamated with Questerre effective September 1, 2009 and the 10,698,785 Common Shares held by Terrenex were cancelled effective September 30, 2009.

On June 18, 2008, Magnus and its wholly owned subsidiary Magnus One Energy Corp. (collectively the "Magnus Entities") applied for protection under the Bankruptcy and Insolvency Act. Magnus is a wholly owned subsidiary of Questerre. At meetings of the secured and unsecured creditors of the Magnus Entities held on September 30, 2008, the creditors approved a proposal to settle amounts outstanding. Court approval of this proposal was obtained on April 2, 2009. Subject to the resolution of contingent creditor claims, implementation of the proposal is expected to be completed in the first half of 2010.

In the third quarter of 2009, Talisman finalized the drilling and completion of St. Edouard No. 1, the fourth and final well in the program. This marked the end of the earn-in program by Talisman. Talisman currently holds a 75% working interest in approximately 720,000 joint acres. Questerre holds an approximate 25% working interest in this acreage and also retains a 4¼% gross overriding royalty on production from Talisman.

During 2009, the Company primarily focused on the continued appraisal of the Utica shale in Quebec. Vertical wells drilled by Talisman were fracture stimulated and subsequently flow-tested. Based on the results, the partners elected to begin a pilot horizontal program to assess commerciality. Two wells in this program, St. Edouard No. 1A and Gentilly No. 2, were spud in the second half of the year.

Significant Acquisitions

Questerre has not completed any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

Recent Developments

On February 23, 2010, Questerre announced test results from the St. Edouard No. 1A horizontal well in the St. Lawrence Lowlands, Québec. The horizontal well was successfully completed with 8 stage fracture stimulations. Clean up and flow back commenced January 29, 2010. Initial rates were over 12 MMcf/d. During the test, the well flowed natural gas at an average rate of over 6 MMcf/d. The well is still flowing on an extended production test. On February 23, 2010, the rate was approximately 5 MMcf/d at a flowing tubing pressure of 4412 kilopascals (640 pounds per square inch) with a choke size of 5/8 inch. During completion, microseismic data was gathered using the St. Edouard No. 1 vertical well as a monitoring well. Preliminary analysis indicates that the fracs were successful in stimulating sufficient rock volume in the entire Utica sequence.

On March 1, 2010, Questerre reported on its year-end reserves and updated resource assessment of the Utica shale gas discovery in Québec. Based on the independent assessment titled "Assessment of Unrisked Prospective Gas Resources to the Questerre Energy Corporation Interest in the Utica Shale for Certain Acreage Located in St. Lawrence Lowlands of Québec, Canada" completed by Netherland, Sewell & Associates, Inc. with an effective date of November 1, 2009, the best estimate of unrisked prospective recoverable natural gas resources on Questerre's acreage is 17.99 Tcf (3 billion boe), with a high estimate of 56.93 Tcf (9.49 billion boe) and a low estimate of 5.50 Tcf (917 million boe). This equates to 4.36 Tcf (726 million boe) net to Questerre using a 10% recovery factor and does not include the benefit of its gross overriding royalty. The effective range of recovery factors in the report is from a low of 5% to a high of 23%. The 23% recovery factor resulted in an unrisked prospective recoverable resource assignment of 13.78 Tcf (2.30 billion boe) net to Questerre. The 5% recovery factor resulted in an unrisked prospective recoverable resource assignment of 1.33 Tcf (222 million boe) net to Questerre. Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. There is no certainty that any portion of the prospective resources in Québec will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

In March 2010, Questerre closed an equity issuance of 30,000,000 Common Shares at a price of $4.30 per share for gross proceeds of approximately $129 million. This was comprised of 19,972,000 Common Shares on a private placement basis in Norway and 10,028,000 Common Shares by way of a short form prospectus offering in Canada.

Environmental Matters

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. As at December 31, 2009, Questerre recorded an obligation on its balance sheet of $4.76 million for asset retirement. The Corporation maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. The Corporation also has operational and emergency response procedures and safety and environmental programs in place to reduce potential loss exposure.

Employees

At December 31, 2009, Questerre's work force consisted of 19 employees including two field operators at Beaver River. Questerre also has two part-time consultants at the head office and two contract operators – one in Alberta and one in Saskatchewan.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Questerre competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Questerre's competitors include resource companies which have greater financial resources, staff and facilities than those of Questerre. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Questerre believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development. See "Risk Factors".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Petroleum and Natural Gas Reserves

McDaniel & Associates Consultants Ltd. ("**McDaniel**"), independent petroleum engineers of Calgary, Alberta prepared an Evaluation of Oil & Gas Reserves dated February 5, 2010 (the "**McDaniel Report**") which evaluation is effective December 31, 2009. **The McDaniel Report is in respect of Questerre's conventional oil and gas properties and excludes its assets in the Lowlands to which no reserves are currently assigned.** In preparing its report, McDaniel obtained basic information from Questerre, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the McDaniel Report is based, was obtained from public records, other operators and from McDaniel's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by McDaniel as represented.

The following tables set forth certain information relating to the oil and natural gas reserves of the Corporation's properties and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2009, which numbers may vary slightly from those presented in the McDaniel Report due to rounding. Also due to rounding, certain columns may not add exactly. The information set forth below is derived from the McDaniel Report which report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in National Instrument 51-101 - Standards of Disclosure For Oil and Gas Activities ("**NI 51-101**"). **All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The estimated future net cash flow from the production of disclosed oil and gas reserves does not represent the fair market value of the Corporation's reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of**

crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2

Appendix B: Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3

Definitions used for reserve categories in the McDaniel Report are attached as Appendix C hereto.

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2009

FORECAST PRICES AND COSTS

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved						
Developed Producing	542.0	495.4	2,369.4	1,779.8	13.8	7.4
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	183.0	171.3	15.4	12.0	0.1	0.1
Total Proved	725.0	666.7	2,384.8	1,791.8	13.9	7.5
Probable	658.3	610.4	1,087.3	823.3	5.7	3.5
Total Proved Plus Probable	1,383.3	1,277.1	3,472.1	2,615.1	19.6	11.0

SUMMARY NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2009

FORECAST PRICES AND COSTS

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR) 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved					
Developed Producing	36,789.8	31,146.8	27,020.8	23,905.9	21,487.8
Developed Non-Producing	-	-	-	-	-
Undeveloped	6,359.3	4,847.5	3,712.2	2,842.3	2,163.0
Total Proved	43,149.1	35,994.3	30,733.0	26,748.2	26,650.8
Probable	42,165.0	30,009.8	22,318.3	17,149.6	13,500.2
Total Proved Plus Probable	85,314.1	66,004.1	53,051.3	43,897.8	37,151.0

SUMMARY NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2009

FORECAST PRICES AND COSTS

RESERVES CATEGORY	AFTER INCOME TAXES DISCOUNTED AT (%/YEAR) 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved					
Developed Producing	36,789.8	31,146.8	27,020.8	23,905.9	21,487.8
Developed Non-Producing	-	-	-	-	-
Undeveloped	6,359.3	4,847.5	3,712.2	2,842.3	2,163.0
Total Proved	43,149.1	35,994.3	30,733.0	26,748.2	23,650.8
Probable	38,735.5	27,913.2	20,994.7	16,289.8	12,927.6
Total Proved Plus Probable	81,884.6	63,907.5	51,727.7	43,038.0	36,578.4

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2009
FORECAST PRICES AND COSTS

(M$)

RESERVES CATEGORY	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
Proved Reserves	85,845.1	10,303.9	24,273.8	6,154.7	1,963.6	43,149.1	-	43,149.1
Proved Plus Probable Reserves	162,061.7	18,048.6	42,663.4	13,836.3	2,199.3	85,314.1	3,429.5	81,884.6

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2009

FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE (discounted at 10%/year) ($/bbl) ($/Mcf)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	26,711.7	39.62
	Natural Gas (including by-products but excluding solution gas from oil wells)	4,021.3	2.24
	Total	**30,733.0**	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	47,290.2	36.71
	Natural Gas (including by-products but excluding solution gas from oil wells)	5,761.1	2.20
	Total	**53,051.3**	

MCDANIEL PRICING ASSUMPTIONS

Forecast Prices and Costs Employed by McDaniel - January 1, 2010

McDaniel employed the following pricing, exchange rate and inflation rate assumptions in estimating Questerre's reserves data using forecast prices and costs as of January 1, 2010.

McDaniel & Associates Consultants Ltd.
Summary of Price Forecasts
January 1, 2010

Year	WTI Crude Oil $US/bbl	Brent Crude Oil $US/bbl	Edmonton Light Crude Oil $C/bbl	Alberta Bow River Hardisty Crude Oil $C/bbl	Alberta Heavy Crude Oil $C/bbl	Sask Cromer Medium Crude Oil $C/bbl	Edmonton Cond. & Natural Gasolines $/bbl	Edmonton Propane $/bbl	Edmonton Butanes $/bbl	Edmonton NGL Mix $/bbl	Inflation %	US/CAN Exchange Rate $US/$CAN
	(1)	(2)	(3)	(4)	(5)	(6)				(7)		
Forecast												
2010	80.00	78.50	83.20	72.30	68.10	76.50	85.20	46.40	64.00	60.30	2.0	0.950
2011	83.60	82.10	87.00	73.80	67.60	79.10	89.00	49.50	66.90	63.50	2.0	0.950
2012	87.40	85.80	91.00	74.40	68.00	81.80	93.10	52.00	70.00	66.50	2.0	0.950
2013	91.30	89.70	95.00	75.80	68.10	85.40	97.10	54.30	73.10	69.40	2.0	0.950
2014	95.30	93.70	99.20	79.20	71.10	89.20	101.40	56.70	76.30	72.50	2.0	0.950
2015	99.40	97.70	103.50	82.60	74.20	93.10	105.70	59.20	79.60	75.60	2.0	0.950
2016	101.40	99.70	105.60	84.30	75.70	94.90	107.90	60.50	81.20	77.20	2.0	0.950
2017	103.40	101.70	107.70	85.90	77.20	96.80	110.00	61.70	82.80	78.70	2.0	0.950
2018	105.40	103.60	109.80	87.60	78.70	98.70	112.10	62.90	84.50	80.30	2.0	0.950
2019	107.60	105.80	112.10	89.40	80.40	100.70	114.50	64.20	86.20	82.00	2.0	0.950
2020	109.70	107.90	114.30	91.20	81.90	102.70	116.70	65.50	87.90	83.60	2.0	0.950
2021	111.90	110.00	116.50	93.00	83.60	104.80	119.00	66.80	89.60	85.20	2.0	0.950
2022	114.10	112.20	118.80	94.80	85.20	106.80	121.30	68.20	91.40	86.90	2.0	0.950
2023	116.40	114.50	121.20	96.70	86.90	109.00	123.80	69.60	93.20	88.70	2.0	0.950
2024	118.80	116.80	123.70	98.70	88.70	111.20	126.30	71.00	95.20	90.50	2.0	0.950
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.950

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur
(2) North Sea Brent Blend 37 degrees API/1.0% sulphur
(3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(4) Bow River at Hardisty Alberta (Heavy stream)
(5) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality)
(6) Midale Cromer crude oil 29 degrees API, 2.0% sulphur
(7) NGL Mix based on 45 percent propane, 35 percent butane and 20 percent natural gasolines.

McDaniel & Associates Consultants Ltd.
Summary of Gas Price Forecasts
January 1, 2010

Year	U.S Henry Hub Gas Price $US/MMBtu	Alberta AECO Spot Price $C/MMBtu	Alberta Average Plantgate $C/MMBtu	Alberta Aggregator Plantgate $C/MMBtu	Alberta Spot Sales Plantgate $C/MMBtu	Sask. Prov. Gas Plantgate $C/MMBtu	Sask. Spot Sales Plantgate $C/MMBtu	British Columbia Average Plantgate $C/MMBtu
			(1)					
Forecast								
2010	6.05	6.05	5.85	5.85	5.85	5.95	5.95	5.85
2011	6.90	6.75	6.55	6.55	6.55	6.65	6.65	6.55
2012	7.30	7.15	6.95	6.95	6.95	7.05	7.05	6.95
2013	7.70	7.45	7.25	7.25	7.25	7.35	7.35	7.25
2014	8.15	7.80	7.60	7.60	7.60	7.70	7.70	7.60
2015	8.50	8.15	7.95	7.95	7.95	8.05	8.05	7.95
2016	8.75	8.40	8.15	8.15	8.15	8.25	8.25	8.15
2017	8.90	8.55	8.30	8.30	8.30	8.40	8.40	8.30
2018	9.10	8.70	8.45	8.45	8.45	8.55	8.55	8.45
2019	9.30	8.90	8.65	8.65	8.65	8.75	8.75	8.65
2020	9.45	9.05	8.80	8.80	8.80	8.90	8.90	8.80
2021	9.65	9.25	9.00	9.00	9.00	9.10	9.10	9.00
2022	9.85	9.45	9.20	9.20	9.20	9.35	9.35	9.20
2023	10.05	9.65	9.40	9.40	9.40	9.55	9.55	9.40
2024	10.25	9.85	9.60	9.60	9.60	9.75	9.75	9.60
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

Notes:
(1) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the crown royalty calculations.

Questerre's weighted average realized sales prices for the year ended December 31, 2009 were $63.88/bbl for crude oil and NGLs and $4.34/Mcf for natural gas.

RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE
Gross Reserves Reconciliation

The following table sets forth a reconciliation of Questerre's total gross proved, probable and proved plus probable reserves as at December 31, 2009 against such reserves as at December 31, 2008 based on forecast price and cost assumptions.

	LIGHT AND MEDIUM OIL			ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2008	941.5	529.6	1,471.1	3,157.7	5,342.8	8,500.5	14.0	15.3	29.3
Extensions & Improved Recovery	23.0	36.2	59.2	15.3	8.2	23.5	-	0.3	0.3
Technical Revisions	(105.0)	92.8	(12.2)	219.0	(87.1)	131.9	4.8	(0.8)	4.0
Dispositions	-	-	-	-	(517.5)	(517.5)	-	(5.6)	(5.6)
Economic Factors	-	-	-	(77.6)	(3,658.3)	(3,735.9)	-	(3.5)	(3.5)
Production	(134.5)	(0.3)	(134.8)	(929.6)	(0.8)	(930.4)	(4.9)	-	(4.9)
December 31, 2009	725.0	658.3	1,383.3	2,384.8	1,087.3	3,472.1	13.9	5.7	19.6

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

The following discussion generally describes the basis on which Questerre attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

Undeveloped Reserves

The following tables set forth the volumes of proved and probable undeveloped reserves that were first attributed in each of Questerre's three most recent financial years and, before that time, in the aggregate. It also discloses the amount booked at the end of each period.

Proved Undeveloped Reserves

Year	LIGHT AND MEDIUM OIL(1) (Mbbl)		NATURAL GAS LIQUIDS (Mbbl)		NATURAL GAS(2) (MMcf)	
	First Attributed(3)	Booked	First Attributed(3)	Booked	First Attributed(3)	Booked
Aggregate prior to 2007	-	-	-	-	-	-
2007	140.0	140.0	-	-	-	-
2008	-	229.8	-	-	-	-
2009	-	183.0	-	0.1	-	15.4

Probable Undeveloped Reserves

Year	LIGHT AND MEDIUM OIL(1) (Mbbl)		NATURAL GAS LIQUIDS (Mbbl)		NATURAL GAS(2) (MMcf)	
	First Attributed(3)	Booked	First Attributed(3)	Booked	First Attributed(3)	Booked
Aggregate prior to 2007	-	-	-	-	1,001.6	1,001.6
2007	225.0	270.0	7.0	7.3	552.0	1,396.2
2008	-	195.6	-	9.7	-	3,607.7
2009	-	366.2	-	0.1	-	8.1

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas from oil wells.
(3) First attributed only includes proved and probable undeveloped reserves assigned to acquisitions and discoveries.

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year, wells further away from Questerre gathering systems or infill drilling locations. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production.

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Questerre's development plans. Normally, the Corporation plans to develop its proved and/or probable undeveloped reserves within two years.

A number of factors could result in delayed or cancelled development plans. Such factors may include changing economic conditions due to oil and natural gas prices, operating and capital expenditure fluctuations. Changing technical conditions resulting in production anomalies such as premature water break through or higher than anticipated production declines may result in a delay or cancellation of development plans. In wells that have encountered multiple zones, a prospective zone completion may be delayed until the initial completion is no longer economic. Larger development programs may need to be spread out over several years to optimize capital allocation and facility utilization. Surface access issues associated with landowners, weather conditions or regulatory approvals could also influence development plans.

The McDaniel Report attributes 183.0 Mbbl of oil reserves as “proved undeveloped”. This relates to one infill drilling location in Vulcan and several infill and step-out locations in Antler. The Company plans to drill the location in Vulcan this year pending regulatory approval and, subject to equipment availability and results, Questerre has scheduled a drilling program at Antler targeting the infill and step-out locations that have been assigned proved undeveloped reserves.

Undeveloped Reserves - Probable Undeveloped Reserves

In most instances, the probable undeveloped reserves assigned to the Corporation are those reserves associated with the proven undeveloped reserves using a more optimistic decline analysis. Additional production information will, in all probability, result in the reclassification of these reserves into proven developed producing reserves. The McDaniel Report attributes 366.2 Mbbl of oil reserves as “probable undeveloped”. On top of the proposed drilling discussed in the proved undeveloped section above there are also probable undeveloped reserves included with respect to a proposed waterflood project in the Antler area. The anticipation for this waterflood is for it to be completed over the next few years.

At December 31, 2009, the Company’s natural gas probable undeveloped reserves declined substantially from the prior year. These reserves as at December 31, 2008 were assigned to drilling locations in Greater Sierra and Beaver River. Due to significantly weaker than expected natural gas prices drilling of these locations has been postponed pending a recovery in commodity prices.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Questerre’s reserves are evaluated by McDaniel, an independent petroleum engineering firm.

Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. Questerre’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.

Future Development Costs

The following table outlines the capital costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs) to those properties evaluated in the McDaniel Report.

	Forecast Prices and Costs	
Year ($ thousand)	Proved Reserves	Proved Plus Probable Reserves
2010	3,735.8	9,804.8
2011	2,418.9	4,031.6
2012	-	-
2013	-	-
2014	-	-
Thereafter	-	-
Total Undiscounted	6,154.7	13,836.4
Total Discounted at 10%	5,659.0	12,843.0

Questerre estimates that its internally generated cash flow will be sufficient to fund the future development costs disclosed above. Questerre typically has available four sources of funding to finance its capital expenditure program: current cash balances, internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms. Any acquisition opportunities would likely be financed through debt or equity financings.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

Questerre has five core areas where it conducts the majority of its activity: St. Lawrence Lowlands - Québec, Greater Sierra - British Columbia, Beaver River - British Columbia, Antler – Saskatchewan and Vulcan – Alberta.

St. Lawrence Lowlands, Québec

The St. Lawrence Lowlands (the "**Lowlands**") are situated in Québec south of the St. Lawrence River between Montréal and Québec City. The exploration potential of the Lowlands is complemented by proximity to one of the largest natural gas markets in North America, a well-established distribution network and favourable fiscal terms.

The area is prospective for natural gas in several horizons with the primary target of the Ordovician Utica shale at a depth of 400 to 2200 metres with secondary targets including the shallower Lorraine shale and the deeper Trenton Black-River carbonate ("**TBR**") at approximately 1800 to 2300 metres.

During the year, Questerre finalized a joint vertical test well program with its partner, Talisman. Targeting the Utica, this included the drilling and completion of St. Edouard No. 1 and the completion and testing of two wells drilled in 2008 – La Visitation No. 1 and St. David No. 1.

The stabilized initial rates from these wells ranged between 300 Mcf/d and 700 Mcf/d. Production logging indicates the majority of the flow is attributable to an interval within the middle Utica. These rates are in line with the middle Utica flow rates of over 800 Mcf/d from

Gentilly No. 1, the first well in the program, and 900 Mcf/d from Leclercville No. 1, drilled offsetting the joint acreage.

Consistent results over a large geographic area provided the momentum to begin a pilot horizontal well program for the middle Utica to assess commerciality. Two horizontal wells were spud in the second half of 2009. The wells were situated next to existing verticals for micro-seismic monitoring of frac effectiveness. The first, St. Edouard No. 1A, was successfully drilled and the horizontal leg was completed with eight stage fracture stimulations in early 2010. Initial flow rates were over 12 MMcf/d with an average stabilized rate of approximately 6 MMcf/d. The well is currently on a long-term test. Drilling operations on the second horizontal well, Gentilly No. 2, were completed in early 2010 and the well will be fracture stimulated later this year.

Subject to results and partner participation, Questerre anticipates this pilot program could be expanded to include several other horizontal wells, 3-D seismic surveys and a pipeline tie-in to the local distribution system.

The evaluation of the Utica included the testing of other prospective intervals within this horizon. Targeting the upper Utica, Questerre's partner, Forest, completed the testing of two prototype horizontal wells on the Yamaska permits earlier in the year. Stabilized rates of between 100 Mcf/d and 800 Mcf/d were achieved with initial rates of up to 4 MMcf/d. These results reflect in part the slower than expected cleanup of the frac fluid. The companies have developed alternative completion programs to address this issue and Questerre anticipates Forest will conduct this additional work in the future. In the interim, Forest plans to acquire 2-D seismic this year in advance of further drilling on these permits.

Questerre completed the St. Jean sur Richelieu No. 1 well to evaluate the shallower Utica shale south of the main fairway. Fracture stimulation yielded sustained gas flows at limited rates with frac efficiency less than expected. Additional work is ongoing to determine if gas fracturing can improve frac effectiveness and commerciality. The Company believes this acreage could be developed with vertical wells and multiple small fracs similar to other shallow tight gas projects.

In addition to the Utica, Questerre and Talisman also tested two other zones of interest in the Lowlands.

Successful fracs were completed in the shallower Lorraine shale in La Visitation No. 1 and Gentilly No. 1. Sustained gas flows resulted at rates of approximately 100 Mcf/d. Results were affected by flow-back of the proppant and frac fluid. Further work, including fluid compatibility studies, is necessary to improve the effectiveness of the stimulation.

Testing of the TBR in the St. Edouard No. 1 resulted in a final gas rate of approximately 2 MMcf/d over a three day test with no formation water. Pressure data indicates that the estimated reserves would be insufficient to support tie-in costs and the interval was suspended. With the focus on the Utica, further exploration for this zone has been deferred in the near term.

<u>British Columbia</u>

Greater Sierra

The Greater Sierra region lies approximately 100 km east of Fort Nelson, British Columbia. The primary zone of interest is the Devonian Jean Marie at a depth of approximately 1400 metres. The region is also prospective for shallower zones including the Mississippian Debolt as well as the deeper Devonian Keg River, Slave Point, Pine Point formations as well as the Horn River shale.

Through a farm-in agreement with EnCana Corporation ("**EnCana**"), Questerre established a new core area in the Greater Sierra region of northeast British Columbia early in 2008. EnCana's existing gathering system throughout this acreage provides access to the Spectra Energy pipeline and processing plant at Fort Nelson.

A planned Jean Marie drilling program with EnCana was deferred in 2009 with lower than expected natural gas prices.

Questerre acquired an additional 14,680 (11,680 net) acres south of its acreage with EnCana at a Crown land sale in 2009. The land is prospective for the primary Jean Marie formation in addition to the deeper Horn River shales and the Pine Point carbonates. Locations have been identified to test the deeper carbonate anomalies and assess the shale intervals.

Questerre plans to work with an industry partner to pursue these locations and develop this acreage.

Beaver River Field

The Field is located approximately 160 km northwest of Fort Nelson, on the border of British Columbia and the Yukon. Production from the field benefits from extensive infrastructure including processing facilities, a local gathering system and a tie-in to the Spectra Energy pipeline. Questerre currently holds a 50% interest in over 23,000 acres in this area.

There are multiple zones of interest including three interbedded shale, siltstone and sandstone intervals known as the Mattson, Besa River and Golata at a depth of 1300 metres – 3300 metres and the Nahanni, a hydrothermally dolomitized carbonate sequence at a depth of approximately 3300 metres.

Testing of the shale at the Field in 2009 was set back with extended production shut-ins due to low natural gas prices, plant turnarounds, unusually cold weather and operational challenges.

The A-5 well, recompleted in late 2008, targeted a brittle dolomite interval above an organic rich shale sequence. The well tested at an initial gross rate of 10 MMcf/d and was on production intermittently during the year most recently at the beginning of the fourth quarter with initial gross rates of over 2 MMcf/d. Results to date indicate minimal contribution from the deeper shale and additional work will be required.

Questerre and its partner continue to explore joint venture opportunities to further assess the shale horizons at Beaver River.

<u>Antler, Saskatchewan</u>

The Antler area is approximately 200 km from Regina in southeast Saskatchewan. The primary target is light oil from the Bakken/Torquay formation, a dolomitic siltstone shale sequence at a depth of between 1050 metres and 1150 metres.

Following a multi-well horizontal pilot program in 2008, a detailed review of the existing wells and drilling and completion practices was conducted in 2009 to improve recovery of the oil in place. Modified completion techniques were tested to confine the fracture stimulation within the target Bakken/Torquay interval and minimize water production from adjacent intervals. The Company also evaluated tubing conveyed fracture stimulation as an alternative to the Packers Plus system. Preliminary results are positive and Questerre plans to implement these in its current drilling program.

Vulcan, Alberta

The Vulcan area in Southern Alberta is prospective for natural gas and oil in multiple horizons with the Mannville Sunburst formation as the main zone of interest at a depth of approximately 1900 metres. Questerre participated in the discovery of two adjacent Mannville pools in Vulcan in 2005 and 2006 and holds a 50% interest in both pools.

Delayed regulatory approval for a minor compressor upgrade in Vulcan hindered production optimization from the Mannville I Pool. This in turn has set back plans for a proposed infill well into this oil pool. Subject to the timing of approvals, Questerre anticipates this well could be drilled towards the end of 2010.

In the current fiscal and regulatory environment, Questerre does not anticipate conducting any other drilling in Alberta in 2010.

Wells

As at December 31, 2009, the Corporation had an interest in 67 gross (28.5 net) producing and 70 gross (36.0 net) non-producing oil and natural gas wells as follows.

	PRODUCING				NON-PRODUCING			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross[(1)]	Net[(2)]	Gross	Net	Gross	Net	Gross	Net
Wells								
Alberta	8.0	3.7	25.0	6.8	6.0	3.4	28.0	13.9
British Columbia	-	-	6.0	3.0	-	-	7.0	3.5
Saskatchewan	28.0	15.0	-	-	19.0	12.5	-	-
Québec	-	-	-	-	-	-	10.0	2.7
TOTAL	36.0	18.7	31.0	9.8	25.0	15.9	45.0	20.1

Notes:

(1) "Gross" wells means the number of wells in which Questerre has a working interest or a royalty interest that may be convertible to a working interest.

(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by Questerre's percentage working interest therein.

Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by the Corporation as at December 31, 2009 and the net area of unproved property for which the Corporation expects its rights to explore, develop and exploit to expire during the next year.

UNPROVED PROPERTIES (acres)

LOCATION	Gross [(1)]	Net [(2)]	Net Area to Expire by December 31, 2010
Alberta	8,320	4,585	-
British Columbia	78,235	43,357	-
Saskatchewan	30,374	20,023	6,601
Québec	1,011,935	304,361	-
TOTAL	1,128,864	372,326	6,601

Notes:

(1) "Gross Acres" are the total acres in which Questerre has or had an interest.

(2) "Net Acres" is the aggregate of the total acres in which Questerre has or had an interest multiplied by Questerre's working interest percentage held therein.

There are no costs or work commitments associated with Questerre's non-producing properties except for ongoing Crown and freehold lease commitments.

Forward Contracts

Questerre may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. Questerre currently has no outstanding derivative or hedging contracts.

Additional Information Concerning Abandonment and Reclamation Costs

Questerre estimates abandonment and reclamation costs for surface leases, wells and facilities based on its previous experience, current regulations, costs, technology and industry standards. Such costs are included in the McDaniel Report as deductions in arriving at future net revenue. The expected total abandonment costs for 64.5 net wells (including producing, non-producing and service wells) net of estimated salvage values are summarized below without discount and using a discount rate of 10%:

	Forecast (M$) Pricing			
	Proved NPV 0%	Proved NPV 10%	Proved plus Probable NPV 0%	Proved plus Probable NPV 10%
Total abandonment and reclamation cost provision	1,964	910	2,199	833
Portion forecast to be paid during the next three years	374	305	343	278

We have estimated the net present value of our total asset retirement obligations to be $4.76 million as at December 31, 2009 based on a total future liability of $9.58 million. The future net revenues disclosed in this Annual Information Form based on the McDaniel Report do not contain an allowance for abandonment and reclamation costs for batteries and salvage values are deducted, which are not allowed under Canadian GAAP.

Income Tax Horizon

The income tax deducted in the calculation of future net revenue assumes a blow-down scenario whereby Questerre produces out its existing reserves and does not reinvest any capital. Under this scenario, and given Questerre's existing tax pools at December 31, 2009, Questerre does not expect to incur current income taxes in the year ending December 31, 2010.

Costs Incurred

The following table summarizes Questerre's property acquisition costs, development costs and exploration costs incurred during the financial year ended December 31, 2009.

Nature of cost	Amount ($)
Property Acquisition Costs:	
Proved Properties (1)	-
Unproved Properties	-
Development Costs (2)	4,506,493
Exploration Costs (3)	7,483,048
Total	11,989,541

Notes:
(1) Acquisitions are net of disposition of properties.
(2) Development and facilities expenditures.
(3) Cost of land acquired, geological and geophysical capital expenditures and drilling costs for 2009 exploration wells drilled.

Exploration and Development Activities

The following table summarizes the results of exploration and development activities during the financial year ended December 31, 2009.

	Gross	Net
Development Wells		
Gas	-	-
Oil	1.00	1.00
Service	-	-
Dry	-	-
Exploratory Wells		
Gas	3.00	0.71
Oil	-	-
Service	-	-
Dry	-	-
Total Wells	4.00	1.71

Our most important current exploration and development activities include the following:

- Exploration for natural gas with the continued assessment of the Utica shale gas discovery in the St. Lawrence Lowlands, Quebec.
- Development drilling for light oil in the Antler, Southeast Saskatchewan area.

Production Estimates

The following discloses the estimated average daily sales of products of Questerre through fiscal 2010 by product type associated with the first year of the gross proved reserves and gross probable reserves estimates reported in the McDaniel Report, effective December 31, 2009.

	Light and Medium Crude Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Combined BOE (boe/d)
Corporation				
Proved				
Developed producing	303.7	2,288.9	10.3	695.6
Developed non-producing	-	-	-	-
Undeveloped	65.3	5.1	-	66.2
Total Proved	369.0	2,294.0	10.3	761.8
Probable	105.5	128.4	0.9	127.6
Total proved plus probable	474.5	2,422.4	11.2	889.4

	Light and Medium Crude Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Combined BOE (boe/d)
Vulcan, AB				
Proved				
Developed producing	56.7	912.2	7.3	216.0
Developed non-producing	-	-	-	-
Undeveloped	8.1	5.1	-	9.0
Total Proved	64.8	917.3	7.3	225.0
Probable	5.1	34.9	0.3	11.2
Total proved plus probable	69.9	952.2	7.6	236.2
Other Alberta				
Proved				
Developed producing	1.3	250.9	2.7	45.8
Developed non-producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved	1.3	250.9	2.7	45.8
Probable	-	37.6	0.5	6.8
Total proved plus probable	1.3	288.5	3.2	52.6
Beaver River, BC				
Proved				
Developed producing	-	892.7	-	148.8
Developed non-producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved	-	892.7	-	148.8
Probable	-	50.6	-	8.4
Total proved plus probable	-	943.3	-	157.2
Greater Sierra, BC				
Proved				
Developed producing	-	233.1	0.3	39.2
Developed non-producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved	-	233.1	0.3	39.2
Probable	-	5.3	0.1	0.9
Total proved plus probable	-	238.4	0.4	40.1
Antler, SK				
Proved				
Developed producing	245.8	-	-	245.8
Developed non-producing	-	-	-	-
Undeveloped	57.2	-	-	57.2
Total Proved	303.0	-	-	303.0
Probable	100.3	-	-	100.3
Total proved plus probable	403.3	-	-	403.3

Netback and Production History

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

	Three Months ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
Average Daily Production				
Crude Oil and NGLs (bbl/d)	463	357	352	343
Natural Gas (Mcf/d)	3,514	2,694	1,680	2,499
Total (boe/d)	1,049	806	632	759
Average Net Price Received				
Crude Oil and NGLs ($/bbl)	49.11	63.98	70.72	76.30
Natural Gas ($/Mcf)	5.31	3.64	3.21	4.53
Royalties				
Crude Oil and NGLs ($/bbl)	7.41	7.84	12.28	10.80
Natural Gas ($/Mcf)	0.51	(0.62)	(3.06)	0.62
Operating Expenses				
Crude Oil and NGLs ($/bbl)	9.20	7.00	11.59	12.11
Natural Gas ($/Mcf)	2.68	2.72	3.78	2.74
Netback Received				
Crude Oil and NGLs ($/bbl)	32.50	49.14	46.85	53.39
Natural Gas ($/Mcf)	2.12	1.54	2.49	1.17

Production Volume by Field

The following table discloses for each significant field, and in total, Questerre's average wellhead production volumes for the period ended December 31, 2009 for each product type.

Field	Light and Medium Crude Oil (bbl/d) (1)	Natural Gas (Mcf/d)	BOE (boe/d)	%
Beaver River	-	779	130	16
Greater Sierra	-	238	40	5
Vulcan	99	1,276	312	38
Other Alberta	4	298	53	7
Antler	275	-	275	34
Québec	-	-	-	-
Total	378	2,591	810	100

Notes:
(1) Includes an immaterial amount of NGLs.

RISK FACTORS

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. Oil and natural gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Questerre.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues 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 drilling, completion and operating costs. In addition, drilling hazards 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 close 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.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, including geo-political events, all of which are beyond the control of Questerre. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices will result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the future volume of Questerre’s oil and gas production. Questerre might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Questerre’s future net production revenue, causing a reduction in its oil and gas exploration, development and acquisition activities. In addition, bank borrowings available to Questerre will be in part determined by the borrowing base of Questerre. A sustained material decline in prices from historical average prices could reduce Questerre’s future borrowing base, therefore reducing the bank credit available to Questerre.

In addition to establishing markets for its oil and natural gas, Questerre must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by Questerre will be affected by numerous factors beyond its control. Questerre will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Questerre. The ability of Questerre to market natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. Questerre will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business. Questerre has limited direct experience in the marketing of oil and natural gas.

Fiscal and Royalty Regime

In addition to federal regulation, each province has legislation and regulations which govern land tenure, drilling and construction permits, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced.

The Government of Québec has announced an intention to introduce a new Hydrocarbon Act. The Government has stated its intention is to make Québec's regulatory system competitive with other jurisdictions in North America. There is no draft of this legislation available and there is no assurance that it will in fact be enacted in law or that it will in fact improve the existing system.

The royalty regime in Alberta and any other jurisdictions in which the Corporation's oil and natural gas assets are located, including Québec, may be subject to further review and changes which could adversely impact the Corporation's financial condition and operations. For recent changes see the "Provincial Royalties and Incentives" section in this document.

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 that may be amended from time to time. See "Industry Conditions" at page 40 of this Annual Information Form.

Insurance

Questerre's involvement in the exploration for and development of oil and gas properties may result in Questerre becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Questerre will obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Questerre may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to Questerre. The occurrence of a significant event that Questerre is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Questerre's financial position, results of operations or prospects.

Project Risks

The Corporation will manage and participate in a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Québec is a new area for oil and gas and specialized support services are not locally available. Project cost estimates may not be accurate due to a lack of history of comparable projects. Furthermore, 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: the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of storage capacity; the supply of and demand for oil and natural gas; the availability of alternative fuel sources; the effects of inclement weather; the availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; changes in regulations; the availability and productivity of skilled labour; and 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.

Substantial Capital Requirements; Liquidity

Questerre anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Questerre's future revenues or reserves decline, Questerre 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 flow from 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 Questerre. Moreover, future activities may require Questerre to alter its capitalization significantly. The inability of Questerre to access sufficient capital for its operations could have material adverse effect on Questerre's financial condition, results of operations or prospects.

Competition

Questerre will actively compete for acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than Questerre. Questerre's competitors will include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. Questerre's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities include companies that have greater financial and personnel resources available to them than Questerre.

Questerre's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Title

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, Questerre will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties. However, no absolute assurances can be given that title defects do not exist. If title defects do exist, it is possible that Questerre may lose all or a portion of its right, title and interest in and to the properties to which the title defects relate.

Environmental Risks

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 international conventions and federal, provincial and municipal 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 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 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. No assurance can be given that the application of environmental laws to the business and operations of the Corporation 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.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids resources, reserves and cash flows to be derived therefrom, including many factors beyond the Corporation’s control. In estimating reserves, the chance of commerciality is effectively 100%. For prospective resources, the chance of commerciality will be the product of the chance that a project will result in a discovery of petroleum or natural gas and the chance that an accumulation will be commercially developed. There is no certainty that any portion of the prospective resources in Québec will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

The reserve and associated cash flow information and estimates represent estimates only. In general, 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 historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Corporation’s actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the 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 evaluation.

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. 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.

Actual future net revenue from the Company's assets 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 revenues derived therefrom will vary from the estimates, and such variations could be material.

There are numerous uncertainties inherent in estimating quantities of resources, including many factors beyond the Corporation's control, and no assurance can be given that the indicated level of resources will be realized. In general, estimates of recoverable resources are based upon a number of factors and assumptions made as of the date on which the resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable natural gas and the classification of such resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

No quantitative geological risk assessment was conducted for Questerre's St. Lawrence Lowlands acreage. Geological risking of prospective resources addresses the probability of success for the discovery of petroleum; this risk analysis is conducted independently of probabilistic estimates of petroleum volumes and without regard to the chance of development. Principal risk elements of the petroleum system include: (i) trap and seal characteristics; (2) reservoir presence and quality; (iii) source rock capacity, quality and maturity; and (iv) timing, migration and preservation of petroleum in relation to trap and seal formation. Geological risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators.

Estimates with respect to resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of resources, rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same resources based upon production history will result in variations, which may be material, in the estimated resources.

Questerre's prospective resources described herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources.

Resources estimates may require revision based on actual production experience. Market price fluctuations of natural gas prices may render uneconomic the recovery of the resources.

Reserve Replacement

Questerre's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Questerre successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Questerre may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Questerre's reserves will depend not only on Questerre's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Questerre's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Capital Markets

As a result of global economic conditions, the Corporation may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Although the Corporation's business and asset base have not changed, the lending capacity of many financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash flow from operations, current cash balances, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Corporation's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Based on current funds available and expected cash flow from operations, the Corporation believes it has sufficient funds available to fund its projected capital expenditures. However, if cash flow from operations are lower than expected or capital costs for these projects exceed current estimates, or if the Corporation incurs major unanticipated expense related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties. Any properties not proven before expiry will not be available for production leases.

Operational Dependence

Other companies operate some of the assets in which Questerre has an interest. As a result, Questerre will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Questerre's financial performance. Questerre's return on assets operated by others will therefore depend upon a number of factors that may be outside of Questerre'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.

Key Employees

The success of Questerre will be largely dependent upon the performance of its management and key employees. Questerre does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on Questerre.

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

Permits and Licences

The operations of Questerre may require licences and permits from various governmental authorities. There can be no assurance that Questerre will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its properties.

Additional Funding Requirements

Questerre's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Questerre may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Questerre to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Questerre's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Questerre's ability to expend the necessary capital to replace its reserves or to maintain its production. If Questerre's cash flow from operations and current cash balance is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favorable terms. Any equity financing may result in a change of control of Questerre or holders of its Common Shares suffering further dilution.

Variations in Foreign Exchange Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore effected by the Canadian/United States dollar exchange rate, which will fluctuate over time. Future Canadian/United States exchange rates could accordingly impact the future value of Questerre's reserves as determined by independent evaluators.

Issuance of Debt

From time to time Questerre 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 Questerre's debt levels above industry standards. Neither Questerre's articles nor its bylaws limit the amount of indebtedness that Questerre may incur. The level of Questerre's indebtedness from time to time could impair Questerre's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Questerre's ability to meet its debt service obligations will depend on Questerre's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Questerre. As certain of the indebtedness of Questerre would bear interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Questerre's interest payment obligations and could have a material adverse effect on Questerre's financial condition and results of operations. Further, Questerre's indebtedness would be secured by substantially all of Questerre's assets. In the event of a violation by Questerre of any of its loan covenants or any other default by Questerre on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable and, in certain cases, foreclose on Questerre's assets. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

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. 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 will not benefit from its fluctuating exchange rate.

Availability of Drilling Equipment and Access Restrictions

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 Questerre and may delay exploration and development activities.

Aboriginal Claims

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

Conflicts of Interest

Directors and officers of Questerre may also be directors and officers of other oil and gas companies involved in oil and gas exploration and development, and conflicts of interest may arise between their duties as officers and directors of Questerre and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the ABCA.

Dilution

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

Seasonality

The level of activity in the Canadian 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. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of the Corporation's exploration and development activities, which could in turn have a material adverse impact on the Corporation's business, operations and prospects.

Third Party Credit Risk

The Corporation is, or 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.

Dividends are Discretionary

The Corporation is not obligated to pay dividends on the Common Shares. The payment of dividends is at the sole discretion of the Corporation's board of directors and it may decide to eliminate or reduce any dividends paid on the Common Shares, or retain cash otherwise available for dividends for investment in our business. In addition, certain of its agreements may restrict its ability to pay dividends, and thus the Corporation's ability to pay dividends on its Common Shares will depend on, among other things, the Corporation's level of indebtedness at the time of the proposed dividend and whether it is in compliance with such agreements. Any reduction or elimination of dividends could cause the market price of the Common Shares to decline and could further cause the Common Shares to become less liquid, which may result in losses to shareholders.

Future Sales of Common Shares

The Corporation may issue additional Common Shares in the future, which may dilute a shareholder's holdings in the Corporation. The Corporation's articles permit the issuance of an unlimited number of Common Shares, Class B Shares (as defined herein) and Preferred Shares (as defined herein), and shareholders will have no pre-emptive rights in connection with such further issuances. The directors of the Corporation have the discretion to determine the provisions attaching to any series of Preferred Shares and the price and the terms of issue of further issuances of Common Shares or Class B Shares. Also, additional Common Shares may be issued by the Corporation on the exercise of stock options under the Corporation's stock option plan.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Emission Regulation

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called “greenhouse gases”. The Government of Canada is in the process of developing future regulatory requirements that are expected to set greenhouse gas emission reduction requirements for various industrial activities, including oil and gas exploration and production. Questerre’s exploration and production facilities and other operations and activities emit a small amount of greenhouse gases which will likely subject Questerre to federal law regulating emissions of greenhouse gases if and when such requirements come into force. Future federal legislation, together with provincial emission reduction requirements, such as those contained in Alberta’s Climate Change and Emissions Management Act, British Columbia’s Greenhouse Gas Reduction (Cap and Trade) Act, and proposed in Saskatchewan’s Bill 126: Management and Reduction of Greenhouse Gases Act, may require the reduction of emissions or emissions intensity with Questerre’s operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of Questerre.

International Financial Reporting Standards

The Accounting Standards Board of the Canadian Institute of Chartered Accountants has announced that Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards (“**IFRS**”) as issued by the International Accounting Standards Board, effective January 1, 2011. The Company has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of 2010 required comparative information. The transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect the Corporation’s reported financial position and results of operations.

INDUSTRY CONDITIONS

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the relevant legislation and regulations. It is not expected that any of such controls and regulations will affect the operations of the Corporation in a manner materially different than they will affect other oil and gas companies of similar size.

Pricing and Marketing – Oil

Producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends on oil quality, price of competing oils, distance to market and the value of refined products. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the “**NEB**”). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

The price of natural gas sold in intra-provincial and inter-provincial trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. The price received by the Corporation depends, in part, on the prices of competing natural gas and other substitute fuels, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply and demand balance and other contractual terms. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

The governments of British Columbia, Alberta and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve ability, transportation arrangements and market considerations.

The lack of firm pipeline capacity continues to limit the ability to produce and market natural gas production although pipeline expansions are ongoing. In addition, the pro-rationing of capacity on the interprovincial pipeline systems continues to limit natural gas exports.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S or Mexico will be allowed provided that the restrictions are otherwise justified under certain provisions of the General Agreement on Tariffs and Trade and then only if any export restrictions do not: (i) reduce the proportion of the energy resource exported relative to the total supply of energy resource (based upon the proportion prevailing in the most recent 36 months); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory boarder restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to avoid discriminatory actions and to minimize disruption of contractual arrangements.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, 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. Oil and natural gas royalty rates vary from province to province.

On February 16, 2007, the Alberta Government announced that a review of the Province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil and gas resources, including oil sands, conventional oil and gas and coalbed methane, would be conducted by a panel of experts with the assistance of individual Albertans and key stakeholders. On September 18, 2007, the Royalty Review Panel delivered its final report and recommendations to the Government of Alberta. The report titled "Our Fair Share", recommended significant increases to royalties levied on natural gas, conventional oil and oil sands produced in Alberta. On October 25, 2007, the Alberta Government released details of its planned implementation of the final Royalty Review Panel report, titled "The New Royalty Framework" ("NRF"). Questerre reviewed the modifications by the Government of Alberta to its royalty program, which took effect on January 1, 2009, and provides the following observations:

- In 2009, approximately 55% of Questerre's production is from properties located outside Alberta and is therefore not affected by the NRF.

- Royalties determined under the NRF will be determined based on commodity prices, well productivity and depth of wells. A significant portion of Questerre's wells are lower productivity wells that, on a relative basis, are less impacted by the NRF than higher productivity wells.

- The NRF will have a negative impact on the economics of any future drilling.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta, which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. The new well incentive program applies to wells commencing production of conventional oil and natural gas between April 1, 2009 and March 31, 2011 and provides for a maximum 5% royalty rate for the first twelve months of production, up to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. Questerre has not drilled any wells in Alberta to take advantage of this incentive.

On March 11, 2010, the government of Alberta announced that the following will become permanent features of the royalty structure, effective with the January 2011 production month:

- Permanent 5% front-end royalty
    - The current incentive program rate of 5% on new natural gas and conventional oil wells will become a permanent feature of the royalty system, with the current time and volume limits.

- Lower Maximum Rates
    - The maximum royalty rate for conventional oil will be reduced at higher price levels from 50% to 40% to provide better risk-reward balance to investors.
    - Recognizing the fundamental changes to the North American supply/demand balance and increased competition from other jurisdictions, the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50% to 36%.

- Implementation/Transition
  - All royalty curves will be finalized and announced by May 31, 2010 and be effective for all production January 1, 2011.
  - The transitional royalty framework for oil and gas introduced in November 2008 will continue until its original announced expiration on December 31, 2013. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. Wells that have already selected the transitional royalty rates will have the option to stay with those rates or switch to the new rates effective January 1, 2011.
  - The drilling royalty credit will continue until expiry on March 31, 2011 and all other programs will continue as designed.

As part of the recognition of the significant changes in the North American natural gas market, the government will continue to analyze various components of natural gas royalties. The conclusion of this analysis will be included in the final royalty curve revisions to be announced on May 31st. Once Questerre receives the final royalty curves then the impact of the changes can be analyzed at that time.

The general oil and gas royalty structure in British Columbia is based on a sliding scale. As the price the producer receives for the gas goes up, so do the royalties that producer pays to the Province. However, the majority of gas produced in the province is also subject to a hard cap on the percentage of royalties paid. Parts 10 and 11 of the *Petroleum and Natural Gas Act* (the "**PNG Act**"), contain the primary legislative provisions for royalties and freehold production taxes on oil and gas in British Columbia. The Crown receives a royalty on any oil and gas production from Crown Land "permitted, licensed or leased" under the PNG Act. Authority is given to prescribe by Regulation the royalty rate, who must pay it, when it must be paid, as well as penalties for late or non-payment, and any other related considerations. The calculation of royalties payable for different classes of petroleum and natural gas and most of the practices and procedures to be followed are set out in the Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation. Natural gas is divided into ten categories, each with different royalty rates, which vary depending on the type of gas it is, whether it is freehold or Crown reserve and whether it is conservation or non-conservation gas. The results of failing to pay the royalties due can be significant, ranging from the imposition of penalties and interest to the Minister outright cancelling a permit, licence or lease pursuant to Section 135 of the PNG Act. The government has developed a number of royalty credit programs for certain types of drilling and wells. These include: the Summer Royalty Program; the Low Productivity Program; the Deep Royalty Program; the Deep Discovery Royalty Program; the Deep Re-Entry Royalty Program; the Marginal Royalty Program; the Ultra-Marginal Royalty Program; the Coalbed Methane Royalty Program; the Infrastructure Royalty Program; and the Net Profit Royalty Program. Some of these credits, including the Deep Well Program, Summer Program and Coalbed Methane Program, result in a dollar amount being deducted from the royalty amount owed. Others, such as the Low Productivity, Coalbed Methane, Marginal and Ultra-Marginal Royalty programs, result in a reduction of the percentage of royalties owed on each cubic metre of gas. The Infrastructure and Net Profit Royalty programs are designed to compensate producers for specific construction or drilling projects that must be approved in advance.

Under the British Columbia royalty regime, a temporary 2% gas royalty program was introduced effective September 1, 2009 whereby all natural gas wells with a spud date after August 31, 2009 and before July 1, 2010 are eligible for the 2% gas royalty, for a 12 month period, provided they commence continuous production before December 31, 2010.

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" and "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("RTR") as a response to the Government of Canada disallowing Crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the *Oil and Gas Conservation Act* and the Oil and Gas Conservation Regulations, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

The current royalty regime in the province of Québec for natural gas production is based on production volumes. The royalty rate, calculated on a well by well basis, is 10% for average daily production less than 3 MMcf and 12.5% for production in excess of this amount. In March 2009, the Québec government announced proposed changes to the regulations including:

- the implementation of a five-year royalty holiday of up to $800,000 per well for wells put into production by the end of 2010;
- the participation of the Société générale de financement du Québec (SGF) to apply the tools at its disposal to support the development of this industry in Québec;
- implementation of a program for the acquisition of geoscientific knowledge; and
- implementation of a strategic environmental assessment program.

Land Tenure

Crude oil and natural gas is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. 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

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases of emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites are abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licences and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders.

Applicable provincial environmental laws in British Columbia, Alberta, Saskatchewan and Québec are primarily found in the *Environmental Management Act, Environmental Protection and Enhancement Act, Environmental Management and Protection Act, and Environmental Quality Act*, respectively. Environmental standards and compliance for releases, clean-up and reporting in each province are strict, and there is a range of enforcement actions available, with often severe penalties. All of these provinces review energy projects through environmental assessment processes, which may be held in conjunction with a federal assessment. These review processes involve public participation. Federal environmental laws such as the *Canadian Environmental Protection Act*, 1999 and the *Fisheries Act* also apply in a variety of circumstances.

Climate change is an issue that is increasingly subject to government regulation. Although Canada has ratified the Kyoto Protocol, it remains uncertain whether the targets in the Kyoto Protocol will be enforced in Canada. British Columbia, Alberta, Saskatchewan, Québec and the federal Government have all introduced climate change action plans that include various means of achieving emissions or emissions intensity reductions, which may include direct reductions, emissions trading, carbon capture and storage, technology fund contributions, taxes on greenhouse gas emissions and credit for early action. Coordination between these plans has not yet been developed and remains a source of uncertainty. Given the evolving regulatory schemes related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict the final form these requirements will take or the impact on Questerre and its operations and financial condition at this time.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, namely, (i) making improvement to operations that result in reductions; (ii) purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emissions; or (iii) contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province of Alberta, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

Environmental legislation in British Columbia has largely been consolidated into the *Environmental Management Act* (British Columbia) (the "EMA"). In addition, the Province has passed several pieces of legislation addressing greenhouse gas emissions, such as the *Carbon Tax Act, Greenhouse Gas Reduction Targets Act, and Greenhouse Gas Reduction (Cap and Trade) Act*, although not all provisions are currently in force. British Columbia facilities emitting more than 10,000 tonnes of greenhouse gases a year must record and report their emission levels from 2010 onwards, which is intended to form the basis for a future emissions reduction system. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation in British Columbia will continue. In addition, the Government of British Columbia has outlined strategies and initiatives in a Climate Action Plan (released June 2008) which are intended to take B.C. approximately 73% towards meeting its goal of reducing greenhouse gas emissions in the province by 33% by 2020. The Province's current Energy Plan (released February 2007) sets targets for zero net greenhouse gas emissions from electricity generation, the elimination of routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half by 2011, new investments in innovation, and other measures aimed at clean energy leadership.

DIVIDENDS OR DISTRIBUTIONS

Questerre has not paid any dividends or made any distributions on its common shares since incorporation. Dividends or distributions on its common shares will be paid solely at the discretion of Questerre's board of directors after taking into account the financial condition of Questerre and the economic environment in which it is operating. No dividends or distributions are expected to be paid in the foreseeable future.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of the Corporation consists of an unlimited number of Common Shares, an unlimited number of Class B common voting shares ("**Class B Shares**") and an unlimited number of preferred shares, issuable in one or more series ("**Preferred Shares**"). As at the date hereof, 229,722,143 Common Shares, no Preferred Shares and no Class B Shares were issued and outstanding. The following is a description of the rights, privileges, restrictions and conditions attaching to the Common Shares, the Class B Shares and the Preferred shares.

Common Shares and Class B Shares

The holders of Common Shares and Class B Shares are entitled to receive notice of and to attend at and to vote one vote per Common Share or Class B Share, as the case may be, at meetings of shareholders of the Corporation, except meetings at which only holders of a specified class of shares are entitled to vote. In addition, the holders of Common Shares are entitled to receive dividends declared on the Common Shares, subject to the rights of the holders of shares ranking prior to the Common Shares, and the holders of Class B Shares are entitled to receive dividends declared on the Class B Shares, subject to the rights of the holders of shares ranking prior to the Class B Shares. Holders of Common Shares and Class B Shares are entitled to receive *pro rata* the remaining property of the Corporation upon dissolution in equal rank with the holders of other Common Shares and Class B Shares.

Preferred Shares

The Preferred Shares may be issued from time to time in one or more series, each series consisting of a number of Preferred Shares as may be determined by the board of directors of the Corporation who may also fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. Unless the directors otherwise specify in the articles of amendment designating a series of Preferred Shares, the holder of each series of Preferred Shares shall not, as such, be entitled to receive notice of or vote at any meeting of shareholders, except as otherwise specifically provided in the ABCA. The Preferred Shares of each series shall, with respect to payment of dividends and distributions of assets in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, be entitled to preference over the Common Shares and Class B Shares and over any other shares of the Corporation ranking by their terms junior to the Preferred Shares of that series.

MARKET FOR SECURITIES

Price Range and Volume of Trading of Common Shares

The following tables set forth the reported high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the common shares of Questerre on the Toronto and Oslo Stock Exchanges as reported by sources Questerre believes to be reliable for the periods indicated:

Toronto Stock Exchange

		Price Range (C$)		
		High	Low	Trading Volume
2009				
	January	2.19	1.49	11,281,684
	February	1.68	0.85	11,054,792
	March	1.44	0.78	8,581,516
	April	1.46	1.10	8,741,467
	May	1.54	1.20	8,369,896
	June	1.82	1.30	9,857,732
	July	1.46	1.15	5,045,110
	August	1.80	1.45	7,032,677
	September	2.68	1.79	17,341,937
	October	2.86	2.12	8,697,108
	November	2.55	2.23	3,977,778
	December	3.07	2.27	5,927,062
2010				
	January	3.98	3.03	10,547,616
	February	5.40	2.96	18,797,989
	March (1 - 25)	4.68	3.80	16,468,815

Oslo Stock Exchange

		Price Range (NOK)		
		High	Low	Trading Volume
2009				
	January	13.20	8.30	44,195,427
	February	9.28	4.72	27,489,933
	March	7.75	4.65	46,984,358
	April	8.00	6.08	30,258,683
	May	8.50	6.74	30,773,980
	June	10.25	7.40	44,347,141
	July	8.59	6.60	15,160,528
	August	10.40	8.06	56,407,830
	September	14.80	9.90	99,251,124
	October	15.10	11.30	50,133,593
	November	13.55	11.60	26,628,464
	December	17.40	12.50	43,257,206
2010				
	January	22.00	16.30	133,035,491
	February	30.80	15.70	128,474,563
	March (1-25)	27.30	22.10	70,867,234

PRIOR SALES

The following table sets forth, for each class of securities of the Corporation that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the financial year ended December 31, 2009 and the number of securities of the class issued at that price and the date on which the securities were issued.

Class of Securities	Issue Price or Exercise Price $	Number of Securities Issued	Date of Issue
Stock Options	1.80	1,065,000	January 8, 2009
Stock Options	2.47	2,205,000	November 4, 2009
Stock Options	2.37	250,000	December 11, 2009

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As at the date hereof, except as disclosed below the Corporation does not have any securities in escrow or that are subject to contractual restriction on transfer. The 19,972,000 Common Shares issued by the Corporation in March 2010 in Norway are not permitted to be traded on the Toronto Stock Exchange until July 10, 2010.

DIRECTORS AND OFFICERS

The following table sets forth the names and residences of the officers and directors of the Corporation, their position and offices with the Corporation, the periods during which they have served as officers or directors of the Corporation and their principal occupations for the past five years.

Name and Municipality of Residence	Offices Held and Time as Director or Officer	Principal Occupation During the Last Five Years
Leslie R. Beddoes, Jr. (5) Director Victoria, British Columbia, Canada	Director since November 2000	Independent exploration consultant since 1997.
Michael R. Binnion (3)(4)(6) President, Chief Executive Officer and Director Calgary, Alberta, Canada	President, Chief Executive Officer and director since November 2000	President, Chief Executive Officer and director of Questerre. President and director of TAC and its successor Terrenex from October 1995 to August 2009.
Pierre Boivin (6) Director Montreal, Québec, Canada	Director since August 2008	President and Chief Executive Officer of the Montreal Canadiens, the Gillett Entertainment Group and the Bell Centre since 1999.
Russ Hammond (3)(4) Director London, England	Director since December 2000	Independent businessman since 1986. Director of ECO Recycling Systems Ltd., an environmental services company, since 2000.
Peder N. Paus (2)(3)(4) Director Oslo, Norway	Director since December 2000	Independent businessman since 1995. Chairman and Director of Dora AS, a private Norwegian real estate development company.
Patrick Quinlan (2)(5) Director Calgary, Alberta, Canada	Director since December 2009	Vice president of Capgemini since May 2000.
Bjorn Inge Tonnessen (2)(5) Director Oslo, Norway	Director since November 2007	Managing Director in Norway and Executive VP Business Development for the Svenska Group, a private Swedish exploration and production company since September 2007. Formerly senior energy analyst with DnB NOR Markets ASA from January 2003 to July 2007.
Maria Rees Corporate Secretary Calgary, Alberta, Canada	Corporate Secretary since November 2000	Corporate Secretary of Questerre and Controller from November 2000 to August 2006. Controller and Corporate Secretary of TAC and its successor Terrenex from 1995 and a director from November 2000 to August 2009.
John Brodylo, P. Geol Vice President, Exploration Calgary, Alberta, Canada	Vice President, Exploration since January 2004	Vice President, Exploration of Questerre. Exploration Manager of the Corporation from March 2001 to January 2004.

Name and Municipality of Residence	Offices Held and Time as Director or Officer	Principal Occupation During the Last Five Years
Rick Tityk Vice President, Land Calgary, Alberta, Canada	Vice President, Land since November 2005	Vice President, Land of Questerre. Lead Land Negotiator with Hunt Oil Company of Canada, Inc. from July 2003 to October 2005.
Peter Coldham, P. Eng., MBA Vice President, Engineering & Operations Calgary, Alberta, Canada	Vice President, Engineering and Operations since December 2005	Vice President, Engineering and Operations of Questerre. VP Business Development for Fortune Energy, Inc., a private exploration and production company from April 2002 to November 2005.
Jason D'Silva Chief Financial Officer Calgary, Alberta, Canada	Chief Financial Officer since 2005	Chief Financial Officer of Questerre. Manager, Investor Relations of Questerre since November 2000 and Treasurer since May 2003. Vice President Finance from August 2004 – October 2008.
Paul Harrington Vice President, Finance Calgary, Alberta, Canada	Vice President, Finance since October 2008	Vice President, Finance of Questerre. Prior thereto - Director, Financial Reporting at Zargon Energy Trust from October 2005 to October 2008. From September 2001 to October 2005 employed in the audit group at PricewaterhouseCoopers LLP.

Notes:

(1) The term of office of each director will expire at the end of the next annual meeting of shareholders of Questerre, or until successors are elected or directors vacate the offices in accordance with Questerre's by-laws.
(2) Audit Committee member which committee is required pursuant to the ABCA.
(3) Corporate Governance and Nominating Committee member.
(4) Compensation Committee member.
(5) Reserve Committee member.
(6) Government Relations Committee member.
(7) Questerre does not have an Executive Committee.

The directors and officers of Questerre, as a group, beneficially own, directly or indirectly, or exercise control or direction over, 20,820,682 Common Shares or approximately 9% of the outstanding Common Shares.

The information as to shares beneficially owned, directly or indirectly or over which control or direction is exercised, is based upon information furnished to the Corporation by the respective individuals indicated.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

None of the directors or executive officers of the Corporation (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, 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 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.

Except as set forth herein, none of the directors or executive officers of the Corporation (nor any personal holding company of any of such persons), or securityholder holding a sufficient number of our securities to affect materially the control of us is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) 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 has, within the ten years before the date of this Annual Information Form, 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.

With the exception of Mr. Boivin, Mr. Tonnessen, Mr. Harrington, Mr. Tityk and Mr. Coldham, all of the current directors and officers were directors and/or officers of the Corporation in 2004. Mr. Binnion and Mr. Beddoes are also directors of QBR. On April 1, 2004, QBR applied for and was granted an order by the Court providing for creditor protection under the CCAA. On June 23, 2004, Questerre was granted protection under the CCAA and was added as a petitioner in QBR's CCAA proceedings. The filing was made to facilitate the creditor plans for the settlement of all claims in connection with the re-entry of a well at the Beaver River Field in British Columbia (the "**Creditor Plans**").

On August 9, 2004, the Corporation and QBR filed the Creditor Plans. The Creditor Plans were approved by the requisite majority of unsecured creditors at meetings of Creditors of Questerre and QBR held on August 31, 2004. The Creditor Plans were subsequently sanctioned by the Court on September 9, 2004 and implemented shortly thereafter. Questerre and QBR subsequently emerged from Court protection on October 8, 2004.

Russ Hammond and Maria Rees are each directors of Magnus and Magnus One Energy Corp. On June 18, 2008, Magnus and Magnus One applied for protection under the *Bankruptcy and Insolvency Act* (Canada). At meetings of the secured and unsecured creditors of the Magnus Entities held on September 30, 2008, the creditors approved a proposal to settle amounts outstanding. Final court approval for this proposal was received in April 2009. Subject to the resolution of contingent creditor claims, implementation of the proposal is expected to be completed in the first half of 2010.

No director or executive officer of the Corporation (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

Under Multilateral Instrument 52-110 *Audit Committees*, the Corporation is required to include in its Annual Information Form the disclosure required under Form 52-110F1 with respect to its audit committee, including the text of its audit committee charter, the composition of the audit committee and the fees paid to the external auditor. This information is provided in Appendix D and Appendix E attached hereto.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as set forth herein, the management of the Corporation is not aware of any material interests, direct or indirect, of any directors or executive officers of the Corporation, any person or which beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding common shares of the Corporation, or any known associate or affiliate of such persons, in any transaction within the last three financial years of the Corporation, or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation.

Mr. Binnion, Mr. Hammond, Mr. Paus, Ms. Rees and Mr. D'Silva were directors and/or executive officers of Terrenex prior to the acquisition (the "**Terrenex Acquisition**") of all of the issued and outstanding common shares of Terrenex ("**Terrenex Shares**") by the Corporation effective April 30, 2008. Mr. Binnion owned 428,711 Terrenex Shares, Mr. Paus owned 510,835 Terrenex Shares, Ms. Rees owned 57,000 Terrenex Shares and Mr. D'Silva owned 296,000 Terrenex Shares. Pursuant to the Terrenex Acquisition, each of the Terrenex shares were exchanged for 4.7 Common Shares. The directors and officers of Terrenex and their associates and affiliates, as a group, owned, directly or indirectly, or exercised control or direction over, and aggregate of 1,292,546 Terrenex Shares which were exchanged for 6,074,967 Common Shares pursuant to the Terrenex Acquisition.

TRANSFER AGENT AND REGISTRAR

The transfer agents and registrars for the common shares of Questerre are Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario and DnB NOR Bank ASA at its principal office in Oslo, Norway.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, there are no material contracts entered into by Questerre and still in effect as at the date hereof that can be reasonably regarded as presently material.

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, valuation or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by Questerre during, or related to, the year ended December 31, 2009 other than McDaniel, Questerre's independent qualified reserves evaluator, and PricewaterhouseCoopers LLP, Questerre's auditor. To Questerre's knowledge, none of the principals of McDaniel had any registered or beneficial interests, direct or indirect, in any securities or other property of Questerre or of Questerre's associates or affiliates either at the time they prepared the statement, report, valuation or opinion prepared by it, at any time thereafter or to be received by them.

The Corporation's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 25, 2010 in respect of the Corporation's consolidated financial statements as at December 31, 2009 and 2008 and for each of the years ended December 31, 2009 and 2008. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

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 Questerre or any associate or affiliate of Questerre.

CONFLICTS

There are potential conflicts of interest to which the directors and officers of Questerre will be subject in connection with the operations of Questerre. In particular, certain of the directors and officers of Questerre are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Questerre or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Questerre. See "Directors and Officers". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

LEGAL PROCEEDINGS

To the knowledge of the Corporation, there are no legal proceedings material to the Corporation to which the Corporation is or was a party to or of which any of its properties is or was the subject of, during the financial year ended December 31, 2009 nor are there any such proceedings known to the Corporation to be contemplated except as follows:

A Statement of Claim between Questerre and QBR. (plaintiffs) and Veritas DGC Inc. and Veritas Energy Services Inc. (defendants), alleging breach of contract and various duties. The amount of the claim is $28 million. In addition, the defendants are counterclaiming against the plaintiffs for $34,340. Questerre is unable to ascertain the impact of this legal action on its financial position at the present time.

On June 18, 2008, Magnus and its wholly owned subsidiary Magnus One Energy Corp. applied for protection under the *Bankruptcy and Insolvency Act* (Canada). Magnus Energy is a wholly owned subsidiary of Questerre. At meetings of the creditors of the Magnus Entities held on September 30, 2008, the creditors approved a proposal to settle amounts outstanding. Final court approval for this proposal was received in April 2009. Subject to the resolution of contingent creditor claims, implementation of the proposal is expected to be completed in the first half of 2010. No adjustments have been made to the carrying values of the liabilities pending receipt of this court approval.

REGULATORY ACTIONS

To the knowledge of the Corporation, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority during the Corporation's last financial year, (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority during the last financial year.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remunerations, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions is contained in the Corporation's management information circular to be filed in April 2010 relating to its most recent annual meeting of shareholders of the Corporation. Additional financial information is contained in the Corporation's comparative financial statements and management discussion and analysis for the year ended December 31, 2009. Additional information relating to the Corporation may be found on SEDAR at www.sedar.com and the Corporation's web site at www.questerre.com.

Additional copies of this Annual Information Form, the materials listed in the preceding paragraph, any interim financial statements which have been issued by the Corporation and any other document incorporated herein by reference will be available upon request by contacting the Corporate Secretary of the Corporation at its offices at Suite 1650 AMEC Place, 801 Sixth Avenue S.W., Calgary, Alberta T2P 3W2, Phone: (403) 777-1185 or Fax: (403) 777-1578.

APPENDIX A
FORM 51-101F2
REPORT ON RESERVES DATA
BY AN INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Questerre Energy Corporation (the "Company"):

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

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

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material 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, 2009, and identifies the respective portions thereof that we have evaluated, audited and reviewed and reported on to the Company's management:

Independent Qualified Reserves Evaluator or Auditor	Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	February 5, 2010	Canada	-	53,051	-	53,051

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. 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 report referred to in paragraph 4 for events and circumstances occurring after the preparation date.

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

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd.	Per:	*Signed "P. A. Welch"*
2200, 255 - 5th Avenue SW		P. A. Welch, P.Eng.
Calgary, Alberta T2P 3G6		President & Managing Director
		Calgary, Alberta
		Execution date: February 5, 2010.

APPENDIX B
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Questerre Energy Corporation (the "Company") are responsible for the preparation and disclosure of information with respect to the Company'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, 2009, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

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

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

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

The Reserves Committee of the board of directors has reviewed the Company'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 recommendations of the Reserve 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 will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) *"Michael Binnion"*	(signed) *"Peter Coldham"*
Michael Binnion President and Chief Executive Officer	Peter Coldham Vice President, Engineering & Operations
(signed) *"Bjorn Inge Tonnessen"*	(signed) *"Les Beddoes, Jr."*
Bjorn Inge Tonnessen Director	Les Beddoes, Jr. Director

March 25, 2010

APPENDIX C
DEFINITIONS USED FOR RESERVE CATEGORIES

The following reserves definitions are set out by the Canadian Securities Administrators in National Instrument 51-101 (NI 51-101; in Part 2 of Appendix 1 to Companion Policy 51-101CP) with reference to the COGE Handbook.

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

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology;
- specified economic conditions[1], which are generally accepted as being reasonable, and shall be disclosed.

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

Proved Reserves
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.

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

Possible Reserves
Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Development and Production Status
Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

Developed Reserves
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 (e.g., 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.

1 For the purposes of NI 51-101, the key economic assumptions will be the prices and costs used in the estimate, namely:
(a) constant prices and costs as at the last day of a reporting issuer's financial year; or
(b) forecast prices and costs.

Developed Producing Reserves
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.

Developed Non-Producing Reserves
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.

Undeveloped Reserves
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, 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 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 reserves 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 estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative 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.

Additional clarification of certainty levels associated with *reserves* estimates and the effect of aggregation is provided in Section 5.5.3 of the *COGE Handbook*.

Incorporation of these guidelines means that total corporate proved reserves reflect a conservative estimated and proved plus probable reserves reflect a current “best estimate” of the oil and gas quantities which will be recovered.

APPENDIX D
AUDIT COMMITTEE INFORMATION
REQUIRED IN AIF

The Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of directors is attached hereto as Appendix E.

Composition of the Audit Committee

The following table sets forth the names of each current member of the Audit Committee, whether such member is independent, whether such member is financially literate and the relevant education and experience of such member:

Name	Independent	Financially Literate	Relevant Education and Experience
Patrick Quinlan, Chair	Yes	Yes	Mr. Quinlan is the global leader of Capgemini's Oil and Gas Centre of Excellence (CoE); a multinational team focused on developing thought leadership, industry points of view, and value propositions specifically for the Oil and Gas sector. He has over 25 years of oil and gas experience and has worked in over 30 countries. Mr. Quinlan is a performance transformation specialist and is the original designer and developer of a portfolio of proprietary global oil and gas industry benchmarking services. His career has been spent largely in the oil and gas sector; initially as an oil and gas engineer, then as a partner at Ernst and Young for 10 years where he had various sector leadership roles; he joined Capgemini as a Vice president in May 2000 upon the disposition of its consulting business to Capgemini in May 2000. Mr. Quinlan holds a Bachelor of Engineering degree from the Technical University of Nova Scotia (Dalhousie) and a MBA from the University of Calgary.

Name	Independent	Financially Literate	Relevant Education and Experience
Bjorn Inge Tonnessen	Yes	Yes	Mr. Tonnessen is currently Executive VP for the Svenska Group, a private Swedish-based exploration and production company. As well as being the Managing Director in the Norwegian subsidiary, his main responsibility is to manage all of the Group's existing licenses, these being a mix of exploration, development and producing assets in Norway, Sweden and several countries in Africa (currently Angola, Nigeria, Ivory Coast and Guinea Bissau) He was formerly the senior energy analyst with DnB NOR Markets ASA from January 2003 to July 2007 and an equity analyst with Handelsbanken Capital Markets from October 2001 to November 2002. Prior thereto he was employed by the Svenska Group in a variety of progressively more senior roles including exploration and production manager for a large part of the company's portfolio. Mr. Tonnessen has also been working as an offshore drilling engineer for several years. Mr. Tonnessen holds a Bachelors' degree in Petroleum Engineering from Stavanger University in Norway and an MBA equivalent degree from Stockholm University in Sweden.
Peder N. Paus	Yes	Yes	Mr. Paus is currently director and Chairman of Dora AS, a private Norwegian real estate development company. He also served as a director of Terrenex Ltd., and its predecessor, a public investment holding company that was a significant shareholder of the Corporation. From 1998 to 2004, he served as a director of Flowing Energy Corporation, a junior exploration and production company operating in Alberta, and from June 1998 to June 2001 was Director of CanArgo Energy Corporation, an integrated exploration and production company operating in the Republic of Georgia. From 1981 to 1995, Mr. Paus was Chief

Name	Independent	Financially Literate	Relevant Education and Experience
			Executive Officer of North Venture Ltd., a shipping and offshore consulting firm based in London, England. In this capacity he was involved in restructuring several large private companies including the refrigerated transportation division of PPI-Del Monte Fresh Produce B.V. During this period, Mr. Paus was also engaged as special consultant to the British Ministry of Defense and Export Credits Guarantee Department of the British Government. Mr. Paus also has extensive experience in the banking and international finance sector. He was Executive Director, Member of the Executive Committee and Board of Directors of Manufacturers Hanover Limited and Vice President of Manufacturers Hanover Corporation, one of the leading US banks in the 1970s and early 1980s. He was also head of the Scandinavian division of Manufacturers Hanover Trust Co. Mr. Paus graduated from the University of California, Berkeley with a degree in Business Administration in 1971. Mr. Paus was elected director of the Corporation in December 2000.

During the year ended December 31, 2009, the Corporation has not relied on exemptions in Section 2.4, 3.2, 3.4, 3.5 or any other exemptions in NI 52-110.

Pre-Approval of Policies and Procedures

As of the date hereof the Audit Committee has not adopted specific policies or procedures in respect of the provision of non-audit services to the Corporation.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services were $80,000 in 2008 and $75,000 in 2009.

Audit – Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the Corporation's external auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements that are not reported under "Audit Fees" above were $154,500 in 2008 and $61,470 in 2009.

Tax Fees

There were no fees billed in each of the last two fiscal years for professional services rendered by the Corporation's external auditor for tax compliance, tax advice and tax planning.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Corporation's auditors other than services reported above were $57,900 in 2008 and $2,500 in 2009. In 2008 these relate to translation costs for the Corporation’s short form prospectus, internal control design assessment and documentation and preparation of the statutory financial reports for spending in the Lowlands.. The fees in 2009 relate to the preparation of the statutory financial reports for spending in the Lowlands.

APPENDIX E
AUDIT COMMITTEE MANDATE
AND TERMS OF REFERENCE

CHARTER

A. Composition and Process

1) The Audit Committee shall be composed of a minimum of three directors, all of whom shall be independent as that term is defined in *Multilateral Instrument 52-110, Audit Committees* ("NI 52-110"). An independent member of the audit committee is a member who has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Corporation's board of directors, reasonably interfere with the exercise of the member's independent judgment. Pursuant to NI 51-110, a person who is or has been, or whose immediate family member is or has been:

   i) an officer or employee of the Corporation, a subsidiary or affiliate;

   ii) an affiliate, partner or employee of a current or former internal/external auditor of the Corporation;

   iii) employed as an executive officer of an entity if any of the Corporation's current executives serve or have served on the entity's compensation committee;

   iv) a person who accepts or has accepted, directly or indirectly, a consulting, advisory or compensatory fee from the issuer or subsidiary of the Corporation;

   v) a person who is an affiliate of the Corporation or subsidiary of the Corporation

   is considered to have a material relationship with the Corporation unless the period prescribed by NI 52-110 has elapsed.

2) Members shall serve one-year terms and may serve consecutive terms, which are encouraged to ensure continuity of experience.

3) The Chairperson shall be appointed by the Board of Directors for a one-year term, and may serve any number of consecutive terms.

4) All members of the Audit Committee shall be financially literate. Financial literacy is the ability to read and understand a balance sheet, income statement and cash flow statement that present a breadth and level of complexity comparable to the Corporation's financial statements.

5) The Chairperson shall, in consultation with management and the external auditor and internal auditor (if any), establish the agenda for the meetings and ensure that properly prepared agenda materials are circulated to the members with sufficient time for study prior to the meeting. The external auditor will also receive notice of all meetings of the Audit Committee. The Audit Committee may employ a list of prepared questions and considerations as a portion of its review and assessment process.

6) The Audit Committee shall meet at least four times per year and may call special meetings as required. A quorum at meetings of the Audit Committee shall be its Chairperson and one of its other members or the Chairman of the Board of Directors.

The Audit Committee may hold its meetings, and members of the Audit Committee may attend meetings, by telephone conference if this is deemed appropriate.

7) The minutes of the Audit Committee meetings shall accurately record the decisions reached and shall be distributed to Audit Committee members with copies to the Board of Directors, the Chief Executive Officer, the Chief Financial Officer and the external auditor.

8) The Audit Committee reviews, prior to their presentation to the Board of Directors and their release, all material financial information required by securities regulations.

9) The Audit Committee enquires about potential claims, assessments and other contingent liabilities.

10) The Audit Committee periodically reviews with management, depreciation and amortization policies, loss provisions and other accounting policies for appropriateness and consistency.

11) The Charter of the Audit Committee shall be reviewed by the Board of Directors on an annual basis.

B. <u>Authority</u>

12. Appointed by the Board of Directors pursuant to provisions of the *Business Corporations Act* (Alberta) and the bylaws of the Corporation.

13. Primary responsibility for the Corporation's financial reporting, accounting systems and internal controls is vested in senior management and is overseen by the Board of Directors. The Audit Committee is a standing committee of the Board of Directors established to assist it in fulfilling its responsibilities in this regard. The Audit Committee shall have responsibility for overseeing management reporting on internal controls. While it is management's responsibility to design and implement an effective system of internal control, it is the responsibility of the Audit Committee to ensure that management has done so.

14. The Audit Committee shall have unrestricted access to the Corporation's personnel and documents and will be provided with the resources necessary to carry out its responsibilities.

15. The Audit Committee shall have direct communication channels with the internal auditors (if any) and the external auditors to discuss and review specific issues as appropriate.

16. The Audit Committee shall have the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties.

17. The Audit Committee shall set and pay the compensation for any advisors employed by the Audit Committee.

C. Relationship with External Auditors

18. An external auditor must report directly to the Audit Committee.

19. The Audit Committee is directly responsible for overseeing the work of the external auditor including the resolution of disagreements between management and the external auditor regarding financial reporting.

20. The Audit Committee shall implement structures and procedures to ensure that it meets with the external auditor on a regular basis in the absence of management.

D. Accounting Systems, Internal Controls and Procedures

21. Obtain reasonable assurance from discussions with and/or reports from management, and reports from external auditors that accounting systems are reliable and that the prescribed internal controls are operating effectively for the Corporation and its subsidiaries and affiliates.

22. The Audit Committee shall review to ensure to its satisfaction that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements and will periodically assess the adequacy of those procedures.

23. The Audit Committee shall review with the external auditor the quality and not just the acceptability of the Corporation's accounting principles.

24. Direct the external auditor's examinations to particular areas.

25. Review control weaknesses identified by the external auditors, together with management's response.

26. Review with external auditors their view of the qualifications and performance of the key financial and accounting executives.

27. In order to preserve the independence of the external auditor the Audit Committee will:

    i) recommend to the Board of Directors the external auditor to be nominated;

    ii) recommend to the Board of Directors the compensation of the external auditor's engagement; and

    iii) review and pre-approve any engagements for non-audit services to be provided by the external auditors or its affiliates, together with estimated fees, and consider the impact on the independence of the external auditor.

28. Review with management and with the external auditor any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of management that may be material to financial reporting.

29. The Audit Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting

controls or auditing matters and the confidential anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

30. The Audit Committee shall establish a periodic review procedure to ensure that the external auditor complies with the Canadian Public Accountability Regime under *Multilateral Instrument 52-108, Auditor Oversight.*

31. The Audit Committee will review and approve the Corporation’s hiring policies with regards to partners, employees and former partners and employees of the present and former auditor of the Corporation.

E. Statutory and Regulatory Responsibilities

32. Annual Financial Information - review the annual audited financial statements, including Letter to Shareholders and related press releases and recommend their approval to the Board of Directors, after discussing matters such as the selection of accounting policies (and changes thereto), major accounting judgments, accruals and estimates with management and the external auditor.

33. Annual Report - review the management discussion and analysis (“MD&A”) section and all other relevant sections of the annual report to ensure consistency of all financial information included in the annual report.

34. Interim Financial Statements - review the quarterly interim financial statements, including the Letter to Shareholders and related press releases and recommend their approval to the Board.

35. Earnings Guidance/Forecasts - review forecasted financial information and forward looking statements.

36. Review the Corporation’s financial statements, MD&A and earnings press releases before the Corporation publicly discloses this information.

F. Reporting

37. Report, through the Chairperson of the Audit Committee, to the Board of Directors following each meeting on the major discussions and decisions made by the Committee.

38. Report annually to the Board of Directors on the Committee's responsibilities and how it has discharged them.

39. Review the Committee's Charter annually and propose recommended changes to the Board.

G. Other Responsibilities

40. Investigating fraud, illegal acts or conflicts of interest.

41. Discussing selected issues with corporate counsel or the outside auditor or management.