QUESTERRE ENERGY CORPORATION

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2016

March 24, 2017

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INTRODUCTION

In this Annual Information Form ("**AIF**"), the terms "**Questerre**", the "**Corporation**" and the "**Company**" means Questerre Energy Corporation and its subsidiaries and partnership interests on a consolidated basis including information with respect to predecessor corporations.

Certain other terms used but not defined herein are defined in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("**NI 51-101**") and in the Canadian Oil and Gas Evaluation Handbook Volume I (the "**COGE Handbook**"). Unless otherwise specified, information in this AIF is as at the end of the Company's most recently completed financial year, being December 31, 2016. All financial information included in this AIF is determined using International Financial Reporting Standards, unless otherwise indicated. In this AIF, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

See "**Selected Abbreviations**", "**Forward-Looking Statements**" and "**Presentation of Oil and Gas Information**".

THE CORPORATION

Questerre 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 Class "A" common voting shares were subdivided into three new Class "A" common voting shares ("**Common Shares**") for each old Class "A" common voting share of the Corporation.

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

Inter-corporate Relationships

The Corporation has two direct wholly-owned subsidiaries, 6058931 Canada Inc., which was incorporated under the *Canada Business Corporations Act and* Questerre Energy Corporation/Jordan incorporated under the laws of Jordan.

GENERAL DEVELOPMENT OF THE BUSINESS

Business of the Corporation

Questerre is actively engaged in the acquisition, exploration, and development of oil and gas projects, in specific non-conventional projects such as tight oil, oil shale, shale oil and shale gas. Questerre holds assets in Alberta, British Columbia, Saskatchewan, Manitoba, Quebec and Jordan.

Corporate Strategy

Management of Questerre intends to leverage its specialized knowledge of non-conventional oil and gas resources to acquire and develop these projects.

To mitigate the financial and operational risks associated with its high impact non-conventional projects, the Corporation normally 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 to provide near-term cash flow and growth opportunities.

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 Company 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 "**Quebec Lowlands**") situated in Quebec. Since late 2004, the Company has also been developing a portfolio of conventional oil and gas assets, primarily in Alberta and Saskatchewan. The Company subsequently disposed of its interest in the Field in 2011.

During 2009, the Company focused on the appraisal of the natural gas potential of the Utica shale in the Quebec Lowlands. Vertical wells drilled with its partner, Repsol Oil & Gas Canada Inc. ("**Repsol**") (formerly Talisman Energy Inc.), were fracture stimulated and subsequently flow-tested. Based on the results, Questerre and Repsol began a pilot horizontal program to assess commerciality.

In the fall of 2010, the pilot program was suspended pending the results of a strategic environmental assessment of shale gas development in Quebec ("**SEA**"). Upon the completion of the SEA in 2014, the Government of Quebec commissioned a strategic environmental assessment of oil and gas development in the province and committed to introducing new hydrocarbon legislation in 2016. The legislation was passed as law in December 2016. Field activity in Quebec remains suspended pending introduction of the associated hydrocarbon regulations and the Company securing social acceptability for its activities.

In 2011, the Ministry of Energy and Natural Resources in Quebec ("**MERN**") introduced new legislation suspending the term of the exploration licenses for petroleum, natural gas and underground reservoirs in the province for a period of up to three years as determined by the Minister. Holders of these licenses are also exempted from performing the work required under the *Mining Act* (Quebec) for this period. In 2014, MERN amended this legislation by further extending the suspension until such time as determined by the Minister.

The announcement of the SEA in Quebec led Questerre to pursue unconventional oil opportunities elsewhere. In the fall of 2011, the Company assembled a portfolio of oil shale mining opportunities including prospective acreage and licensing rights to a proprietary technology to produce oil from shale.

In the fourth quarter of 2011, the Company acquired a 100% interest in two licences covering approximately 100,000 acres in the Pasquia Hills area of east central Saskatchewan. The acreage overlies an identified oil shale deposit. In the last four years, based on the results of core-hole programs, the Company has high graded its original acreage and acquired additional acreage, bringing its current land position to approximately 24,900 net acres. In 2017, the Company plans to relinquish its acreage in this area due to the prospective development not being economic at current commodity prices.

In March 2012, Questerre successfully concluded its letter of intent with Red Leaf Resources Inc. ("**Red Leaf**"), a private Utah-based oil shale and technology company. Red Leaf's principal assets are its proprietary EcoShale In-Capsule Technology to recover oil from shale and its oil shale leases in the state of Utah. Concurrently, the Company invested US$40 million in Red Leaf through participation in a US$100 million equity offering, representing an approximate 6% equity interest in the company. Through a series of subsequent transactions in 2012, Questerre increased its net investment in Red Leaf to US$40.73 million. Through this equity investment in Red Leaf, Questerre has acquired an indirect interest in Red Leaf's principal oil shale project covering approximately 17,000 acres in the Uintah Basin in southeastern Utah.

Questerre also executed a ten year non-exclusive option agreement to license Red Leaf's EcoShale In-Capsule processes and technology for any project identified by Questerre. Subject to the project meeting the criteria for commerciality, Questerre will pay Red Leaf a fee of US$2 million for each licence issued. Red Leaf will receive a gross overriding royalty on the project on mutually acceptable terms.

During 2012, the Company acquired and developed a new core area in the Kakwa-Resthaven area of west central Alberta targeting liquids-rich natural gas. The Company participated in the drilling and completion of four (1.55 net) wells in this area in 2012.

Year Ended December 31, 2014

In December 2014, the Company concluded a purchase and sale agreement to dispose of its assets in South Antler for $7 million. Production attributable to these assets was approximately 80 bbls/d of light oil and the disposition had an effective date of November 1, 2014.

In 2014, Questerre participated in the drilling of 16.0 (5.8 net) wells, comprising 13.0 (4.75 net) condensate-rich natural gas wells in Kakwa-Resthaven, Alberta and three (1.05 net) oil wells in Pierson, Manitoba. See "Other Oil and Gas Information".

Year Ended December 31, 2015

In the second quarter of 2015, the Company concluded a Memorandum of Understanding ("MOU") for the appraisal and development of oil shale acreage in the Hashemite Kingdom of Jordan ("**Jordan**"). The MOU covers an area of 388 square kilometers in the Isfir-Jafr area, approximately 200 km south of the capital, Amman. The initial term of the MOU is two years and it may be extended. In March 2017, the term of the MOU was extended by one year to May 2018. The Company estimates its financial commitments to range between $3-$5 million over the initial term.

In 2015, Questerre participated in the drilling of one (0.25 net) well in Kakwa-Resthaven, Alberta.

Year Ended December 31, 2016

In July 2016, the Company issued 26.39 million flow-through units for gross proceeds of approximately $4.75 million (the "**Flow-Through Placement**"). Each flow-through unit consists of one Common Share issued on a "flow-through" basis and one-half of one non-flow-through Common Share purchase warrant. Each whole warrant entitles the holder to purchase one additional non-flow-through Common Share at a price of $0.20 for a period of 18 months from closing.

The gross proceeds of the Flow-Through Placement were used by the Company, pursuant to the provisions of the *Income Tax* Act (Canada), to incur eligible Canadian development expenses ("**Qualifying Expenditures**") from the closing date and until December 31, 2016 on Questerre's properties. The Company incurred and renounced the Qualifying Expenditures to subscribers of the Flow-Through Units for the fiscal year ended December 31, 2016.

In November 2016, the Company completed a private placement of 15.2 million Common Shares at a price of $0.49 per Common Share for gross proceeds of approximately $7.4 million. The net proceeds from the private placement were initially used to repay indebtedness under its credit facilities and is intended to be used to fund its capital investment program for 2017 and general working capital purposes.

In November 2016, the Company reported on the independent assessment of its oil shale acreage in Jordan. See "Other Oil and Gas Information."

In December 2016, the Quebec National Assembly passed Bill 106, *An Act to implement the 2030 Energy Policy and to amend various legislative provisions* ("**Bill 106**"). Bill 106 enacts or amends various pieces of legislation relating to clean energy and oil and gas exploration in the Quebec, including the *Petroleum Resources Act* (Quebec), which sets out a comprehensive new regime governing petroleum exploration and development in Quebec.

In 2016, Questerre participated in the drilling of 3.0 (0.75 net) wells in the Kakwa-Resthaven area. See "Other Oil and Gas Information".

During 2016, the Company had its credit facilities with a Canadian chartered bank reduced to $30 million from the previous limit of $50 million. The credit facilities included a revolving operating demand facility ("**Credit Facility A**"), a non-revolving acquisition and development facility ("**Credit Facility B**") and a corporate credit card.

Recent Developments

In February 2017, the Company updated the independent assessment of its resources in the Quebec Lowlands. See "Other Oil and Gas Information" and "Appendix A Disclosure of Resource Data".

In February 2017, the Company completed a private placement of 30.8 million Common Shares at a price of $0.79 per Common Share for gross proceeds of approximately $24 million. The Company intends to use the net proceeds of the private placement to strengthen its working capital, partially financing its ongoing Montney capital program and the preliminary work for its planned pilot Utica development project in the St. Lawrence Lowlands, Quebec.

Following a review conducted in the fourth quarter of 2016, effective February 2017, the Company's credit facilities with a Canadian chartered bank were reduced to $23 million from $30 million as established in the third quarter of 2016. The credit facilities consist of a revolving operating demand loan. Any borrowings under the facility, except letters of credit, are subject to interest at the bank's prime interest rate and applicable basis point margins based on the ratio of debt to cash flow, measured quarterly. The next scheduled review of these credit facilities is in the second quarter of 2017.

In March 2017, in connection with the private placement completed by the Company in November 2016, the Company completed a subsequent private placement of 1.4 million Common Shares at a price of $0.49 per Common Share for gross proceeds of $0.7 million.

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.

DESCRIPTION OF THE BUSINESS

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 governmental authorities. As at December 31, 2016, Questerre recorded an obligation on its balance sheet of $8.73 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. See “Risk Factors” and “Industry Conditions”.

Employees

At December 31, 2016, Questerre’s work force consisted of 10 employees.

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”.

Marketing

Questerre’s crude oil, natural gas and NGL production is sold primarily through marketing companies at current market prices. Crude oil contracts are generally month to month and cancellable on 30 days’ notice, NGL contracts are generally for a period of up to one year and are cancellable on 90 days’ notice and natural gas contracts are generally for one year.

Cyclical and Seasonal Nature of Industry

Questerre’s operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on the financial condition of Questerre. Further, production of oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. See “Risk Factors”.

Specialized Skill and Knowledge

Questerre believes its success is dependent on the performance of its management and key employees, many of whom have specialized knowledge and skills relating to oil and gas operations. Questerre believes that it has adequate personnel with the specialized skills required to successfully carry out its operations. See “Risk Factors” in this Annual Information Form.

Social and Environmental Policies

Questerre is committed to meeting industry standards in each jurisdiction in which it operates with respect to human rights, environment, health and safety policies. Management, employees and contractors are governed by and required to comply with Questerre’s environment, health and safety policy as well as all applicable federal, provincial and municipal legislation and regulations. Questerre has established roles and responsibilities to facilitate effective management of its environment, health and safety policy throughout the organization. It is the primary responsibility of the managers, supervisors and other senior field staff of Questerre to oversee safe work practices and ensure that rules, regulations, policies and procedures are being followed.

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 23, 2017 (the "**McDaniel Report**") which evaluation is effective December 31, 2016. **The McDaniel Report is in respect of Questerre's conventional oil and gas properties and excludes its assets in the Quebec Lowlands and its oil shale assets 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 contain 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, 2016, 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 the **NI 51-101**. **All evaluations and reviews of future net revenue 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 revenue 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. All of the Company's crude oil, NGLs and natural gas reserves are located in Canada.**

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

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, 2016

FORECAST PRICES AND COSTS

Reserves

Reserves Category	Light & Medium Oil Gross [1] (Mbbl)	Light & Medium Oil Net [2] (Mbbl)	Heavy Oil Gross [1] (Mbbl)	Heavy Oil Net [2] (Mbbl)	Tight Oil Gross [1] (Mbbl)	Tight Oil Net [2] (Mbbl)
Proved						
Developed Producing	705.0	669.2	0.0	0.0	0.0	0.0
Non-Producing	56.1	46.6	0.0	0.0	0.0	0.0
Undeveloped	296.4	280.9	0.0	0.0	0.0	0.0
Total Proved	1,057.4	996.7	0.0	0.0	0.0	0.0
Total Probable	398.9	375.1	0.0	0.0	0.0	0.0
Total Proved & Probable	1,456.4	1,371.9	0.0	0.0	0.0	0.0

Reserves Category	Conventional Natural Gas Gross [1] (Mbbl)	Conventional Natural Gas Net [2] (Mbbl)	Shale Gas Gross [1] (Mbbl)	Shale Gas Net [2] (Mbbl)	Natural Gas Liquids Gross [1] (Mbbl)	Natural Gas Liquids Net [2] (Mbbl)
Proved						
Developed Producing	332.9	317.5	3,862.3	3,585.9	747.6	576.0
Non-Producing	293.1	261.5	813.5	743.3	173.1	138.4
Undeveloped	0.0	0.0	16,836.0	15,062.0	3,288.6	2,712.6
Total Proved	626.0	579.0	21,511.8	19,391.2	4,209.4	3,427.0
Total Probable	258.2	232.4	20,705.2	18,583.1	2,936.1	2,285.8
Total Proved & Probable	884.2	811.4	42,217.0	37,974.3	7,145.5	5,712.7

(1) Gross reserves are working interest reserves before royalty deductions.

(2) Net reserves are working interest reserves after royalty deductions plus royalty interest reserves.

SUMMARY NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2016

FORECAST PRICES AND COSTS

	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year)					Net Present Values of Future Net Revenue After Income Taxes Discounted at (%/year)					
Reserves Category	**@0.0% (M$)**	**@5.0% (M$)**	**@10.0% (M$)**	**@15.0% (M$)**	**@20.0% (M$)**	**@0.0% (M$)**	**@5.0% (M$)**	**@10.0% (M$)**	**@15.0% (M$)**	**@20.0% (M$)**	**Unit Value Before Tax @10.0% (1) ($/BOE)**
Proved											
Developed Producing	61,293.4	48,869.4	40,480.6	34,590.8	30,285.7	61,293.4	48,869.4	40,480.6	34,590.8	30,285.7	21.35
Non-Producing	9,931.1	8,344.3	7,276.6	6,511.6	5,934.1	9,931.1	8,344.3	7,276.6	6,511.6	5,934.1	20.65
Undeveloped	95,673.1	57,963.4	35,070.8	20,500.8	10,846.9	95,673.1	57,963.4	35,070.8	20,500.8	10,846.9	6.37
Total Proved	166,897.6	115,177.1	82,828.0	61,603.2	47,066.7	166,897.6	115,177.1	82,828.0	61,603.2	47,066.7	10.68
Total Probable	156,709.3	103,075.1	72,763.1	54,067.9	41,694.2	140,829.8	95,887.3	69,320.2	52,336.4	40,785.8	12.55
Total Proved & Probable	323,606.9	218,252.3	155,591.0	115,671.1	88,760.9	307,727.4	211,064.5	152,148.2	113,939.7	87,852.5	11.48

(1) The unit values are based on net reserve volumes.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2016

FORECAST PRICES AND COSTS

Reserves Category	Revenue [1] M$	Royalties [2] M$	Operating Costs M$	Development Costs M$	Abandonment & Reclamation Costs M$	Future Net Revenue Before Income Taxes M$	Income Taxes M$	Future Net Revenue After Income Taxes M$
Total Proved Reserves	508,740	77,341	134,526	122,930	7,045	166,898	0	166,898
Total Proved & Probable Reserves	888,166	141,763	236,072	178,082	8,642	323,607	15,880	307,727

(1) Includes all product revenues and other revenues as forecast.

(2) Royalties includes any net profits interests paid, as well as the Saskatchewan Corporation Capital Tax Surcharge.

FUTURE NET REVENUE
BY PRODUCT TYPE
as of December 31, 2016

FORECAST PRICES AND COSTS

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted @ 10%) M$	Unit Value [1] $/Mcf $/bbl
Total Proved Reserves	Light and Medium Oil (Including Solution Gas and By-products)	27,595	27.69
	Conventional Natural Gas (Including By-products)	186	0.36
	Shale Gas (Including By-products)	55,047	2.84
	Total	**82,828**	
Total Proved & Probable Reserves	Light and Medium Oil (Including Solution Gas and By-products)	37,649	27.44
	Conventional Natural Gas (Including By-products)	297	0.42
	Shale Gas (Including By-products)	117,644	3.10
	Total	**155,591**	

(1) Unit values are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group.

Forecast Prices and Costs Employed by McDaniel - January 1, 2017

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, 2017.

McDaniel & Associates Consultants Ltd.
Summary of Price Forecasts
January 1, 2017

Year	WTI Crude Oil $US/bbl (1)	Brent Crude Oil $US/bbl (2)	Edmonton Light Crude Oil $C/bbl (3)	Alberta Bow River Hardisty Crude Oil $C/bbl (4)	Western Canadian Select Crude Oil $C/bbl (5)	Alberta Heavy Crude Oil $C/bbl (6)	Sask Cromer Medium Crude Oil $C/bbl (7)	Edmonton Cond. & Natural Gasolines $/bbl	Edmonton Ethane $/bbl	Edmonton Propane $/bbl	Edmonton Butanes $/bbl	Inflation %	US/CAN Exchange Rate $US/$CAN
History													
2016	43.30	43.70	53.80	40.30	39.05	33.35	48.95	56.15	NA	13.05	33.80		0.760
Forecast													
2017	55.00	56.00	69.80	54.40	53.70	46.50	62.80	72.80	12.80	23.30	43.50	0.0	0.750
2018	58.70	59.70	72.70	58.90	58.20	50.50	67.60	75.80	11.80	23.70	47.90	2.0	0.775
2019	62.40	63.40	75.50	62.70	61.90	54.00	70.20	78.60	12.40	26.20	49.80	2.0	0.800
2020	69.00	70.10	81.10	67.30	66.50	58.00	75.40	84.30	13.60	28.30	56.40	2.0	0.825
2021	75.80	76.90	86.60	71.90	71.00	61.90	80.50	89.80	14.80	30.30	63.40	2.0	0.850
2022	77.30	78.40	88.30	73.30	72.40	63.10	82.10	91.60	15.00	30.90	64.70	2.0	0.850
2023	78.80	79.90	90.00	74.70	73.80	64.40	83.70	93.40	15.40	31.50	65.90	2.0	0.850
2024	80.40	81.50	91.80	76.20	75.30	65.60	85.40	95.20	16.00	32.20	67.30	2.0	0.850
2025	82.00	83.20	93.70	77.80	76.80	67.00	87.10	97.20	16.20	32.90	68.60	2.0	0.850
2026	83.70	84.90	95.60	79.30	78.40	68.40	88.90	99.20	16.60	33.60	70.00	2.0	0.850
2027	85.30	86.50	97.40	80.80	79.90	69.60	90.60	101.10	17.00	34.20	71.40	2.0	0.850
2028	87.00	88.20	99.40	82.50	81.50	71.10	92.40	103.10	17.40	34.90	72.80	2.0	0.850
2029	88.80	90.10	101.40	84.20	83.10	72.50	94.30	105.20	17.60	35.60	74.30	2.0	0.850
2030	90.60	91.90	103.50	85.90	84.90	74.00	96.30	107.40	18.00	36.30	75.80	2.0	0.850
2031	92.40	93.70	105.50	87.60	86.50	75.40	98.10	109.50	18.40	37.10	77.30	2.0	0.850
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.850

(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) Western Canadian Select at Hardisty, Alberta
(6) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality)
(7) Midale Cromer crude oil 29 degrees API, 2.0% sulphur

McDaniel & Associates Consultants Ltd.
Summary of Natural Gas Price Forecasts
January 1, 2017

Year	U.S. Henry Hub Gas Price $US/MMBtu	Alberta AECO Spot Price $C/MMBtu	Alberta Average Plantgate $C/MMBtu (1)	Alberta Aggregator Plantgate $C/MMBtu	Alberta Spot Sales Plantgate $C/MMBtu	Sask. Prov. Gas Plantgate $C/MMBtu	British Columbia Average Plantgate $C/MMBtu	British Columbia Station 2 $C/MMBtu
History								
2016	2.45	2.10	1.90	1.90	1.90	2.15	1.55	1.68
Forecast								
2017	3.40	3.40	3.20	3.20	3.20	3.30	2.90	3.03
2018	3.20	3.15	2.95	2.95	2.95	3.05	2.65	2.78
2019	3.35	3.30	3.10	3.10	3.10	3.20	2.90	3.04
2020	3.65	3.60	3.40	3.40	3.40	3.50	3.20	3.34
2021	4.00	3.90	3.70	3.70	3.70	3.80	3.50	3.64
2022	4.05	3.95	3.75	3.75	3.75	3.85	3.55	3.69
2023	4.15	4.10	3.85	3.85	3.85	3.95	3.60	3.75
2024	4.25	4.25	4.00	4.00	4.00	4.10	3.75	3.90
2025	4.30	4.30	4.05	4.05	4.05	4.15	3.80	3.95
2026	4.40	4.40	4.15	4.15	4.15	4.25	3.90	4.06
2027	4.50	4.50	4.25	4.25	4.25	4.35	4.00	4.16
2028	4.60	4.60	4.35	4.35	4.35	4.45	4.10	4.26
2029	4.65	4.65	4.40	4.40	4.40	4.55	4.15	4.31
2030	4.75	4.75	4.50	4.50	4.50	4.65	4.25	4.42
2031	4.85	4.85	4.60	4.60	4.60	4.75	4.35	4.52
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

(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, 2016 were $47.51/bbl for crude oil and NGLs and $2.55/Mcf for natural gas.

RECONCILIATION OF CHANGES IN RESERVES

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, 2016 against such reserves as at December 31, 2015 based on forecast price and cost assumptions.

	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL			TIGHT OIL			CONVENTIONAL GAS		
FACTORS	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved MMcf	Gross Probable MMcf	Gross Proved Plus Probable MMcf
December 31, 2015	1,155.5	443.5	1,599.0	-	-	-	843.1	279.9	1,123.0
Extensions & Improved Recovery		-						-	
Technical Revisions	2.7	-42.3	-39.6				-3.1	-14.7	-17.8
Discoveries		-						-	
Acquisitions		-						-	
Dispositions		-						-	
Economic Factors	-2.8	-2.2	-5.0				-121.2	-6.9	-128.1
Production	-98.0	-	-98.0				-92.9	-	-92.9
December 31, 2016	**1,057.4**	**399.0**	**1,456.4**	**-**	**-**	**-**	**625.9**	**258.3**	**884.2**

	SHALE GAS			NATURAL GAS LIQUIDS			TOTAL		
FACTORS	Gross Proved MMcf	Gross Probable MMcf	Gross Proved Plus Probable MMcf	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved Mboe	Gross Probable Mboe	Gross Proved Plus Probable Mboe
December 31, 2015	16,699.4	18,437.8	35,137.2	3,302.7	1,967.5	5,270.2	7,382.0	5,530.6	12,912.6
Extensions & Improved Recover	3,687.8	4,315.4	8,003.2	720.3	843.0	1,563.3	1,334.9	1,562.2	2,897.2
Technical Revisions	2,315.1	-1,746.5	568.6	395.9	140.5	536.4	783.9	-195.3	588.6
Discoveries		-			-		-	-	-
Acquisitions		-			-		-	-	-
Dispositions		-			-		-	-	-
Economic Factors	-110.0	-301.5	-411.5	-13.5	-14.9	-28.4	-54.8	-68.5	-123.3
Production	-1,080.5	-	-1,080.5	-196.0	-	-196.0	-489.6	-	-489.6
December 31, 2016	**21,511.8**	**20,705.2**	**42,217.0**	**4,209.4**	**2,936.1**	**7,145.5**	**8,956.4**	**6,829.0**	**15,785.4**

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.

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbls)		Tight Oil (Mbbls)		Conventional Gas (MMcf)		Shale Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Aggregate prior to 2014	62.3	371.0	-	-	-	-	5,916.4	8,887.4	1,249.8	1,877.2
2014	63.0	310.5	-	-	-	-	9,102.0	15,815.7	1,238.2	2,628.0
2015	-	296.4	-	-	-	-	2,583.3	12,486.5	514.1	2,484.8
2016	-	296.4	-	-	-	-	3,687.8	16,836.0	720.3	3,288.6

Probable Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbls)		Tight Oil (Mbbls)		Conventional Gas (MMcf)		Shale Gas (MMcf)		Natural Gas Liquids (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Aggregate prior to 2014	20.8	143.7	-	-	-	-	2,960.4	6,283.3	626.1	1,089.2
2014	21.8	119.3	-	-	-	-	10,347.3	13,974.2	1,210.9	1,961.7
2015	-	111.5	-	-	-	-	2,041.4	17,211.9	406.2	1,736.3
2016	-	111.5	-	-	-	-	4,315.4	19,535.3	843.0	2,692.6

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.

The McDaniel Report attributes 6,391.1 Mboe of reserves as “proved undeveloped”. These relate to step-out drilling locations in Manitoba, Antler and Kakwa. Questerre has scheduled drilling programs in these areas 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 and further infill and step-out locations in Kakwa. Additional production information may result in the reclassification of these reserves into proven developed producing reserves. The McDaniel Report attributes 6,059.9 Mboe of reserves as “probable undeveloped”.

Development of Undeveloped Reserves

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 in a responsible manner that balances the opportunities with its financial resources in the next 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, and 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.

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 ($ thousands)	
Year	Proved Reserves	Proved Plus Probable Reserves
2017	25,810.0	42,510.0
2018	26,488.0	40,223.0
2019	25,669.0	25,669.0
2020	24,605.0	49,322.0
2021	20,358.0	20,358.0
Total Undiscounted	122,930.0	178,082.0

Questerre estimates that its internally generated cash flow, current cash balances and conventional debt financing 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.

There can be no guarantee that funds will be available or that Questerre will allocate funding to develop all of the reserves attributable in the McDaniel Report. Failure to develop those reverses could have a negative impact on Questerre's future cash flow. Questerre does not anticipate that interest or other funding costs would make further development of any of Questerre's assets uneconomic.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

Questerre has two core areas where it currently conducts and expects to conduct the majority of its near term activity: Kakwa-Resthaven, Alberta and Antler, Saskatchewan. The Company also holds assets prospective for oil shale in Saskatchewan and Jordan and acreage prospective for shale gas in the St. Lawrence Lowlands, Quebec.

Kakwa-Resthaven, west central Alberta

The Kakwa-Resthaven area is situated approximately 75 kilometres south of Grande Prairie in west central Alberta. The Company holds an average 71% working interest in 28,640 acres in this area. Among other zones of interest, the area is prospective for condensate-rich natural gas in the deep, over-pressured fairway of the Montney formation, at a depth of approximately 3,100 metres to 3,600 metres. Economics are enhanced by relatively high liquids content, particularly condensate, and Crown royalty incentives.

Consistent with 2015, the majority of activity in the year was on its joint venture acreage where it holds a 25% working interest. In 2016, to preserve financial liquidity, the Company selectively participated in the six (1.5 net) well drilling program and held an interest in two (0.50 net) wells drilled during the year. The Company can elect to earn an interest in the remaining four wells once the operator has received net revenue equivalent to four times the drilling and completion costs and two times the equipping and tie-in costs of each well. The Company also participated in an expansion of existing infrastructure on this acreage.

Production from this area averaged 1,037 boe/d in 2016 with liquids, primarily condensate, accounting for 50% of this amount.

In 2016, the average length of the horizontal section increased to 2,297 metres or 10% longer than the prior year. Leveraging the improvements in completion design from prior years, completions benefitted from increased sand tonnage and tighter inter-treatment spacing. Over the first thirty days, average production from the six wells drilled in 2016 was 4.2 MMcfe/d or 20% higher than the wells drilled in 2015. While the initial results are encouraging the results are not necessarily indicative of long term performance or ultimate recovery from these wells.

Questerre also participated in the expansion of field infrastructure on its joint venture acreage for future development. This included the acquisition of a regenerative amine sweetening system and construction of a water storage facility. The amine sweetening system, with a design capacity of 60 MMcf/d and up to 1 tonne of sulphur per day, will replace the non-regenerative chemical sweetening process and should lower operating costs. The water storage facility will temporarily store produced water and will be used for future completion operations. Investment in field infrastructure in 2016 was approximately $3.32 million.

In 2016, limited activity was conducted on the Company's operated acreage in the area given the commodity price environment. Based on the results directly offsetting its operated acreage to the north, the Company is assessing possible development options in the second half of this year.

For 2017, subject to commodity prices and continued results, the Company plans to participate in the gross capital budget of $100 million ($25 million net) proposed by the operator. This will include the drilling of up to 8 (2.0 net) wells and additional infrastructure including gas lift facilities and pipelines.

Antler, southeast Saskatchewan

The Antler area is approximately 200 kilometres southeast from Regina in southeast Saskatchewan. The primary target is high quality light oil from the Bakken/Torquay formation, a dolomitic siltstone shale sequence at a depth of between 1,050 metres and 1,150 metres. Secondary targets include the Souris Valley, a carbonate sequence at a depth of approximately 900 metres to 1,000 metres. The Company holds an average 64% working interest in 11,351 acres in this area.

Production from this area averaged 209 bbls/d in 2016.

In 2016, activities at Antler targeted the optimization of existing production and the pilot waterflood to increase recovery of the oil in place.

The waterflood pilot consists of four horizontal wells on two sections injecting approximately 1,100 bbls/d of water into the oil pool. The preliminary results from the waterflood remain supportive of further work to assess an expansion to adjacent sections.

In 2017, the Company also plans to continue work to optimize production subject to partner participation and results.

Oil Shale Mining – Jordan and Pasquia Hills, Saskatchewan

Questerre's principal oil shale asset is its acreage in Jordan. Questerre also holds acreage prospective for oil shale in Pasquia Hills, Saskatchewan and the licensing rights to the EcoShale process, a proprietary process to produce oil from shale developed by Red Leaf. Questerre has an option to obtain licenses to utilize the Red Leaf process.

In 2016, Red Leaf was advised by its partner, a US affiliate of the French-based supermajor, Total S.A. ("**Total**") that it intends to withdraw from the joint venture to commercialize the EcoShale process. The parties are currently negotiating the terms of Total's withdrawal from the project.

As a result of this delay with the EcoShale process and low commodity prices, the Company plans to relinquish the rights to its oil shale acreage at Pasquia Hills in early 2017.

In October 2016, Questerre commissioned an independent assessment of its oil shale resources in Jordan (the "**Jordan Resource Assessment**"). See Appendix A "*Disclosure of Resource Data*".

St. Lawrence Lowlands, Quebec

The Quebec Lowlands are situated in Quebec, south of the St. Lawrence River between Montreal and Quebec City. The exploration potential of the Ouebec Lowlands is complemented by proximity to one of the largest natural gas markets in North America and a well-established distribution network.

The area is prospective for natural gas in several horizons with the primary target being the Utica shale. Secondary targets include the shallower Lorraine shale and the deeper Trenton Black-River carbonate. The majority of Questerre's acreage lies in the heart of the fairway between two major geological features — Logan's Line, a subsurface thrust fault to the east and the Yamaska growth fault to the west.

Following a successful vertical test well program in 2008 and 2009, Questerre and its partner, Repsol, began a pilot horizontal well program to assess commerciality of the Utica shale in 2010. In the fall of 2010, the pilot program was suspended while the provincial government initiated the SEA. (See "History of the Corporation").

In April 2016, the Government of Quebec released a new energy policy setting out targets to be achieved by 2030: (i) enhance energy efficiency by 15%, (ii) reduce by 40% the amount of petroleum products consumed, (iii) eliminate the use of thermal coal; (iv) increase by 25% overall renewable energy output; and (v) increase by 50% bioenergy production.

In December 2016, the Government of Quebec passed Bill 106, *An Act to implement the 2030 Energy Policy and to amend various legislative provisions*. Bill 106 enacts or amends various pieces of legislation relating to clean energy and oil and gas exploration in the Quebec, including the *Petroleum Resources Act* (Quebec), which sets out a comprehensive new regime governing petroleum exploration and development in Quebec. The date of the coming into force of the *Petroleum Resources Act* (Quebec) has not yet been set and the regulations referred to in the said act remains to be drafted and enacted.

In March 2017, the Government of Quebec enacted Bill 102, *An Act to amend the Environment Quality Act to modernize the environmental authorization scheme and to amend other legislative provisions, in particular to reform the governance of the Green Fund,* which brings a number of amendments to the *Environment Quality Act* mainly in order to modernize the authorization schemes it prescribes, in particular to take climate change issues more fully into account. These amendments will come into force gradually over the next two years.

Along with social acceptability, these hydrocarbon regulations and environmental legislation are prerequisites to the resumption of field activities to assess the Company's Utica gas discovery in the province.

In early 2017, the Company updated the resource assessment of its Utica acreage in Quebec (the "**GLJ Resource Assessment**"). See Appendix A "Disclosure of Resource Data".

Wells

As at December 31, 2016, the Corporation had an interest in 106.0 gross (50.8 net) producing and 75 gross (36.3 net) non-producing oil and natural gas wells as follows, all of which are onshore.

	PRODUCING				NON-PRODUCING			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross [1]	Net [2]	Gross	Net	Gross	Net	Gross	Net
Wells								
Alberta	-	-	34.0	10.0	12.0	5.8	20.0	7.6
British Columbia	-		2.0	1.0	2.0	1.3	-	-
Saskatchewan	60.0	36.3	-	-	29.0	18.4	-	-
Quebec	-	-	-	-	-	-	12.0	3.1
Manitoba	10.0	3.5	-	-	-	-	-	-
Total	70.0	39.8	36.0	11.0	43.0	25.5	32.0	10.7

There are no costs or work commitments associated with Questerre's non-producing properties except for annual lease payments.

Notes:

(1) "Gross" wells mean 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, 2016 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. There are no costs or work commitments associated with Questerre's non-producing properties except for annual lease rental payments.

LOCATION	Gross [1]	Net [2]	Net Area to Expire by December 31, 2017
Alberta	46,880	42,680	9,120
British Columbia	3,838	2,070	528
Saskatchewan	31,695	30,223	304
Manitoba	-	-	-
Quebec	934,940	266,280	53,335
Total	1,017,353	341,253	63,287

Notes:

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

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

Significant Factors of Uncertainties Relevant to Properties with No Attributed Reserves

There are several economic factors and significant uncertainties that affect the anticipated development of Questerre's properties with no attributed reserves. Questerre will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from these properties in the future. If Questerre's cash flow from operations or 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, if available, on terms acceptable to Questerre. Failure to obtain such financing on a timely basis could cause Questerre to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations. The inability of Questerre to access sufficient capital for its exploration and development purposes could have a material adverse effect on Questerre's ability to execute its business strategy to develop these prospects. For further information, see "Risk Factors".

Questerre estimates abandonment and reclamation costs for surface leases, wells and facilities based on its previous experience, current regulations, costs, technology and industry standards. Questerre has estimated the net present value of its total asset retirement obligations to be $8.73 million as at December 31, 2016 based on a total future liability of $11.37 million.

In the McDaniel Report, reasonable estimated future abandonment and reclamation costs for wells assigned reserves were deducted in determining the aggregate future net revenue. This is summarized below without discount and using a discount rate of 10%: The gross number of wells assigned proved reserves are 159 and the gross number of wells assigned proved plus probable reserves are 163.

	Forecast Pricing (M$)			
	Proved NPV 0%	Proved NPV 10%	Proved plus Probable NPV 0%	Proved plus Probable NPV 10%
Total abandonment and reclamation cost provision	7,045.0	1,211.0	8,642.0	1,060.0
Portion forecast to be paid during the next three years	-	-	-	-

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 has the following risk management contracts in place.

Risk Management Contract	Volumes	Average Price	Term
AECO call option sale	3,000 GJ/d	$2.70/GJ	Jan. 1, 2017 - Dec. 31, 2017
WTI Nymex call option sale	200 bbls/d	$80/bbl	Jan. 1, 2017 - Dec. 31, 2017

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, 2016, Questerre does not expect to incur current income taxes prior to 2021.

Costs Incurred

The following table summarizes Questerre's property acquisition costs, development costs and exploration costs incurred during the financial year ended December 31, 2016.

Nature of cost	Amount ($thousands)
Property Acquisition Costs:	
Proved Properties	-
Unproved Properties	-
Development Costs	3,301
Exploration Costs	10,917
Total	14,218

Exploration and Development Activities

The following table summarizes the results of exploration and development activities during the financial year ended December 31, 2016.

	Gross (1)	Net (2)
Development Wells		
Gas	3.00	0.75
Oil	-	-
Service	-	-
Dry	-	-
Exploratory Wells		
Gas	-	-
Oil	-	-
Service	-	-
Dry	-	-
Total Wells	3.00	0.75

Notes:

(1) "Gross" wells mean 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.

The Company's most important current exploration and development activities include the following:

- Development drilling for liquids-rich natural gas in the Kakwa-Resthaven area of west central Alberta;
- Implementation of a secondary recovery program for light oil in Antler, southeast Saskatchewan;
- Evaluation of the oil shale potential in Jordan; and
- Subject to the SEA, continued assessment of the Utica shale gas discovery in the St. Lawrence Lowlands, Quebec.

Production Estimates

The following table discloses the estimated average daily sales of products of Questerre through fiscal 2017 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, 2016. The Kakwa field accounts for greater than 20 percent of the estimated production disclosed below, with estimated gross proved plus probable reserves production of 1,820.6 boe/d.

	Light and Medium Crude Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Combined BOE (boe/d)
Corporation				
Proved				
Kakwa, AB	11.9	4,025.3	752.1	1,434.9
Antler, SK	235.9	-	-	235.9
Pierson, MB	43.1	-	-	43.1
Other	13.2	289.6	3.0	64.5
Total proved	**304.1**	**4,314.9**	**755.1**	**1,778.4**
Probable				
Kakwa, AB	8.6	1,042.1	203.4	385.7
Antler, SK	4.7	-	-	4.7
Pierson, MB	1.5	-	-	1.5
Other	0.3	2.6	-	0.7
Total probable	**15.1**	**1,044.7**	**203.4**	**392.6**
Total proved plus probable	**319.2**	**5,359.6**	**958.5**	**2,171.0**

Netback and Production History

The following table sets forth information respecting the Company's share of average gross daily production, average net product prices received, royalties paid, production costs and the resulting netbacks received by the Corporation in respect of light crude oil, shale and conventional natural gas and natural gas liquids for the periods indicated.

	Three Months ended			
	March 31 2016	June 30 2016	September 30 2016	December 31 2016
Average Daily Production				
Light Crude Oil and Natural Gas Liquids (bbl/d)	888	856	705	755
Shale Gas and Conventional Natural Gas (Mcf/d)	3,900	3,397	3,450	3,034
Total (boe/d)	1,538	1,422	1,275	1,261
Average Net Price Received				
Light Crude Oil and Natural Gas Liquids ($/bbl)	40.08	49.81	50.15	51.12
Shale Gas and Conventional Natural Gas ($/Mcf)	2.23	1.76	2.67	3.67
Royalties				
Light Crude Oil and Natural Gas Liquids ($/bbl)	3.10	4.96	3.29	3.33
Shale Gas and Conventional Natural Gas ($/Mcf)	0.06	(0.37)	(0.05)	(0.14)
Production Costs				
Light Crude Oil and Natural Gas Liquids ($/bbl)	9.82	14.25	15.47	11.54
Shale Gas and Conventional Natural Gas ($/Mcf)	3.08	2.96	3.44	3.02
Netbacks Received				
Light Crude Oil and Natural Gas Liquids ($/bbl)	27.16	30.60	31.38	36.25
Shale Gas and Conventional Natural Gas ($/Mcf)	(0.92)	(0.83)	(0.72)	0.79

Note: Natural gas production is predominately shale gas and light crude oil represents approximately 35% of light crude oil and NGLs.

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, 2016 for each product type.

Field	Light Crude Oil and Natural Gas Liquids (bbl/d)	Shale and Conventional Natural Gas (Mcf/d)	BOE (boe/d)	%
Kakwa-Resthaven, Alberta	527	3,058	1,037	75.5%
Antler, Saskatchewan	209	-	209	15.2%
Pierson, Manitoba	45	-	45	3.4%
Other	20	376	82	6.0%
Total	801	3,434	1,373	100%

Note: Natural gas production is predominately shale gas and light crude oil represents approximately 35% of light crude oil and NGLs.

RISK FACTORS

The business of exploring, 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.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels in various countries, have caused significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, carbon and other taxes and royalty changes that may be implemented by the new governments. In addition, the difficulties in obtaining the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced the Corporation's cash flow leading to a reduction in funds available for capital expenditures. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis in 2016 and beyond. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay all or a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds in the future to raise funds on unfavourable and highly dilutive terms.

Credit Facilities

The amount authorized under the Corporation's credit facilities is dependent on the borrowing base determined by the Corporation's lender. The Corporation is required to comply with covenants under its credit facilities which include certain financial ratio tests. In the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under its credit facilities, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under its credit facilities, the lender could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the credit facilities impose certain operating and financial restrictions on the Corporation including, but not limited to, restrictions on the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others. In addition, the credit facilities are demand facilities and could be reduced or eliminated by the lender for reasons beyond the control of the Corporation.

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. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, declines in global demand for exported crude oil commodities, and recent decisions by the Organization of the Petroleum Exporting Countries in respect of member countries' production of oil, among other factors. These recent fluctuations have had a material impact on the oil and natural gas industry. The materially lower prices since mid-2014 have resulted in a reduction of Questerre's net production revenue over prior periods. Certain wells or other projects may become uneconomic as a result of this decline or any further decline in world oil prices or a decline in 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 prior relatively higher average prices could reduce Questerre's future borrowing base, therefore reducing the bank credit available to the Corporation, and could require that a portion of any existing bank debt of the Corporation be repaid.

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

Questerre conducts an assessment of the carrying value of its assets to the extent required by International Financial Reporting Standards. If oil or natural gas prices decline, the carrying value of the Corporation's assets could be subject to downward revision, and the Corporation's earnings could be adversely affected by any reduction in such carrying value.

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 and NGLs may depend upon its ability to acquire space on pipelines which deliver these products 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, natural gas and NGLs.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that exploration expenditures 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.

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, commodity prices, geographical location, field discovery data and the type or quality of the petroleum product produced.

The Government of Quebec has introduced new interim regulations governing activities during the SEA. The Government of Quebec has stated its intention is to make Quebec's regulatory system competitive with other jurisdictions in North America. There is no assurance that this will ultimately improve the regulatory climate in Quebec.

The royalty regime in Alberta and any other jurisdictions in which the Corporation's oil and natural gas assets are located, including Quebec, may be subject to further review and changes which could adversely impact the Corporation's financial condition and operations and make future capital investments less economic. For recent changes see "Provincial Royalties and Incentives".

Impact of Future Financings on Market Price

In order to finance future operations or acquisitions opportunities, the Corporation may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Corporation cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Corporation's securities will have on the market price of the Common Shares.

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" for further information. These controls and procedures may change from time to time and Questerre's compliance with current and proposed regulations could have a material adverse impact by substantially increasing its capital expenditures and compliance costs.

Insurance

Questerre's involvement in the exploration 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. Quebec is a relatively new area for oil and gas development and therefore 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. Higher than expected costs could defer planned operations and set back the anticipated timeline for project development.

The Corporation's ability to execute projects and market oil, natural gas and NGLs 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.

Liquidity and the Company's Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Company's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Company's securities in particular.

Further, if the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The Company may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and 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, numerous other independent oil and natural gas companies and individual producers and operators.

The oil and natural 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 Questerre to incur costs to remedy such discharge. Recently, the industry has been subject to increased security of and focus on the environmental impact of drilling and completion techniques relating to the exploration for natural gas. Changes to the requirement for drilling and completion techniques could have a material impact on the ability of Questerre to drill and complete wells. Implementation of strategies with respect to climate change and reducing greenhouse gases to meet the limits required by federal or provincial governments could have a material impact on the nature of oil and natural gas operations, including those of Questerre. See "Industry Conditions – Environmental Regulation". Questerre is in material compliance with current environmental laws. 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 Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs 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%.

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 these 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, 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 may be 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.

The McDaniel Report is effective as of a specific date and has not been updated and thus does not reflect changes in Questerre's reserves since that date.

Resource Estimates

There are numerous uncertainties inherent in estimating quantities of resources and the future net revenue attributed to the Corporation's Contingent Resources, including many factors beyond the Company's control, and no assurance can be given that the indicated level of resources will be realized. The resource and associated future net revenue information for the Contingent Resources set forth herein are estimates only. In general, estimates of resources and future net revenue therefrom are based upon a number of variable factors and assumptions made as of the date on which the resource estimates were determined, such as historical production from the properties, initial production rates, production decline rates, ultimate resource recovery, the timing and amount of capital expenditures, the success of future development activities, future commodity prices, marketability of oil, NGLs and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially 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 those reasons, estimates of the resources attributable to any particular group of properties, classification of such resources based on risk of recovery and estimates of future net revenue associated with resources prepared by different engineers, or by the same engineer at different times, may vary substantially.

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. 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.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to Questerre's Contingent Resources represent the fair market value of those resources. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The estimates of Questerre's resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and variances could be material. With respect to the discovered resources (including Contingent Resources), there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to the undiscovered resources (including Prospective Resources), including the Corporation's resources located in Jordan, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

There are numerous factors and uncertainties that affect the anticipated development of the Corporation's resources.

The chances of development for the estimated resources are subject to a number of factors, including overall project economics, the employed recovery technology or technology under development, regulatory and environmental approval, the availability of markets and production facilities and political risk to the development.
The Corporation will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from its resource properties in the future. If the Corporation's funds flow from operations 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, if available, that the terms will be acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain opportunities, reduce its pace of development or terminate its operations on such properties. An inability of the Corporation to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Corporation's ability to execute its business strategy to develop its prospects.

The significant economic factors that affect the Corporation's future development of its resources are:

- future commodity prices for crude oil and natural gas (and the Corporation's outlook relating to such prices);
- the future capital costs of drilling, completing, tying in and equipping the wells necessary to develop such lands at the relevant times;
- the future costs of operating wells at the relevant times; and
- the levels of royalties applicable to productions from such lands.

The significant uncertainties that affect the Corporation's development of its resources are:

- the ability of the Corporation to obtain the capital necessary to fund the development of such lands at the relevant times;
- the future drilling and completion results the Corporation achieves in its development activities (e.g. with respect to the development of particular intervals or geographic areas, the uncertainty would be whether the initial drilling and completion results are sufficient to justify the development of such interval or geographic area);
- drilling and completion results achieved by others on lands in proximity to the Corporation's lands;

- transportation and processing infrastructure becoming available in a timeline consistent with proposed development plans;
- the availability of regulatory approvals for development of the lands and the necessary infrastructure; and
- governmental actions and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities.

Significant risk factors specific to Questerre and the projects outlined herein include the following:

- Commodity prices have been and are expected to remain volatile. Sustained low prices may compel the Corporation to re-evaluate its development plans and reduce or eliminate various projects with marginal economics. Questerre will need to be satisfied that its forecast of future industry and economic conditions and commodity prices prevailing during and after the applicable development project is sufficient to justify proceeding with development such project.
- The actual operating and other costs may vary materially from the costs assumed by GLJ. If actual operating or other costs vary materially from those assumed by GLJ, this would have an impact on the economics of the applicable project and could delay development.
- If the facilities and infrastructure do not expand in the manner and in the time frame assumed by GLJ, this would have an impact on the development schedules for Questerre's resource projects and such projects could be delayed.
- The Corporation's development activities are dependent on the availability of equipment, materials (including those needed for fracing operations) and skilled personnel. Demand for such limited equipment, materials and skilled personnel may affect the availability of such equipment, materials and skilled personnel to the Corporation and may delay the Corporation's development activities. During times of high demand, the costs of such equipment, materials and personnel may increase, resulting in increased costs to the Corporation.
- The implementation of new regulations or the modification of existing regulations regarding fracturing operations may have a material adverse impact on the Corporation's ability to develop its resources. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims and could increase the Corporation's costs of compliance and doing business. All of the foregoing could delay development.

All of these risks and uncertainties have the potential to delay the development of Questerre'sresources. On the other hand, uncertainty as to the timing and nature of the evolution of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to the development of such resources.

Questerre's resources are estimated using forecast prices and costs. These prices are above current crude oil and natural gas prices. If crude oil and natural gas prices stay at current levels, certain of Questerre's resources may become uneconomic. For further information regarding the risks and uncertainties relating to Questerre and its properties to which no reserves have been attributed, please see "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Properties with No Attributed Reserves*".

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. Irrespective of whether or not the Corporation's business and asset base change materially, the lending capacity of many financial institutions has diminished and risk premiums have increased in recent years. 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 in 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, expected adjusted funds flow from operations and available conventional debt capacity, the Corporation believes it has sufficient funds available to fund its projected capital expenditures. However, if adjusted funds flow from operations is 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 of 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.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Corporation may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect the Corporation's financial and operational results.

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 adequately handle 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 adjusted funds flow from its operations 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. Due to the conditions in the oil and gas industry and/or global economic volatility, the Company may from time to time have restricted access to additional funding.

Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in the Company's revenues from its reserves, which may affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Company'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 affected materially and adversely as a result.

If Questerre's adjusted funds flow from operations, current cash balance and available conventional debt capacity 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 natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Company's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Company's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Company receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Company's operations, which may have a negative impact on the Company's financial results.

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

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares of the Company.

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.

Liability Management

Alberta and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "Industry Conditions - *Liability Management Rating Programs*".

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 equipment may exceed supply thereof and access restrictions may affect the availability of such equipment to Questerre and may delay the Corporation's 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 it could have a material adverse effect on the Corporation and its operations.

Conflicts of Interest

Directors and officers of Questerre may also be directors and officers of other 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 to existing holders of Common Shares.

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 infrastructure 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 contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Company may be exposed to third party credit risk from operators of properties in which the Company has a working or royalty interest. 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 oil and natural gas industry and consequently of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying aspects of the program and the Corporation's anticipated results thereof until the Corporation is able to find a suitable alternative partner, if at all. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Company being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's financial and operational results.

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 issued 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 announced in 2012 that it would withdraw from the Kyoto Protocol, established under the United Nations Framework Convention on Climate Change, which set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Under the Copenhagen Accord, the intended successor to the Kyoto Protocol, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol, Canada has committed to reducing its greenhouse gases emissions by 17% from 2005 levels by 2020. 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*, Quebec's *Regulation Respecting a Cap-and-trade System for Greenhouse Gas Emission Allowances and Saskatchewan's Management and Reduction of Greenhouse Gases Act*, may require the reduction of emissions or emissions intensity with Questerre's operations and facilities or the purchase of emission allowances. The direct or indirect costs of these regulations may adversely affect the business of Questerre. The new Upstream Petroleum Industry Associated Gas Conservation Standards (the "**Gas Conservation Standards**") were announced by the Government of Saskatchewan in June 2012. The Gas Conservation Standards are designed to reduce emissions from the flaring and venting of associated gas. These standards were implemented pursuant to *The Oil and Gas Conservation Act* (Saskatchewan). The Gas Conservation Standards came into effect on July 1, 2012 for new wells and facilities licensed on or after that date. For existing wells and facilities already licensed prior to July 1, 2012, the Gas Conservation Standards have an implementation date of July 1, 2015.

Technology

The commercial scalability of Red Leaf's EcoShale In-Capsule process has not been demonstrated and is therefore unproven commercial technology relative to oil shale extraction. There can be no assurance that the EcoShale In-Capsule process will perform as expected, at scale, or that the costs to construct or operate the technology will not be significantly higher than anticipated.

Investment in Red Leaf

Questerre holds an approximate 6% of the equity of Red Leaf, representing a minority interest in the company. As a result, Questerre does not have the ability to exercise influence over the operation of Red Leaf, which could adversely affect Questerre's financial performance. Questerre's return on the Red Leaf investment will therefore depend upon a number of factors that may be outside of Questerre's control, including the timing and amount of capital expenditures, Red Leaf's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Possible Failure to Realize Anticipated Benefits of Acquisitions

As part of its ongoing strategy, the Company may complete acquisitions of assets or other entities in the future. Achieving the benefits of completed and future acquisitions depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses and entities requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Company's ability to achieve the anticipated benefits of any acquisitions.

Gathering and Processing Facilities and Pipeline Systems

The Company delivers its products through gathering, processing and pipeline systems, some of which it does not own. The amount of oil, natural gas and NGLs that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry limiting the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work because of actions taken by regulators could also affect the Corporation's production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, the Company's financial condition, results of operations and cash flows.

The Federal Government has signaled that it plans to review the National Energy Board approval for large projects. This may cause the timeframe for project approvals for current and future applications to increase.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the Safe and Accountable Rail Act which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Company's ability to process its production and to deliver the same for sale.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company. There can be no assurance that the Company will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Company or implemented in the future may become obsolete. In such case, the Company’s business, financial condition and results of operations could be materially adversely affected. If the Company is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

Hydraulic Fracturing

Concern has been expressed over the potential environmental impact of hydraulic fracturing operations, including water aquifer contamination and other qualitative and quantitative effects on water resources as large quantities of water are used and injected fluids either remain underground or flow back to the surface to be collected, treated and disposed of. Regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. Federal, provincial and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, and adversely affect Questerre’s production. Public perception of environmental risks associated with hydraulic fracturing can further increase pressure to adopt new laws, regulation or permitting requirements or lead to regulatory delays, legal proceedings and/or reputational impacts. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delay, increased operating costs, and third-party or governmental claims. They could also increase Questerre’s costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which may not be commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Questerre is ultimately able to produce from its assets.

Due to recent seismic activity reported in the Fox Creek area of Alberta, the Alberta Energy Regulator announced new seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Zone in the Fox Creek area of Alberta. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs.

In the event that other restrictions are adopted by federal, provincial, local, or municipal authorities in areas where Questerre is currently conducting, or in the future plans to conduct operations, Questerre may incur additional costs to comply with such requirements that may be material, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps be precluded from the drilling of wells. In addition, if hydraulic fracturing becomes more regulated, Questerre’s fracturing activities could become subject to additional permitting requirements that could result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Questerre is ultimately able to produce from its reserves.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent United States presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of NAFTA, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has started taking steps to implement such withdrawal. Some European countries have also experienced the rise of antiestablishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for third party lessees' operations, reduce their access to skilled labour and as a result, negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

Geopolitical Risks

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

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

Risks Associated with Interests in Jordan

Certain of Questerre's assets and operations are located in Jordan. Political, economic, legal and social conditions in Jordan, as well as in the Middle East (including Turkey) and surrounding areas could materially and adversely affect Questerre's business as it is subject to political, economic and other uncertainties that are not within its control. These include, but are not limited to, the uncertainty of negotiating with foreign governments, changes in government policies and legislation, adverse legislation or determinations or rulings by governmental authorities, currency fluctuations, currency devaluations, currency controls, high inflation, disputes between various levels of authorities, arbitrating and enforcing claims against entities that may claim sovereignty, authorities claiming jurisdiction, potential implementation of exchange controls and/or royalty regimes and increases in the government's share and other risks arising out of Jordanian sovereignty over Questerre's Jordanian assets.

Questerre's operations may also be adversely affected by social instability, changes in crude oil or natural gas pricing policy (or in the personnel administering such policy), availability of oil transport infrastructure, availability of Jordanian pipeline export infrastructure, the necessary political approvals, finding acceptable gas conservation solutions, the risks of war, terrorism, guerrilla activities, insurrections, border disputes, military repression, civil disorder, crime, abduction, expropriation of property without fair compensation, nationalization, renegotiation or nullification of existing concessions and contracts, taxation policies, economic or other sanctions (imposed by other countries or regions), the imposition of specific drilling obligations, oil export or pipeline restrictions and the development and abandonment of fields.

The inability of the Company to mitigate the political, economic and social uncertainties associated with exploring for, developing and producing, oil and gas in Jordan, may adversely impact Questerre's ability to operate its interests, export oil or realize its full economic benefits of its interests in Jordan. This may in turn negatively impact Questerre's business, financial condition, results of operations and prospects.

Additionally, there is no assurance that Jordan will not be impacted by terrorism, ISIS, the Syrian civil war or other regional instability.

The threat of terrorism remains high in Jordan. Transnational and indigenous terrorist groups have demonstrated the capability to plan and implement attacks in Jordan. Violent extremist groups in Syria and Iraq, including ISIS and Jabhat al-Nusra continue to pose a threat, in addition to al-Qa'ida. The potential for terrorist activity has heightened since Jordan took an active role in the coalition against ISIS.

If ISIS were to engage in attacks or were to occupy areas within Jordan, if instability and civil war in neighbouring Syria were to destabilize Jordan or areas thereof, or if regional instability in the Middle East were to generally increase, it could result in the Company and its joint venture partners losing operating control over, and the right to extract and sell hydrocarbons therefrom or delays in operations, additional costs for increased security and difficulty in attracting/retaining qualified service companies and related personnel, which could materially adversely impact the Company's business, financial condition and results of operations and prospects.

As a result, the Company's operations in Jordan are subject to the risk of terrorist and criminal actions.

Companies operating in countries such as Jordan may be targets for criminal or terrorist actions including those of ISIS. Criminal or terrorist action against Questerre, in particular its properties or facilities or third-party infrastructure, could have a material adverse effect on the Company's business, results of operations and financial condition. In addition, the possible threat of criminal or terrorist actions against it could have a material adverse effect on the ability of Questerre to adequately staff its operations or could materially increase the costs of doing so.

Furthermore, Questerre is exposed to the risk of a change in government relations.

Although Questerre has good relations with the Government of Jordan, there can be no assurance that the actions of present or future governments will not materially adversely affect the business or financial condition of Questerre. Questerre and its co-venturers may be unable to obtain or renew required drilling rights, licences, permits and other authorizations and/or such rights, licences, permits and other authorizations may be suspended, terminated or revoked prior to their expiration.

Any significant delay in obtaining or renewing a licence, permit or other authorization including approval of development plans, may result in a delay of the Company's planned activities in Jordan and the future development of any associated oil and gas resources. In addition, any of Questerre's existing and future drilling rights and licences, permits and other authorizations may be suspended, terminated or revoked if Questerre fails to comply with the relevant requirements of the Government of Jordan and its agencies. If Questerre or its co-venturers fail to fulfill the specific terms of any of its existing or future rights, licences, permits and other authorizations or operates its business in a manner that violates applicable law in Jordan, government regulators may impose fines or suspend or terminate the relevant right, licence, permit or other authorization, any of which could have a material adverse effect on the value of Questerre's assets in Jordan.

Tax Horizon

It is expected, based upon current legislation, the projections contained in the McDaniel Report and various other assumptions that no cash income taxes are to be paid by Questerre in the near future. A lower level of capital expenditures than those contained in the McDaniel Report or should the assumptions of Questerre in respect thereof prove to be inaccurate, Questerre may be required to pay cash income taxes sooner than anticipated, which could materially reduce cash flow available to Questerre.

Internal Controls

Effective internal controls are necessary for Questerre to provide reliable financial reports and to help prevent fraud. Although Questerre undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, Questerre cannot be certain that such measures will ensure that Questerre will maintain adequate control over financial processes and reporting.

Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm Questerre's results of operations or cause it to fail to meet its reporting obligations. If Questerre or its independent auditors discover a material weakness in such controls, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in Questerre's financial statements and materially reduce the market price of the Common Shares.

Litigation

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on the Company's assets, liabilities, business, financial condition and results of operations.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Information Technology Systems and Cyber-Security

The Corporation relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Corporation is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data, compromise confidential customer or employee information, result in the disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage. In addition, information systems could be damaged or interrupted by natural disasters, force majeure events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on the Corporation's business, financial condition, results of operations and cash flows.

In the ordinary course of business, the Corporation collects, uses and stores sensitive data, including intellectual property, proprietary business information and personal information of the Corporation's employees and third parties. Despite the Corporation's security measures, its information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions. Any such breach could compromise information used or stored on the Corporation's systems and/or networks and, as a result, the information could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties or other negative consequences, including disruption to the Corporation's operations and damage to its reputation, which could have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Forward-Looking Statements and Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking statements and information. By its nature, forward-looking statements and information involve numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties related to forward-looking statements and information are found under the heading "Forward-Looking Statements" in this Annual Information Form.

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.

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. The NEB underwent a consultation process to update the current regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "**Prosperity Act**"), which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long term licenses.

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 two years or for a term of two 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 license from the NEB and the issuance of such license 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.

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of sufficient firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. The pro rating of capacity on the interprovincial pipeline systems also continues to affect the ability to export oil and natural gas.

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 signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and natural gas industry is uncertain.

Trans-Pacific Partnership

On October 5, 2015, Canada and 11 other countries announced an agreement in respect of the Trans-Pacific Partnership ("**TPP**"). Canada and each participating country must ratify the TPP in their national legislatures. The TPP would lower tariffs on a wide range of Canadian products and benefit exporters across Canada in a number of sectors, including agriculture, wood and wood products, chemicals and plastics, and fish and seafood. An agreement would also bring enhanced and more predictable market access for Canada's services providers.

Extractive Sector Transparency Measures Act

The Extractive Sector Transparency Measures Act ("**ESTMA**"), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state owned entities, including employees and public office holders, made Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Payments to aboriginal governments are exempt from reporting obligations until 2017. Failure to comply with the reporting obligations under ESTMA are punishable upon summary conviction with a fine of up to $250,000. In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over $9,000,000 in total liability.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, NGL, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The federal government has signaled it will, inter alia, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change within 90 days of the 2015 Paris Climate Conference which concluded on December 12, 2015. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations for a new royalty regime, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF has taken effect on January 1, 2017. On April 21, 2016, the Government of Alberta released further details on the drilling and completion cost allowance and royalty formulas that will apply to non-oil sands wells drilled on or after January 1, 2017. On July 11, 2016, the Government of Alberta released details on its new strategic programs under the MRF: the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. When determining royalty rates, these programs will take into account the higher costs associated with enhanced recovery methods as well as the higher costs associated with developing emerging resources. Both the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program are application-based and companies will be required to meet established criteria in order to comply with these programs. On July 12, 2016, the Government of Alberta announced that new wells spud before January 1, 2017, may elect to opt-in early to the MRF if they meet certain criteria, changing the previously announced schedule stating that the MRF would not take effect until January 1, 2017. Early access to the new framework is optional and will be application-based. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027, unless the company elects to opt-in to the MRF.

The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. The Mid-Life phase royalty rate will range from 5% to 40% on all production, depending on the commodity price of oil. This royalty rate is intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 Mcf/d for gas, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, were released in the second half of 2016.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties, for wells drilled prior to January 1, 2017, are paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework" until January 1, 2027, unless the Company has elected to opt-in to the MRF. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 36%. Royalties on NGLs are levied at a flat rate of 30% of the sales volume for propane and butane and 40% for pentanes plus with field condensate at a rate equivalent to oil.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the Freehold Mineral Rights Tax Act (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources. These initiatives apply to wells drilled before January 1, 2017 for a 10 year period until January 1, 2027. Specifically:

- coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The MRF eliminates the various royalty credits and incentives outlined above for wells drilled after December 31, 2016. However, the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program are intended to create cost allowance programs for enhanced oil recovery schemes and higher risk experimental drilling.

The impact on the Company of any changes to applicable royalty regimes will be dependent on a number of factors, but an increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("**old oil**"), between October 31, 1975 and June 1, 1998 ("**new oil**"), or after June 1, 1998 or through an Enhanced Oil Recovery ("**EOR**") scheme ("**third-tier oil**"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to oil production on Crown land. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The freehold production tax rate for natural gas liquids is a flat 12.25%.

As of January 1, 2017, all liquid natural gas ("**LNG**") facilities are subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment, the Government of British Columbia will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's natural gas low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs that relate to locations specific factors. Effective April 1, 2014, the Deep Well Royalty Credit Program will have two tiers – "tier one" and "tier two". The existing Deep Royalty Credit Program, as described above, will comprise tier two of the program which offers a higher maximum royalty credit and attracts a 3% minimum royalty. Tier one of the Deep Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than 1,900 metres if spud on or after April 1, 2014 and attracts a 6% minimum royalty.

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date subsequent to December 1, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres.

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation.

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land.

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m^3.

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m^3 per metre of depth for exploratory wildcat wells and less than 11 m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m^3. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program.

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month. The amended regulation will be applied to royalties starting with the April 2013 production month. The 3% minimum royalty began showing on monthly gas royalty invoices starting in July 2013.

Saskatchewan

In Saskatchewan, taxes ("**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations.

The amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF"**) applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and

250 m^3 per month for “fourth tier oil”. Where average wellhead prices are below the established base prices of \$100 per m^3 for third and fourth tier oil and \$50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as “non-associated gas” (gas produced from gas wells) or “associated gas” (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth-tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth-tier gas also includes production from 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 at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$1.35 per gigajoule for third and fourth-tier gas and \$0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth-tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.** The current regulatory scheme provides for **c**ertain differences with respect to the administration of “fourth-tier gas” which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of “fourth tier oil” Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than

1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on EOR projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards will apply to existing licensed wells and facilities on July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 11 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a Company's production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Manitoba

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil which is dependent on the date of drill, re-entry, enhanced recovery project implementation date, or various other key dates. Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Quebec

The current royalty regime in the province of Quebec 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 2011, the Government of Quebec announced proposed changes to the royalty regime for the development of shale gas in the province. This regime includes a commodity price and productivity component and varies between 5% and 35%. It has been modeled on the royalty regimes in Alberta and British Columbia for conventional production.

The government also announced the introduction of a "Gas Development Program" modeled on the Net Profit Royalty Program that is used in northeast British Columbia. The progressive royalty rate starts at 2% and varies through a four-tiered scale based on the recovery of capital invested and returns achieved. The government also announced that it was eliminating a 15% tax credit for resource development and replacing it with a non-refundable royalty credit of up to 15% of eligible exploration expenses. The royalty credit cannot be used to reduce the royalty rate below 5% and the full amount of any unused portion may be carried forward to subsequent years.

In March 2012, the Government of Quebec announced:

- A review of the royalty regime for onshore oil production for wells that will begin production on March 21, 2012;
- A statement of principles for a royalty regime for offshore hydrocarbon production;
- A new license and lease regime for the exploration and production of onshore hydrocarbons based on an auction system, which came into effect on March 20, 2012; and
- A review of performance guarantees required when drilling a well in order to ensure site restoration following such activity.

The new royalty regime for oil production includes a progressive royalty rate which ranges from 5% to 40% that is calculated for each well and varies depending on the price of oil and well productivity. A special measure is to be implemented which for oil wells currently in production whose length exceeds 1500 metres. Eligible wells will benefit from a royalty rate of 5% for the first six months of production, to a maximum of 30,000 barrels. The Government of Quebec has announced that they will re-evaluate this production incentive in a few years when the oil industry is more developed.

The Paris Agreement

In December 2015, Canada and 195 other countries that are members of the United Nations Framework Convention on Climate Change met in Paris, France and signed the Paris Agreement on climate change. The stated objective of the Paris Agreement is to hold "the increase in global average temperature to well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius." The countries which agreed to the Paris Agreement committed to meeting every five years to review their individual progress on GHG emissions reductions and to consider amendments to non-binding individual country targets. Canada is required to report and monitor its GHG emissions, though the implementation of such reporting and monitoring has yet to be determined. The Paris Agreement also contemplates that by 2020 the parties thereto will develop a new market-based mechanism related to carbon trading, which is expected to be based largely on lessons learned from the Kyoto Protocol. The Government of Canada has announced that it will develop a country-wide approach to implementing the Paris Agreement in 2016.

The Corporation is unable to predict the impact of the Paris Agreement on its operations. It is possible that mandatory emissions reduction requirements may have a material adverse effect on the Corporation's financial condition, results of operations and cash flow.

Land Tenure

Crude oil and natural gas is owned predominantly by the respective provincial governments with the exception of Manitoba where private ownership accounts for approximately 80% of the crude oil and natural gas rights in the southwestern portion of the province. 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 between the parties to such lease.

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. The Government of British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007 to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses issued after January 1, 2009 at the conclusion of the primary term of the lease or license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat production and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

On a Federal level and pursuant to the *Prosperity Act*, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An expert panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the federal government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment processes. The federal government has not provided any indication on what changes, if any, will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the federal government announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how this may affect ongoing LNG export projects currently under consideration and development. On the same day, the federal government also approved the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline had been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

Alberta

The Alberta Energy Regulator (the "**AER**") is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("**IRMS**"). The IRMS method to natural resource management sets out to engage and consult with stakeholders and the public. While the AER is the primary regulator for energy development, several governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the AER, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into effect on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers approximately 93,212 square kilometres and is in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 per cent of the provinces oilsands resource and much of the Cold Lake oilsands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with preexisting tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and recreation areas will include a restriction that prohibits surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44 percent of the province's population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Phase 1 Consultation of the North Saskatchewan Region Plan ("**NSRP**") has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

British Columbia

Environmental legislation in British Columbia has largely been consolidated into the *Environmental Management Act* (British Columbia) (the "**EMA**") and the *Oil and Gas Activities Act* (the "**OGAA**"), and these statutes impact conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities in British Columbia. The OGAA came into force on October 4, 2010, consolidating the numerous statutes and regulations that formerly governed the rights and responsibilities of the petroleum and natural gas industry in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**BC Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The Environmental Protection and Management Regulation establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, and permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole, and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of The Oil and Gas Conservation Regulations, 2012 ("**OGCR**") and The Petroleum Registry and Electronic Documents Regulations ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers and procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Manitoba

In Manitoba, the Petroleum Branch of Innovation, Energy and Mines develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of crude oil and natural gas resources. Oil and gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* ("**MBOGA**") and *The Oil and Gas Production Tax Act*, and related regulations and guidelines.

Quebec

In 2011, the Bureau d'audiences publiques sur l'environment ("**BAPE**"**)** released its report on the development of the shale gas industry in Quebec. The BAPE report recommended a strategic environmental assessment ("**SEA**"), similar to studies conducted for large scale projects in international jurisdictions.

Also, in 2011, the Quebec government enacted *An Act to limit oil and gas activities* which imposed a moratorium on oil and gas activities in the St. Lawrence River upstream of Anticosti island and exempted holders of a licence to explore for petroleum, natural gas and underground reservoirs from performing the exploration work required by the *Mining Act*. In June 2014, *An Act to amend the Act to limit oil and gas activities and other legislative provisions* was enacted to temporarily extend the application of the Act to limit oil and gas activities.

In May, 2014, the Government of Quebec announced its action plan for hydrocarbon development. The action plan included, among other things, the acquisition of knowledge through the pursuit of a global SEA on the hydrocarbon sector. The action plan also contemplated the modernization of the legislative and regulatory framework devoted specifically to hydrocarbon resources to allow for their safe development in Quebec, taking into account protection of the environment, local populations and local water resources.

Between 2009 and 2016, four SEAs were completed at the request of the Government of Quebec: (i) SEA on marine environment, (ii) SEA on Shale Gas, (iii) SEA on Île d'Anticosti and (iv) SEA on the hydrocarbon sector. Overall, the SEAs provided recommendations on social, environmental, economic, safety, transport and greenhouse gas issues. Among the main findings, the modernization of the legislative and regulatory framework governing hydrocarbons in Quebec was identified as being necessary.

Environmental legislation in Quebec is mostly contained into the *Environment Quality Act* (the "**EQA**") and its regulations, including, without limitation, the *Water Withdrawal and Protection Regulation*, which came into force in 2014/2015 and which sets out new requirements relating to drilling sites used to explore for or produce petroleum products. Further environmental requirements applicable to the natural gas industry are contained in the *Mining Act* and its regulations as well as in other various legislation. The EQA was amended in 2011 to implement new potential sanctions for the violation of its provisions and those contained in its regulations, including a significant increase in the amounts of the fines that may be imposed, a presumption of liability for directors and officers for environmental offences committed by a corporation, solidary liability of directors and officers for the payment of amount due to the Ministry of Environment, Sustainable Development and Parks in Quebec, now the Ministry of Sustainable Development, Environment and the Fight against Climate Change ("**MDDELCC**"), an administrative monetary penalty system and a power to revoke, modify, suspend or refuse environmental permits in certain situations.

In March 2017, the Government of Quebec adopted Bill 102, *An Act to amend the Environment Quality Act to modernize the environmental authorization scheme and to amend other legislative provisions, in particular to reform the governance of the Green Fund*, which brings a number of amendments to the *Environment Quality Act* mainly in order to modernize the environmental schemes it prescribes, in particular to take climate change issues more fully into account. These amendments will come into force gradually over the next two years.

Further environmental requirements applicable to the natural gas industry are currently contained in the *Mining Act* and its regulations. Such environmental requirements will however be replaced upon the coming into force of the *Petroleum Resources Act* set by Bill 106, *An Act to implement the 2030 Energy Policy and to amend various legislative provisions*, which was assented in December 2016. Bill 106 enacts or amends various pieces of legislation relating to clean energy and oil and gas exploration in Quebec, including the *Petroleum Resources Act*. The purpose of the *Petroleum Resources Act* is to govern the development of petroleum resources while ensuring the safety of persons and property, environmental protection, and optimal recovery of the resource, in compliance with the greenhouse gas emission reduction targets set by the Government. Once in force, the *Petroleum Resources Act* will establish an authorization scheme applicable to exploration, production and storage of petroleum. It will set out a comprehensive regime governing the issuance of exploration licences, production licences and storage licences. The *Petroleum Resources Act* will also require authorizations or approvals for other activities related to petroleum resource exploration and production activities, including geophysical and geochemical surveying, stratigraphic surveying, well drilling, re-entry and completion activities, and workover and reconditioning work. In addition, the *Petroleum Resources Act* will notably set requirements relating to well closure, site restoration and community involvement as well as provide for a special liability regime for licensees. The date of the coming into force of the *Petroleum Resources Act* (Quebec) has not yet been set and the regulations referred to in the said act remains to be drafted and enacted.

Pending the coming into force of the *Petroleum Resources Act*, the MDDELCC has published interim guidelines for oil and gas exploration which take into account existing relevant regulations and administrative provisions for the supervision, monitoring and environmental control of exploration and development projects.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The *Oil and Gas Conservation Act* (Alberta) establishes an orphan fund (the "**AB Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The AB Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licencees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes were implemented over a three-year period ending in 2015. The changes to the AB LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On July 4, 2014, the AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment.

As a result of the Redwater Energy Corp. bankruptcy court ruling, whereby the court found that receivers and trustees of AER licensees may selectively disclaim unprofitable assets (and their associated abandonment and reclamation obligations) under section 14.06 of the federal *Bankruptcy and Insolvency Act*, the AER and the Orphan Well Association are actively working on appropriate regulatory measures to mitigate the liability impact of licensee's abandonment, reclamation and remediation obligations from falling back to the industry. Consequently, on June 20, 2016, the AER issued Bulletin 2016-16 Licensee Eligibility – Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("**Bulletin 16**") which includes an interim rule that as a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management ratio ("**LMR**") of 2.0 or higher immediately following the transfer. If the transfer of the licensee does not improve the purchaser's LMR to 2.0 (or higher), the purchaser can post a security deposit, address existing abandonment obligations or transfer additional assets.

In order to clarify and revise the interim rules in Bulletin 16, the AER issued Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("**Bulletin 21**") on July 8, 2016 and reaffirmed its position that a LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, Bulletin 21 did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if: (i) the licensee already has a LMR of 2.0 or higher; (ii) the acquisition will improve the licensee's LMR to 2.0 or higher; or (iii) the licensee is able to satisfy its obligations, notwithstanding a LMR below 2.0, by other means. The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the Redwater decision on October 11, 2016, with the Court reserving its decision.

British Columbia

In British Columbia, the BC Commission implements the Liability Management Rating Program (the "**BC LMR Program**"), designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the BC Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**SK Orphan Fund**") established under the SKOGCA. The SK Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Manitoba

To date, Manitoba has not implemented a liability management rating program similar to those found in the other western provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the Drilling and Production Regulations. In certain circumstances, a performance deposit may be refunded. The MBOGA also establishes the Abandonment Fund Reserve Account (the "**Abandonment Fund**"). The Abandonment Fund is a source of funds that may be used to operate or abandon a well when the licensee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility. Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred as well as annual levies for inactive wells and batteries.

Quebec

To date, Quebec has not implemented a liability management rating program similar to those found in certain of the western provinces. However, the *Mining Act* and the *Regulation respecting Petroleum, Natural gas and Underground Reservoirs* provide that an application for a well drilling licence must be accompanied by a performance guarantee equal to 10% of the estimated cost of operations, which guarantee may not be less than $5,000 or more than $150,000. An application for a well drilling licence must also be submitted with a certified copy of a liability insurance policy in the amount of $1,000,000 covering any damage due to drilling operations or the drilling equipment. Both the performance guarantee and the liability insurance policy must be kept in force until the well is closed permanently in compliance with the *Mining Act* and the *Regulation respecting Petroleum, Natural Gas and Underground Reservoirs*, although the performance guarantee may, in some cases, be released following the cumulative payment of the royalty reaching the amount of the guarantee (for petroleum or natural gas production wells). These rules will however be reviewed and replaced once the *Petroleum Resources Act*, assented in December 2016, comes into force. The date of the coming into force of the *Petroleum Resources Act* has not yet been set and the regulations referred to in said act remains to be drafted and enacted.

Climate Change Regulation

Federal

The Government of Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing GHG emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The federal government ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the federal government replaced its INDC of a 17% reduction target established in the Copenhagen Accord with an NDC of 30% reduction below 2005 levels by 2030.

On April 26, 2007, the Government of Canada released "*Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution*" (the "**Action Plan**") which sets forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "*Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions*" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although the intention was for draft regulations for the implementation of the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the federal government formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

In general, there is uncertainty with regard to the impact of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the Specified Gas Emitters Regulation ("**SGER**"), which imposes GHG limits.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year ("**Regulated Emitters**") are subject to compliance with the CCEMA. On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act*, *2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Alberta Climate Leadership Plan

In November 2015, the Alberta government announced its climate leadership plan (the "**CLP**") and released to the public the climate leadership report to the Minister of Environment and Parks (the "**Report**") that it commissioned from the Climate Change Advisory Plan and on which the CLP is based. The CLP includes four strategies that the government will implement to address climate change: (i) the complete phase-out of coal-fired sources of electricity by 2030: (ii) implementing an

Alberta economy-wide price on GHGs of $30 per tonne; (iii) reducing oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current industry emissions levels of approximately 70 megatonnes per year), with certain exceptions for cogeneration power sources and new upgrading capacity; and (iv) reducing methane emissions from oil and gas activities by 45% by 2025. Uncertainties exist with respect to the implementation of the CLP and the effects that the CLP, including the overall emissions limit, may have on the oil and gas industry.

Adverse impacts to the Corporation's business as a result of comprehensive GHG legislation or regulation, including legislation to implement the CLP and applied to the Corporation's business in Alberta or any jurisdiction in which the Corporation operates, may include, but are not limited to: increased compliance costs; permitting delays; substantial costs to generate or purchase emission credits or allowances adding costs to the products the Corporation produces; and reduced demand for crude oil and certain refined products. Emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis. Required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on the Corporation's business resulting in, among other things, fines, permitting delays, penalties and the suspensions of operations. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to the Corporation.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any additional programs or additional regulations cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

On June 7, 2016, the *Climate Leadership Implementation Act* ("***CLIA***") was passed into law. The CLIA enacted the *Climate Leadership Act* ("**CLA**") to implement a levy on fossil fuels effective as of January 1, 2017 (the "**Levy**"). The Levy applies broadly throughout the fuel supply chain, and is imposed at times which include when fuel is purchased, imported and removed from oil and gas infrastructure. The Levy is imposed at a rate based on the amount of fossil fuels emitted, which translates into a price per volume of fuel. For 2017, the Levy is priced at $20/tonne of greenhouse gas emissions, rising to $30/tonne in 2018. The Government of Alberta recently announced its intention to raise this price to $50/tonne by 2022. Certain exemptions to the Levy are available, although some will only apply for a limited time. Some key exemptions include fuel used in an oil and gas production process prior to 2023, fuel sold for export, fuel used in industrial processes which is not combusted and certain fuel used by first nations and farmers. Further, sites which are already subject to the SGER will be generally be exempt from the Levy, as they are subject to a separate regime. Despite these exemptions, the Levy is expected to increase the cost of doing business in Alberta and may cause a decrease in demand for fossil fuels in the province.

The passing of the CLIA is the first step towards executing the CLP (other legislation is still pending). In addition to enacting the CLA, the CLIA also enacted the *Energy Efficiency Alberta Act*, which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower methane emissions by 45 percent by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of CO_2

equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

In their 2012 Budget, British Columbia announced the government will undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review will cover all aspects of the carbon tax, including revenue neutrality, and will consider the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review last year, British Columbia confirmed it will keep its revenue-neutral carbon tax, the current carbon tax rates and tax base will be maintained, and revenues will continue to be returned through tax reductions.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The Cap and Trade Act sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. The reporting system for large emitters of GHGs has since been streamlined by the *Greenhouse Gas Industrial Reporting and Control Act* (the "**GGIRCA**") and its associated regulations that came into force on January 1, 2016. The GGIRCA sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures, and replaces the Cap and Trade Act.

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80% reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia will soon implement a formal policy to regulate carbon capture and storage projects. Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a Legacy phase that targets a 45% reduction in fugitive and vented emissions by 2025 for facilities built before January 1, 2015, followed by a Transition phase for facilities built between 2015 and 2018 that involves a new offset protocol and a Clean Infrastructure Royalty Credit Program along with other incentives, and finally a Future phase that will implement standards going forward.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20 per cent reduction in GHG emissions from 2006 levels by 2020. The MRGGA and related regulations have not yet been proclaimed in force.

Manitoba

The Government of Manitoba commenced public consultations with respect to the development of a cap and trade system to reduce GHG emissions in 2010. The enactment of *The Climate Change and Emissions Reductions Act* (Manitoba) set emission reduction targets as of December 31, 2012 at six per cent below 1990 emissions and details the commitment of the Government of Manitoba to various initiatives in an effort to reduce GHG emissions. On December 3, 2015, the Government of Manitoba announced Manitoba's Climate Change and Green Energy Action Plan to address climate change and create green jobs. One component of this plan involves cutting GHG emissions by one-third of its 2005 levels by 2030, in part by implementing a cap and trade program for large emitters. Following this announcement, on December 7, 2015, the Government of Manitoba announced that it has signed a memorandum of understanding with both Ontario and Quebec formalizing the intent of all three provinces to link their respective cap-and-trade systems. However, no legislation has been enacted to implement the initiatives outlined in Manitoba's Climate Change and Green Energy Action Plan or the memorandum of understanding.

Quebec

Pursuant to the *Regulation respecting mandatory reporting of certain emissions of contaminants into the atmosphere*, Quebec facilities emitting more than 10,000 tonnes CO2 equivalent of greenhouse gases a year, subject to certain exceptions, must record and report those emissions to the MDDELCC. Pursuant to the Regulation Respecting a Cap-and-trade System for Greenhouse Gas Emission Allowances, certain targeted emitters of greenhouse gas in a quantity equal to or greater than 25,000 metric tonnes CO2 equivalent annually, subject to certain exceptions, are required since 2013 to cover all their greenhouse gas emissions with emission allowances obtained by a combination, as applicable, of free distribution and auction, as well as emissions reduction units from offset projects or recognized compliance units from other jurisdictions. These requirements are related to the Government of Quebec's goal of reducing greenhouse gas emissions in the province by 20% of 1990 emission levels by 2020 and 37.5% by 2030.

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, 345,118,250 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 each of the Toronto Stock Exchange and the Oslo Stock Exchange as reported by sources Questerre believes to be reliable for the periods indicated:

Toronto Stock Exchange

	Price Range (C$)		
	High	Low	Trading Volume
2016			
January	0.20	0.14	366,690
February	0.21	0.15	401,571
March	0.20	0.16	503,851
April	0.21	0.16	1,228,690
May	0.19	0.16	1,595,234
June	0.24	0.17	1,119,705
July	0.20	0.18	566,831
August	0.20	0.16	859,529
September	0.28	0.18	800,173
October	0.66	0.26	5,055,141
November	0.51	0.38	1,645,266
December	1.18	0.45	9,436,712
2017			
January	0.99	0.64	1,870,720
February	0.99	0.68	1,823,421
March (1-24)	0.79	0.57	761,635

Oslo Stock Exchange

	Price Range (NOK)		
	High	Low	Trading Volume
2016			
January	1.22	0.85	16,192,261
February	1.22	0.94	7,636,635
March	1.32	1.07	13,247,421
April	1.37	0.99	13,692,098
May	1.31	1.07	7,324,124
June	1.67	1.08	33,627,520
July	1.31	1.10	18,820,451
August	1.30	1.20	8,155,887
September	1.73	1.16	26,243,517
October	4.53	1.55	324,140,815
November	3.35	2.38	117,615,888
December	9.09	3.00	338,202,488
2017			
January	6.39	4.12	119,963,104
February	6.33	4.30	146,877,365
March (1-24)	4.99	3.64	96,173,450

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, 2016 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	$0.18	4,100,000	June 15, 2016
Warrants	$0.20	13,196,083	July 28, 2016

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.

DIRECTORS AND OFFICERS

The following table sets forth the names and residences of the current 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
Michael R. Binnion 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.
Earl Hickok (2)(5) Director Calgary, Alberta, Canada	Director since June 2014	President, Chief Executive Officer and director of TSO Energy Corporation, a private junior exploration and production company since July 2010. Prior thereto, President, Chief Operating Officer and director of TUSK Energy Corporation.
Alain Sans Cartier (3)(4) Director Quebec City, Quebec, Canada	Director since May 2013	Vice-President, Public Affairs and Strategic Partnership at Quebec Port Authority since November 2012. Prior thereto, Senior Director at Citizen Optimum PR from August 2010 to November 2012.
Dennis F. Sykora (2)(5) Director Calgary, Alberta, Canada	Director since March 2013	Independent businessman. From 2007 to 2014, served as an Executive of High Arctic Energy Services including Executive Vice President, General Counsel and Chief Executive Officer.

Name and Municipality of Residence	Offices Held and Time as Director or Officer	Principal Occupation During the Last Five Years
Bjorn Inge Tonnessen (2)(3)(4)(5) Chairman Oslo, Norway	Director since November 2007	Independent businessman. President and Chief Executive Officer of Spike Exploration, a private Norwegian exploration and production company from June 2012 till June 2016. Prior thereto, Managing Director in Norway and Executive VP, License Management for the Svenska Group from September 2007.
John Brodylo, P. Geol Vice President, Exploration Calgary, Alberta, Canada	Vice President, Exploration since January 2004	Vice President, Exploration of Questerre since January 2004.
Peter Coldham, P. Eng., MBA Vice President, Engineering Calgary, Alberta, Canada	Vice President, Engineering and Operations since December 2005	Vice President, Engineering and Operations of Questerre since December 2005.
Jason D'Silva Chief Financial Officer Calgary, Alberta, Canada	Chief Financial Officer since 2005	Chief Financial Officer of Questerre since 2005.
Rick Tityk Vice President, Land Calgary, Alberta, Canada	Vice President, Land since November 2005	Vice President, Land of Questerre since November 2005.

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.
(3) Corporate Governance and Nominating Committee member.
(4) Compensation Committee member.
(5) Reserve Committee member.
(6) 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 20,226,464 Common Shares or approximately 5.86% of the outstanding Common Shares at the date of this AIF.

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 AIF, or was within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including Questerre), 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.

None of the directors or executive officers of the Corporation (nor any personal holding company of any of such persons), or security holder holding a sufficient number of our securities to affect materially the control of Questerre is, as of the date of this AIF, or has been within the ten years before the date of this AIF, 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 AIF, 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.

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 AIF 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 E and Appendix F attached hereto.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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 company 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, except that, an aggregate of 13.87 million units or 53% of the Flow-Through Placement was subscribed by certain directors and officers of the Corporation, one of whom was the Chief Executive Officer who acquired approximately 13.45 million units of which 9.25 million units or approximately 69% of such securities were vended to independent third parties following closing.

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 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, 2016 other than McDaniel, Questerre's independent qualified reserves evaluator, GLJ Petroleum Consultants, Questerre's independent resource evaluator, and PricewaterhouseCoopers LLP, Questerre's auditor. To Questerre's knowledge, none of the principals of McDaniel or GLJ 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 Professional Accountants, who have prepared an independent auditor's report dated March 24, 2017 in respect of the Corporation's consolidated financial statements as at December 31, 2016 and 2015 and for each of the years ended December 31, 2016 and 2015. 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 property is or was the subject of, during the financial year ended December 31, 2016 nor are there any such proceedings known to the Corporation to be contemplated except as follows:

On June 1, 2011, a joint venture partner filed a statement of claim at the Court of Queen's Bench of Alberta with respect to amounts formally disputed by Questerre. Questerre has filed its statement of defense and counterclaim with respect to this issue. On June 24, 2015, the partner made an application for a summary judgement on the basis that pursuant to the governing agreement, Questerre is obligated to pay these amounts first and dispute later. Pursuant to a judgement issued on December 7, 2015, the Court ruled that Questerre was obligated to pay the amount outstanding with respect to the disputed and undisputed wells totalling $4.72 million and interest of $1.25 million. The amount was paid in March 2015. In November 2016, Questerre received a favorable ruling with respect to its appeal of this summary judgement. In March 2017, Questerre was refunded $5.9 million as a result of this appeal. The joint venture partner has appealed this ruling and a date for this hearing is to be determined. The refund will be recorded in the Company's current assets with an offsetting liability in respect of the potential exposure for these costs primarily relating to drilling two wells in Quebec in 2010. A trial is currently scheduled for late 2018 in respect of the Company's obligations primarily related to these two wells.

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 filed in May 2016 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's discussion and analysis for the year ended December 31, 2016. 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 AIF, 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 Chief Financial Officer 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.

SELECTED ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
bbls/d	barrels per day
API	American Petroleum Institute
NGLs	natural gas liquids

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
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
MMcfe/d	Million cubic feet of natural gas Equivalent converting 1 barrel of oil to six Mcf of natural gas
Mboe	thousand barrels of oil equivalent
M$	thousands of dollars
MMboe	million barrels of oil equivalent
NPV	net present value

In this AIF 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: 1 bbl is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF and in certain documents incorporated by reference into this AIF, 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", "potential", "targeting", "intend", "could", "might", "should", "believe", "prospect", "future", "possible", "can", "speculative", "perhaps" 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 AIF should not be unduly relied upon. These statements speak only as of the date of this AIF or as of the date specified in the documents incorporated by reference into this AIF, as the case may be.

Forward-looking information and statements are included throughout this AIF (and the documents incorporated by reference herein) and include, but are not limited to, statements pertaining to the following:

- Questerre's corporate strategy;
- the scalability and impact of Questerre's projects;
- Questerre's competitive position;
- Questerre's reserves and resources;
- any estimate of present value or future net cash flow;
- drilling inventory, drilling plans and timing of drilling, completion and tie-in of wells;
- plans for facilities and infrastructure construction;
- evaluation of oil shale potential in Jordan;
- assessment of the Utica shale gas discovery in the St. Lawrence Lowlands, Quebec;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- joint venture participation;
- drilling, completion and facilities costs;
- results of various projects, current and anticipated, of Questerre;
- the implementation of processing, transportation and marketing agreements;
- regulatory approvals;
- Questerre's development plans;
- the tax horizon and taxability of Questerre;
- properties with no attributed reserves;
- abandonment and reclamation costs;
- Questerre's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the impact of governmental regulation on Questerre;
- projections of commodity prices and costs;
- expectations regarding the ability to raise capital;
- Questerre's ability to finance future development costs;
- expected royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses including, but not limited to, financial commitments;
- timing and extent of operations, work and appraisal performed by the Company and by Red Leaf;
- capital expenditure programs;
- treatment under current, new and proposed government regulation and fiscal regimes, including those in Quebec;
- the Company's dividend policy;
- potential conflicts of interest; and
- expectations regarding the risk factors faced by Questerre, including mitigation thereof and the potential effects thereof.

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

- general economic conditions 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, NGLs 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;
- 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;
- geopolitical instability;
- availability of financing on acceptable terms;
- competition for, among other things, capital, acquisitions of 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 this AIF and other risk factors identified in other documents incorporated herein by reference.

These factors should not be considered exhaustive. Statements relating to "reserves" and "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described can be profitably produced in the future. With respect to forward-looking statements contained or incorporated by reference in this AIF, Questerre has made assumptions regarding: future exchange rates; energy markets and the price of oil and natural gas; the impact of increasing competition; condition of general economic, commodity 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 environmental and tax laws; 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 AIF and the documents incorporated by reference herein in order to provide readers with a more complete perspective on Questerre's future operations and prospects. Readers are cautioned that this information may not be appropriate for other purposes.

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

NON-GAAP MEASURES

This Annual Information Form uses “netback” which does not have standardized meanings prescribed by generally accepted accounting principles and therefore may not be comparable measures to other companies where similar terminology is used. Netback denotes petroleum and natural gas revenue less royalties, operating expenses and transportation and marketing expenses.

PRESENTATION OF OIL AND GAS INFORMATION

All oil and gas information contained in this AIF 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.

For more information on reserves categories, see Appendix D – *Definitions Used for Reserves Categories*.

APPENDIX A
DISCLOSURE OF RESOURCES DATA

Introduction

Certain terms used herein are defined under the headings "*Introduction*" and "*Presentation of Oil and Gas Information*" in the Annual Information Form and in Appendix D – *Definitions Used for Reserve and Resource Categories* to this Annual Information Form*.* Certain other terms used herein but not defined are defined in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook, as applicable.

Questerre's resources are located in Canada, in the Province of Quebec, and in Jordan. Unless otherwise indicated, all volumes of Questerre's resources presented herein are on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality, and all volumes are presented on a gross basis, meaning Questerre's working interest before deduction of royalties and without including any royalty interests of Questerre. Numbers in the tables presented herein may not total due to rounding.

The estimates of Questerre's resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and variances could be material. With respect to Questerre's discovered resources (including contingent resources), there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to Questerre's undiscovered resources (including prospective resources), there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Estimates of future net revenue, whether calculated without discount or using a discount rate, do not represent fair market value. Please see "*Risk Factors*" in the Annual Information Form to which this Appendix A is attached.

For further information regarding the presentation of Questerre's resource disclosure, please see "*Presentation of Oil and Gas Information*" and "*Selected Abbreviations*" in the Annual Information Form.

St, Lawrence Lowlands, Quebec

Questerre engaged GLJ Petroleum Consultants Ltd. ("**GLJ**") to prepare an independent resource assessment of its 735,910 gross (190,800 net acres) in the St. Lawrence Lowlands, Quebec that have potential for the Upper Utica Shale effective December 31, 2016 in a report dated February 8, 2017 (the "**GLJ Resource Assessment**"). The GLJ Resource Assessment was prepared in accordance with NI 51-101 and the standards contained in the COGE Handbook. The GLJ Resource Assessment did not include any of the Corporation's other properties. All anticipated results disclosed herein were prepared by GLJ, which is an independent qualified reserves evaluator.

GLJ used probabilistic methods to generate low, best and high estimates of total petroleum initially in-place ("**TPIIP**"), both discovered and undiscovered. Recoverable Contingent and Prospective Resources over Questerre's acreage were estimated by analogy and based on available well data over the Quebec Utica and public data from US Utica and Marcellus shale plays. The evaluation consisted of the Upper Utica which includes the Indian Castle and Dolgeville members as well as the Flat Creek. The Flat Creek, the lower most member, was only evaluated to estimate undiscovered petroleum initially-in-place ("**UPIIP**"). No recoverable resources were assigned to the Flat Creek given the lack of test data showing established technology can support commercial development at this time.

The GLJ Resource Assessment is based on the results from several vertical and horizontal wells on the Questerre's acreage that have all encountered pay in the Utica. Test data from these wells in conjunction with offset development and studies of the analogous US Utica supports the prospective commercial development of these resources.

Significant positive factors relevant to the estimate of Questerre's resources include the importation of all natural gas consumed in Quebec creating demand for local production, premium realized pricing due to the transportation costs associated with importing natural gas for consumption, production test data from Questerre's existing wells and the development of the analogous Utica shale in the United States. Significant negative factors include the limited number of wells on Questerre's acreage, lack of a developed service sector providing uncertainty regarding estimates of capital and operating costs, developing hydrocarbon regulations and environmental legislation and the requirement to obtain social acceptability for oil and gas operations.

While Questerre believes it will have sufficient financial capability to fund its share of costs associated with the development program in the GLJ Resource Assessment, it may not have access to the necessary capital when required. Conducting the development program is also dependent on the participation by Questerre's joint venture partners. There is no guarantee that they will elect to participate in the program to the extent required. Questerre retains the right to conduct activities without the operators' participation on an independent operations basis whereby it can fund 100% of the capital costs for certain well operations and facilities in return for net revenue equal to 400% of its capital investment before the operators can elect to either remain in a penalty position or hold a working interest.

Contingent Resources

The TPIIP was determined probabilistically on a permit basis with estimates of 45 to 145 Bcf per square mile for the Upper Utica. This compares favorably to analogous US shale plays with estimates of the Utica in Ohio at between 35 to 85 Bcf per square mile and 25 to 150 Bcf per square mile for the Marcellus shale in Pennsylvania. Of the TPIIP estimated over Questerre's acreage, only land within a 3 mile radius of a successfully tested well was quantified as discovered gas-in-place. Based on this qualification only 16% of the total mapped TPIIP in the Upper Utica was considered discovered Contingent Resource.

The Upper Utica was considered undiscovered for approximately 84% of the total mapped TPIIP. Recovery factors of 18%, 26% and 37% were applied to the low, best and high estimates resource cases respectively.

Summary information regarding contingent resources and net present value of future net revenues from contingent resources are set forth below and are derived, in each case, from the GLJ Resource Assessment. All contingent resources evaluated in the GLJ Resource Assessment were deemed economic at the effective date of December 31, 2016. Contingent resources are in addition to reserves estimated in the GLJ Report.

No Contingent Resources were assigned to Questerre's acreage as of December 31, 2010, the date of the last resource assessment commissioned by Questerre in respect of this property completed by Netherland, Sewell & Associates, Inc., as a result of the high uncertainty of economic potential at that time.

Questerre's average working interest in its gross best estimate Contingent Resources is 25.9%.

A range of contingent resources estimates (low, best and high) were prepared by GLJ. See notes 5 to 7 of the tables below for a description of low estimate, best estimate and high estimate.

The GLJ Resources Assessment estimated gross risked contingent resources with a project maturity subclass of development on hold of 18.6 million boe (low estimate) to 50.0 million boe (high estimate), with a best estimate of 30.4 million boe.

The GLJ Resources Assessment estimated gross risked contingent resources with a project maturity subclass of development unclarified of 8.9 million boe (low estimate) to 23.8 million boe (high estimate), with a best estimate of 14.6 million boe.

An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary Of Oil And Gas Risked Resources

Resources Category		Shale Gas		Oil Equivalent				
		Company Gross MMcf	Company Net MMcf	Company Gross Mboe	Company Net Mboe	Chance of Development %	Chance of Discovery %	Chance of Commerciality %
Contingent Resources								
Low Estimate - On Hold								
	Becancour / Ste. Sophie-de-Levrard	53,020	57,221	8,837	9,537	70	100	70
	La Visitation-de-Yamaska	0	0	0	0	-	-	
	St. David	0	0	0	0	-	-	
	St. Edouard-de-Lotbiniere	58,520	62,423	9,753	10,404	70	100	70
	St. Francois-du-Lac / Pierreville	0	0	0	0	-	-	
	St. Louis	0	0	0	0	-	-	
	Utica Prospective Resources	0	0	0	0	-	-	
Total: Low Estimate - On Hold		111,540	119,644	18,590	19,941			
Best Estimate - On Hold								
	Becancour / Ste. Sophie-de-Levrard	86,760	93,559	14,460	15,593	70	100	70
	La Visitation-de-Yamaska	0	0	0	0	-	-	
	St. David	0	0	0	0	-	-	
	St. Edouard-de-Lotbiniere	95,760	102,119	15,960	17,020	70	100	70
	St. Francois-du-Lac / Pierreville	0	0	0	0	-	-	
	St. Louis	0	0	0	0	-	-	
	Utica Prospective Resources	0	0	0	0	-	-	
Total: Best Estimate - On Hold		182,520	195,677	30,420	32,613			
High Estimate - On Hold								
	Becancour / Ste. Sophie-de-Levrard	142,560	153,588	23,760	25,598	70	100	70
	La Visitation-de-Yamaska	0	0	0	0	-	-	
	St. David	0	0	0	0	-	-	
	St. Edouard-de-Lotbiniere	157,349	167,695	26,225	27,949	70	100	70
	St. Francois-du-Lac / Pierreville	0	0	0	0	-	-	
	St. Louis	0	0	0	0	-	-	
	Utica Prospective Resources	0	0	0	0	-	-	
Total: High Estimate - On Hold		299,909	321,284	49,985	53,547			

Summary Of Oil And Gas Risked Resources

Resources Category		Shale Gas Company Gross MMcf	Shale Gas Company Net MMcf	Oil Equivalent Company Gross Mboe	Oil Equivalent Company Net Mboe	Chance of Development %	Chance of Discovery %	Chance of Commerciality %
Contingent Resources								
Low Estimate - Unclarified								
	Becancour / Ste. Sophie-de-Levrard	0	0	0	0	-	-	
	La Visitation-de-Yamaska	28,737	30,646	4,790	5,108	25	100	25
	St. David	11,495	12,255	1,916	2,043	10	100	10
	St. Edouard-de-Lotbiniere	0	0	0	0	-	-	
	St. Francois-du-Lac / Pierreville	6,688	5,996	1,115	999	10	100	10
	St. Louis	6,688	5,996	1,115	999	10	100	10
	Utica Prospective Resources	0	0	0	0	-	-	
Total: Low Estimate - Unclarified		53,608	54,893	8,935	9,149			
Best Estimate - Unclarified								
	Becancour / Ste. Sophie-de-Levrard	0	0	0	0	-	-	
	La Visitation-de-Yamaska	47,025	50,140	7,837	8,357	25	100	25
	St. David	18,810	20,051	3,135	3,342	10	100	10
	St. Edouard-de-Lotbiniere	0	0	0	0	-	-	
	St. Francois-du-Lac / Pierreville	10,944	9,809	1,824	1,635	10	100	10
	St. Louis	10,944	9,809	1,824	1,635	10	100	10
	Utica Prospective Resources	0	0	0	0	-	-	
Total: Best Estimate - Unclarified		87,723	89,809	14,620	14,968			
High Estimate - Unclarified								
	Becancour / Ste. Sophie-de-Levrard	0	0	0	0	-	-	
	La Visitation-de-Yamaska	76,698	81,731	12,783	13,622	25	100	25
	St. David	30,469	32,457	5,078	5,409	10	100	10
	St. Edouard-de-Lotbiniere	0	0	0	0	-	-	
	St. Francois-du-Lac / Pierreville	17,878	16,012	2,980	2,669	10	100	10
	St. Louis	17,759	15,906	2,960	2,651	10	100	10
	Utica Prospective Resources	0	0	0	0	-	-	
Total: High Estimate - Unclarified		142,804	146,106	23,801	24,351			

Risked Summary Net Present Values of Future Net Revenue

Resources Category		Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)					Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
		M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	$/boe	$/Mcfe
Contingent Resources													
Low Estimate - On Hold													
	Becancour / Ste. Sophie-de-Levrard	214580	123987	78307	52397	36425	214580	123987	78307	52397	36425	8.21	1.37
	La Visitation-de-Yamaska	0	0	0	0	0	0	0	0	0	0	0	0
	St. David	0	0	0	0	0	0	0	0	0	0	0	0
	St. Edouard-de-Lotbiniere	231,705	133,336	83,779	55,718	38,460	231,705	133,336	83,779	55,718	38,460	8.05	1.34
	St. Francois-du-Lac / Pierreville	0	0	0	0	0	0	0	0	0	0	0	0
	St. Louis	0	0	0	0	0	0	0	0	0	0	0	0
	Utica Prospective Resources	0	0	0	0	0	0	0	0	0	0	0	0
Total: Low Estimate - On Hold		446,285	257,323	162,086	108,116	74,885	446,285	257,323	162,086	108,116	74,885		
Best Estimate - On Hold													
	Becancour / Ste. Sophie-de-Levrard	438486	238497	149586	101917	73113	438486	238497	149586	101917	73113	9.59	1.6
	La Visitation-de-Yamaska	0	0	0	0	0	0	0	0	0	0	0	0
	St. David	0	0	0	0	0	0	0	0	0	0	0	0
	St. Edouard-de-Lotbiniere	475,817	258,269	161,560	109,757	78,497	475,817	258,269	161,560	109,757	78,497	9.49	1.58
	St. Francois-du-Lac / Pierreville	0	0	0	0	0	0	0	0	0	0	0	0
	St. Louis	0	0	0	0	0	0	0	0	0	0	0	0
	Utica Prospective Resources	0	0	0	0	0	0	0	0	0	0	0	0
Total: Best Estimate - On Hold		914,302	496,766	311,145	211,674	151,610	914,302	496,766	311,145	211,674	151,610		
High Estimate - On Hold													
	Becancour / Ste. Sophie-de-Levrard	839251	426640	264053	180986	131592	839251	426640	264053	180986	131592	10.32	1.72
	La Visitation-de-Yamaska	0	0	0	0	0	0	0	0	0	0	0	0
	St. David	0	0	0	0	0	0	0	0	0	0	0	0
	St. Edouard-de-Lotbiniere	913,000	463,572	286,473	196,041	142,310	913,000	463,572	286,473	196,041	142,310	10.25	1.71
	St. Francois-du-Lac / Pierreville	0	0	0	0	0	0	0	0	0	0	0	0
	St. Louis	0	0	0	0	0	0	0	0	0	0	0	0
	Utica Prospective Resources	0	0	0	0	0	0	0	0	0	0	0	0
Total: High Estimate - On Hold		1,752,251	890,213	550,526	377,027	273,901	1,752,251	890,213	550,526	377,027	273,901		

Risked Summary Net Present Values of Future Net Revenue

		Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)					Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
Resource Category		0% M$	5% M$	10% M$	15% M$	20% M$	0% M$	5% M$	10% M$	15% M$	20% M$	$/boe	$/Mcfe
Contingent Resources													
Low Estimate - Unclarified													
	Becancour / Ste. Sophie-de-Levrard	0	0	0	0	0	0	0	0	0	0	0	0
	La Visitation-de-Yamaska	121,737	62,579	35,381	21,312	13,405	121,737	62,579	35,381	21,312	13,405	6.93	1.15
	St. David	51,446	24,067	12,473	6,930	4,043	51,446	24,067	12,473	6,930	4,043	6.11	1.02
	St. Edouard-de-Lotbiniere	0	0	0	0	0	0	0	0	0	0	0	0
	St. Francois-du-Lac / Pierreville	20,910	10,743	5,986	3,517	2,135	20,910	10,743	5,986	3,517	2,135	5.99	1
	St. Louis	21,905	10,254	5,237	2,836	1,597	21,905	10,254	5,237	2,836	1,597	5.24	0.87
	Utica Prospective Resources	0	0	0	0	0	0	0	0	0	0	0	0
Total: Low Estimate - Unclarified		215,999	107,643	59,078	34,595	21,180	215,999	107,643	59,078	34,595	21,180		
Best Estimate - Unclarified													
	Becancour / Ste. Sophie-de-Levrard	0	0	0	0	0	0	0	0	0	0	0	0
	La Visitation-de-Yamaska	248,139	120,012	67,328	41,253	26,747	248,139	120,012	67,328	41,253	26,747	8.06	1.34
	St. David	104,184	45,750	23,457	13,205	7,901	104,184	45,750	23,457	13,205	7,901	7.02	1.17
	St. Edouard-de-Lotbiniere	0	0	0	0	0	0	0	0	0	0	0	0
	St. Francois-du-Lac / Pierreville	44,487	21,858	12,326	7,554	4,884	44,487	21,858	12,326	7,554	4,884	7.54	1.26
	St. Louis	46,439	20,749	10,694	6,018	3,588	46,439	20,749	10,694	6,018	3,588	6.54	1.09
	Utica Prospective Resources	0	0	0	0	0	0	0	0	0	0	0	0
Total: Best Estimate - Unclarified		443,248	208,369	113,805	68,030	43,119	443,248	208,369	113,805	68,030	43,119		
High Estimate - Unclarified													
	Becancour / Ste. Sophie-de-Levrard	0	0	0	0	0	0	0	0	0	0	0	0
	La Visitation-de-Yamaska	467,260	212,000	116,980	71,759	46,904	467,260	212,000	116,980	71,759	46,904	8.59	1.43
	St. David	193,937	80,648	40,779	23,003	13,882	193,937	80,648	40,779	23,003	13,882	7.54	1.26
	St. Edouard-de-Lotbiniere	0	0	0	0	0	0	0	0	0	0	0	0
	St. Francois-du-Lac / Pierreville	86,057	39,711	22,161	13,711	9,023	86,057	39,711	22,161	13,711	9,023	8.3	1.38
	St. Louis	89,076	37,635	19,224	10,922	6,627	89,076	37,635	19,224	10,922	6,627	7.25	1.21
	Utica Prospective Resources	0	0	0	0	0	0	0	0	0	0	0	0
Total: High Estimate - Unclarified		836,330	369,994	199,143	119,396	76,437	836,330	369,994	199,143	119,396	76,437		

Notes:

1) Contingent resources are defined in the COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Questerre will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. The risked net present value of the future net revenue from the contingent resources does not represent the fair market value of the contingent resources. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

2) GLJ prepared the estimates of contingent resources shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table.

3) "Gross” contingent resources are Questerre's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Questerre. "Net” contingent resources are Questerre's working interest (operating or non-operating) share after deduction of royalty obligations, plus Questerre's royalty interests in contingent resources.

4) The risked net present value of future net revenue attributable to the contingent resources does not represent the fair market value of the contingent resources. Estimated abandonment and reclamation costs have been included in the evaluation.

5) Low Estimate Contingent Resources are 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 (P90) that the quantities actually recovered will equal or exceed the low estimate.

6) Best Estimate Contingent Resources are 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 (P50) that the quantities actually recovered will equal or exceed the best estimate.

7) High Estimate Contingent Resources are 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 (P10) that the quantities actually recovered will equal or exceed the high estimate.

8) The Chance of Development (CoDev) is the estimated probability that, once discovered, a known accumulation will be commercially developed. Five factors have been considered in determining the CoDev as follows:

- CoDev = Ps (Economic Factor) × Ps (Technology Factor) × Ps (Development Plan Factor) ×Ps (Development Timeframe Factor) × Ps (Other Contingency Factor) wherein
- Ps is the probability of success
- Economic Factor – For reserves to be assessed, a project must be economic. With respect to contingent resources, this factor captures uncertainty in the assessment of economic status principally due to uncertainty in cost estimates and marketing options. Economic viability uncertainty due to technology is more aptly captured with the Technology Factor. The Economic Factor will be 1 for reserves and will often be 1 for development pending projects and for projects with a development study or pre-development study with a robust rate of return. A robust rate of return means that the project retains economic status with variation in costs and/or marketing plans over the expected range of outcomes for these variables.
- Technology Factor - For reserves to be assessed, a project must utilize established technology. With respect to contingent resources, this factor captures the uncertainty in the viability of the proposed technology for the subject reservoir, namely, the uncertainty associated with technology under development. By definition, technology under development is a recovery process or process improvement that has been determined to be technically viable via field test and is being field tested further to determine its economic viability in the subject reservoir. The Technology Factor will be 1 for reserves and for established technology. For technology under development, this factor will consider different risks associated with technologies being developed at the scale of the well versus the scale of a project and technologies which are being modified or extended for the subject reservoir versus new emerging technologies which have not previously been applied in any commercial application. The risk assessment will also consider the quality and sufficiency of the test data available, the ability to reliably scale such data and the ability to extrapolate results in time.
- Development Plan Factor – For reserves to be assessed, a project must have a detailed development plan. With respect to contingent resources, this factor captures the uncertainty in the project evaluation scenario. The Development Plan Factor will be 1 for reserves and high, approaching 1, for development pending projects. This factor will consider development plan detail variations including the degree of delineation, reservoir specific development and operating strategy detail (technology decision, well layouts (spacing and pad locations), completion strategy, start-up strategy, water source and disposal, other infrastructure, facility design, marketing plans etc) and the quality of the cost estimates as provided by the developer.
- Development Timeframe Factor – In the case of major projects, for reserves to be assessed, first major capital spending must be initiated within 5 years of the effective date. The Development Timeframe Factor will be 1 for reserves and will often be 1 for development pending projects provided the project is planned on-stream based on the same criteria used in the assessment of reserves. With respect to contingent resources, the factor will approach 1 for projects planned on-stream with a timeframe slightly longer than the limiting reserves criteria.
- Other Contingency Factor – For reserves to be assessed, all contingencies must be eliminated. With respect to contingent resources, this factor captures major contingencies, usually beyond the control of the operator, other than those captured by economic status, technology status, project evaluation scenario status and the development timeframe. The Other Contingency Factor will be 1 for reserves and for development pending projects and less than 1 for on hold. Provided all contingencies have been identified and their resolution is reasonably certain, this factor would also be 1 for development unclarified projects.
- These factors may be inter-related (dependent) and care has been taken to ensure that risks are appropriately accounted.

9) Contingent resources for the Lowlands have been estimated based the results from several vertical and horizontal wells on the Company's acreage that have all encountered pay in the Utica. Test data from these wells in conjunction with offset development and studies of analogous US Utica supports the prospective commercial development on these resources. The estimated unrisked cost to bring these contingent resources on commercial production is $809.28 million and the expected timeline is between 2 and 11 years. The specific contingencies for these resources are the passage of applicable hydrocarbon and environmental legislation, regulations, local acceptability, firm development plans, detailed cost estimates and corporate approvals and sanctioning.

10) In Canada, GLJ has estimated an aggregate of risked on hold best estimate contingent resources of 35.75 million boe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $168 million with an expected timeline of 2 to 4 years.

    Becancour / Ste. Sophie-de-Levrard - Based on contingencies related to the passage of applicable hydrocarbon and environmental legislation, regulations, local acceptability, firm development plans, detailed cost estimates and corporate approvals and sanctioning GLJ has estimated risked development on hold best estimate contingent resources at 18.67 million boe and the risked estimated cost to bring these resources on commercial production is $79.3 million. The expected timeline is 2 to 4 years.

    St. Edouard-de-Lotbiniere - Based on contingencies related to the passage of applicable hydrocarbon and environmental legislation, regulations, local acceptability and firm development plans, detailed cost estimates and corporate approvals and sanctioning GLJ has estimated risked development on hold best estimate contingent resources at 17.08 million boe and the risked estimated cost to bring these resources on commercial production is $88.7 million. The expected timeline is 1 to 4 years.

11) In Canada, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 16.48 million boe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $83.83 million with an expected timeline of 3 to 8 years.

La Visitation-de-Yamaska - Based on contingencies related to the passage of applicable hydrocarbon and environmental legislation, regulations, local acceptability, and additional risk associated with securing social license to operate, firm development plans, detailed cost estimates and corporate approvals and sanctioning GLJ has estimated risked development unclarified best estimate contingent resources at 9.17 million boe and the risked estimated cost to bring these resources on commercial production is $44.83 million. The expected timeline is 3 to 7 years.

St, David - Based on contingencies related to the passage of applicable hydrocarbon and environmental legislation, regulations, local acceptability, and additional risk associated with securing social license to operate, firm development plans, detailed cost estimates and corporate approvals and sanctioning GLJ has estimated risked development on hold best estimate contingent resources at 3.67 million boe and the risked estimated cost to bring these resources on commercial production is $18.15 million. The expected timeline is 5 to 9 years.

St. Francois-du-Lac / Pierreville - Based on contingencies related to the passage of applicable hydrocarbon and environmental legislation, regulations, local acceptability, and additional risk associated with securing social license to operate, firm development plans, detailed cost estimates and corporate approvals and sanctioning GLJ has estimated risked development on hold best estimate contingent resources at 1.82 million boe and the risked estimated cost to bring these resources on commercial production is $10.29 million. The expected timeline is 3 to 6 years.

St. Louis - Based on contingencies related to the passage of applicable hydrocarbon and environmental legislation, regulations, local acceptability, and additional risk associated with securing social license to operate, firm development plans, detailed cost estimates and corporate approvals and sanctioning GLJ has estimated risked development on hold best estimate contingent resources at 1.82 million boe and the risked estimated cost to bring these resources on commercial production is $10.56 million. The expected timeline is 5 to 8 years.

GLJ Petroleum Consultants
Summary of Natural Gas Price Forecasts
January 1, 2017

	NYMEX Henry Hub Near Month Contract		Midwest Price at Chicago	AECO/NIT Spot	Alliance Transfer Pool Spot	Alberta Plant Gate			Saskatchewan Plant Gate			British Columbia		Sulphur	Alberta Sulphur
						Spot									
Year	Constant 2017 $ USD/MMBtu	Then Current USD/MMBtu	Then Current USD/MMBtu	Then Current CAD/MMBtu	Then Current CAD/MMBtu	Constant 2017 $ CAD/MMBtu	Then Current CAD/MMBtu	ARP CAD/MMBtu	SaskEnergy CAD/MMBtu	Spot CAD/MMBtu	Sumas Spot USD/MMBtu	Westcoast Station 2 CAD/MMBtu	Spot Plant Gate CAD/MMBtu	FOB Vancouver USD/lt	at Plant Gate CAD/lt
2016	2.59	2.55	2.48	2.19	2.31	1.98	1.95	1.95	2.22	2.09	2.18	1.78	1.60	82.84	60.06
2017 Q1	3.70	3.70	3.85	3.55	3.55	3.30	3.30	3.30	3.40	3.45	3.45	2.95	2.78	80.00	56.67
2017 Q2	3.55	3.55	3.55	3.41	3.41	3.16	3.16	3.16	3.26	3.31	2.75	2.91	2.73	80.00	56.67
2017 Q3	3.55	3.55	3.55	3.41	3.41	3.16	3.16	3.16	3.26	3.31	2.95	2.91	2.73	90.00	70.00
2017 Q4	3.60	3.60	3.65	3.46	3.46	3.20	3.20	3.20	3.30	3.36	3.40	2.96	2.78	90.00	70.00
2017 Full Year	3.60	3.60	3.65	3.46	3.46	3.20	3.20	3.20	3.30	3.36	3.14	2.93	2.76	85.00	63.33
2018	3.14	3.20	3.25	3.10	3.10	2.79	2.85	2.85	2.95	3.00	2.80	2.70	2.52	100.00	79.03
2019	3.27	3.40	3.45	3.27	3.27	2.91	3.02	3.02	3.12	3.17	3.00	2.97	2.80	102.00	77.50
2020	3.39	3.60	3.65	3.49	3.49	3.05	3.24	3.24	3.34	3.39	3.30	3.19	3.01	104.04	76.11
2021	3.51	3.80	3.85	3.67	3.67	3.15	3.41	3.41	3.51	3.57	3.60	3.37	3.19	106.12	74.85
2022	3.62	4.00	4.05	3.86	3.86	3.26	3.60	3.60	3.70	3.76	3.80	3.56	3.38	108.24	77.34
2023	3.73	4.20	4.25	4.05	4.05	3.37	3.79	3.79	3.89	3.95	4.00	3.75	3.57	110.41	79.89
2024	3.75	4.31	4.36	4.16	4.16	3.39	3.90	3.90	4.00	4.06	4.11	3.86	3.68	112.62	82.49
2025	3.75	4.39	4.44	4.24	4.24	3.39	3.97	3.97	4.07	4.14	4.19	3.94	3.76	114.87	85.14
2026	3.75	4.48	4.53	4.32	4.32	3.40	4.06	4.06	4.16	4.22	4.28	4.02	3.84	117.17	87.85
2027+	3.75	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	3.40	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
AECO/NIT Spot refers to the same-day spot price averaged over the period.

Contingent resources can be sub-classified based on their project maturity sub-class which help identify a project's change of commerciality. The project maturity subclasses for contingent resources are "development pending", "development on hold", "development unclarified" or "development not viable", all as defined in the COGE Handbook. "Development pending" is when resolution of the final conditions for development is being actively pursued (high chance of development). "Development on hold" is when there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. “Development unclarified” is when the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties. “Development not viable” is when no further data acquisition or evaluation is currently planned and hence there is a low chance of development.

Those areas classified as development on hold are primarily contingent on the passage of applicable hydrocarbon and environmental legislation and regulations as well as local acceptability. Remaining areas classified as development unclarified have additional contingency or risk associated with securing social license to operate and are thereby a lower priority for development. Additional contingencies include firm development plans, detailed cost estimates and corporate approvals and sanctioning. There is no certainty that any portion of the Contingent Resources will be economic to develop. Though pilot horizontal development plans have been proposed, the project evaluation scenario for the Contingent Resources is not sufficiently defined to make an investment decision to proceed to development.

Contingent Resources are evaluated based on the same fiscal conditions used in the assessment of reserves, and as such, are forecasted to be economic. Contingent Resource values are estimated on the basis of established technology, namely multistage hydraulic fracturing recovery technologies that are widely used in the development of shale gas plays including in the Montney in Canada and the Utica formation in Ohio.

Prospective Resources

Summary information regarding prospective resources and net present value of future net revenues from prospective resources are set forth below and are derived, in each case, from the GLJ Resources Assessment. The GLJ Resources Assessment was prepared in accordance with COGEH and NI-51-101 by GLJ, an independent qualified reserve evaluator. All prospective resources evaluated in the GLJ Resources Assessment were deemed economic at the effective date of December 31, 2016. Prospective resources are in addition to reserves estimated in the GLJ Report.

The Upper Utica was considered undiscovered for approximately 84% of the total mapped TPIIP. Recovery factors of 19%, 27% and 40% were applied to the low, best and high estimates resource cases respectively.

A range of prospective resources estimates (low, best and high) were prepared by GLJ. See notes 6 to 8 of the tables below for a description of low estimate, best estimate and high estimate.

The GLJ Resources Assessment estimated gross risked prospective resources of 87 million boe (low estimate) to 238 million boe (high estimate), with a best estimate of 143 million boe.

The chance of commerciality for Prospective Resources is equal to the product of the chance of discovery and the chance of development. “Chance of discovery” is the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. “Chance of development” is the estimated probability that, once discovered, a known accumulation will be commercially developed. Based on contingencies related to the passage of applicable hydrocarbon and environmental legislation, regulations , local acceptability , and additional risk associated with securing social license to operate, firm development plans, detailed cost estimates and corporate approvals GLJ estimated the Chance of Development at 19 percent. Proximity to extensional and compressional-related fault systems presents risk of structuring resulting in leak off and reduced pressures in some prospective regions, additionally, lack of delineation data provides reservoir risk associated with uncertainty regarding reservoir quality and rock mechanics amicable to hydraulic fracturing. Therefore, GLJ has estimated the Chance of Discovery at 81 percent. The corresponding chance of commerciality is 15 percent. This also takes into account Questerre’s working interest and operatorship of its assets as Questerre is subject to the priorities of working interest partners for such assets. Production and development forecasts were not completed by GLJ as part of the prospective resources evaluation.

The following table sets forth Questerre's best estimate risked prospective resources by product type at December 31, 2016:

Summary Of Oil And Gas Risked Resources

	Shale Gas		Oil Equivalent				
Resources Category	Company Gross MMcf	Company Net MMcf	Company Gross Mboe	Company Net Mboe	Chance of Development %	Chance of Discovery %	Chance of Commerciality %
Prospective Resources							
Low Estimate - Prospect	519,459	518,737	86,577	86,456	19	81	15
Best Estimate - Prospect	855,691	854,501	142,615	142,417	19	81	15
High Estimate - Prospect	1,426,152	1,424,168	237,692	237,361	19	81	15

Notes:

1) Prospective resources are defined in the COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from unknown accumulations by application of future development projects. Prospective resources have both an associated chance of discovery (CoDis) and a chance of development (CoDev). There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources or that Questerre will produce any portion of the volumes currently classified as prospective resources. The estimates of prospective resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. The risked net present value of the future net revenue from the prospective resources does not represent the fair market value of the prospective resources. Actual prospective resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

2) GLJ prepared the estimates of prospective resources shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table.

3) The forecast price and cost assumptions utilized in the year-end 2016 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See "GLJ December 31, 2016 Forecast Prices" in this AIF.

4) "Gross" prospective resources are Questerre's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company. "Net" prospective resources are Questerre's working interest (operating or non-operating) share after deduction of royalty obligations, plus Questerre's royalty interests in prospective resources.

5) The risked net present value of future net revenue attributable to the prospective resources does not represent the fair market value of the prospective resources. Estimated abandonment and reclamation costs have been included in the evaluation.

6) The Low Estimate Prospective Resources is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual net remaining quantities recovered will exceed the low estimate of 86 million boe. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

7) The Best Estimate Prospective Resources is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual net remaining quantities recovered will be greater or less than the best estimate of 142 million. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

8) The High Estimate Prospective Resources is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual net remaining quantities recovered will exceed the high estimate of 237 million

boe. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

9) The chance of commerciality is defined as the product of the chance of discovery and the chance of development. Chance of discovery is defined in COGEH as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. Chance of development is defined as the estimated probability that, once discovered, a known accumulation will be commercially developed.

Jordan

In October 2016, Questerre commissioned an independent assessment of its oil shale resources (the "**Jordan Resource Assessment**") in the Hashemite Kingdom of Jordan ("**Jordan**"). The Jordan Resource Assessment was conducted by Millcreek Mining Group ("**Millcreek**"), an independent qualified reserves evaluator, as defined by NI 51-101 with an effective date of September 30, 2016. The Jordan Resource Assessment was prepared in accordance with NI 51-101 and the standards contained in the COGE Handbook.

The Jordan Resource Assessment covers an area of over 380 square km and has been categorized, for the purposes of the Jordan Resource Assessment into three areas referred to Blocks A, B and C separated by two highway and infrastructure corridors. Questerre holds a 100% interest in the acreage and resources. The Jordan Resource Assessment did not include any of the Corporation's other properties. All anticipated results disclosed herein were prepared by Millcreek, which is an independent qualified reserves evaluator. Millcreek used probalistic methods to generate high, best and low estimates of resource volumes.

Questerre is in the process of completing a conceptual study, however, at this time, given the preliminary nature of the Jordan Resource Assessment, it does not contain any estimates regarding the timing or cost to obtain commercial development nor has Questerre finalized the specific recovery technology to be used. Questerre is conducting an economic feasibility analysis, which involves assessing multiple retorting processes, including two processes that have been proven at commercial scale. Also under evaluation is the Eco-Shale process. In conjunction with the assessment of retorting processes, Questerre has commissioned and finalized three engineering studies for the mining, preparation of ore and upgrading of the produced oil and other products. Two additional studies for marketing the finished products and infrastructure including utilities are scheduled for completion in 2017. Questerre anticipates incorporating the results from these studies in a subsequent update of the Jordan Resource Assessment.

The oil shale deposits on Questerre's acreage occur as kerogen-rich beds within the marine chalky limestones and marls of the Muwaqqar Chalk-Marl ("**MCM**") Formation. The Jordan Resource Assessment is based on the Modified Fischer Assay ("**MFA**") data from over 40 core holes, including 35 drilled by the Natural Resources Authority ("**NRA**") and 5 drilled by Questerre in the last three years. The database utilized consists of over 1,900 MFA determinations ranging from 0.19 gallons per ton ("gpt") to 49.49 gpt.

The analytical MFA data suggests that the MCM oil shale is a continuous package with an Upper Lean horizon ("**ULH**") and a Lower Rich horizon ("**LRH**"). Determination between the ULH and LRH is based on assay, using 15 gpt as the minimum grade for the LRH. The ULH has an average thickness of 25.36m with a weighted average oil shale grade of 12.5 gpt. The LRH sits directly below the upper lean horizon with an average thickness of 40.68m. Weighted average grade for the LRH is 22.78 gpt. Both oil shale horizons are continuous throughout the area though based on current drilling, the oil shale horizons appear to pinch out along the southern margins of Blocks A and C.

The petroleum volumes within the area that resulted from this estimation process were classified as Discovered Petroleum Initially in Place ("**DPIIP**") and Undiscovered Petroleum Initially in Place ("**UPIIP**"), in accordance with the criteria of the COGE Handbook. DPIIP resources were further differentiated as Low, Best, and High based upon a statistical analysis of the thickness and grade data. It was determined that a radius of 1,000m from a core hole could satisfactorily be used for quantifying a Low resource estimate. Radii of 2,000m and 4,000m from a core hole were also determined for quantifying Best and High resource estimates, respectively. Resources classified as Undiscovered have not been assigned any levels of confidence. DPIIP and UPIIP are the most specific assignable categories of resources at this time given the preliminary nature of the Jordan Resource Assessment, the nature of recovery of the hydrocarbons by means of mining and that a program of work to determine commercial viability using established technology has not yet been completed.

Discovered and Undiscovered PIIP Estimate (MMbbls) as at October 1, 2016

Parcel	Strata	Low	Best	High	Undiscovered
Block A	ULH	26	65	86	1
	LRH	821	2,024	2,708	27
Block B	ULH	1,301	2,119	3,123	595
	LRH	1,537	2,503	3,689	703
Block C	ULH	146	413	582	24
	LRH	1,806	5,116	7,222	301
Total		**5,636**	**12,240**	**17,410**	**1,651**

The Best Estimate of the DPIIP is approximately 12.2 billion barrels of synthetic crude oil at an average grade of 20.12 gpt. Millcreek has been involved with conceptual mine planning to produce oil shale feedstock to support a surface retorting/processing facility capable of producing 20,000 bbl/d of synthetic crude oil. The purpose of the conceptual mine planning was to develop preliminary mining costs and identify a potential area(s) favorable to mine development. The mine planning considered all regions within the area where the LRH can be mined at less than a 2:1 volumetric ratio of overburden to ore, and considers maximizing ore grade, location to main road and other infrastructure, and minimizing the total mining cost per barrel. The tables below present the resource quantities and their classification that occur within the 2:1 volumetric ratio of overburden to ore, favorable to surface mining. Best Estimate for the LRH identifies 7.8 billion barrels with an average grade of 22.66 gpt.

Discovered and Undiscovered PIIP Estimate (MMbbls) within a 2:1 Volumetric Strip Ratio as at October 1, 2016

Parcel	Strata	Low	Best	High	Undiscovered
A1	ULH	19	48	54	-
	LRH	692	1,759	1,977	-
B1	ULH	232	328	331	-
	LRH	896	1,267	1,280	-
B2	ULH	-	98	164	-
	LRH	-	148	247	-
C1	ULH	148	387	534	34
	LRH	1,763	4,610	6,373	407
Total		**3,750**	**8,645**	**10,960**	**441**

APPENDIX B
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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016 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.

3. 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).

4. 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.

5. The following table shows the net present value of 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 for the year ended December 31, 2016 and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

		Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
February 23, 2017	Canada	-	155,591	-	155,591

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

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the preparation date.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd. Per: *Signed "P.A. Welch"*
2200, 255 - 5th Avenue SW
Calgary, Alberta T2P 3G6

P.A Welch, P.Eng.
President

Calgary, Alberta
February 23, 2017

APPENDIX B
FORM 51-101F2
REPORT ON RESOURCE 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 contingent resources data and prospective resources data as at December 31, 2016. The contingent resources data and prospective resources data are risked estimates of volume of contingent resources and prospective resources and related risked net present value of future net revenue as at December 31, 2016, estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the contingent resources data and prospective resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data and prospective resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources and prospective resources (before deduction of income taxes) attributed to contingent resources and prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data and prospective resources data that we have evaluated and reported on to the Company's management/board of directors:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Mboe)
Development On Hold Contingent Resources	GLJ Petroleum Consultants	December 31, 2016	Canada	35,751
Development Unclarified Contingent Resources	GLJ Petroleum Consultants	December 31, 2016	Canada	16,486
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2016	Canada	156,892

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

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. Because the contingent resources data and prospective resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 17, 2017

"Originally Signed By"

Chad P. Lemke, P. Eng.
Manager, Engineering

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

Management of Questerre Energy Corporation (the "**Company**") is 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, and includes contingent resources data and prospective resources data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data, contingent resources data and prospective resources data. The reports of the independent qualified reserves evaluators is presented above.

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 evaluators;

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

(c) reviewed the reserves data, contingent resource data and prospective resources data with management and the independent qualified reserves evaluators.

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 recommendation of the Reserve Committee, approved

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

(e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data, contingent resources data and prospective resources data; and

(f) 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.

(signed) *"Michael Binnion"*	(signed) *"Peter Coldham"*
Michael Binnion President and Chief Executive Officer	Peter Coldham Vice President, Engineering
(signed) *"Bjorn Inge Tonnessen"*	(signed) *"Earl Hickok"*
Bjorn Inge Tonnessen Director	Earl Hickok Director

March 24, 2017

APPENDIX D
DEFINITIONS USED FOR RESERVE AND RESOURCE CATEGORIES

The following reserves definitions are set out by the Canadian Securities Administrators in CSA Staff Notice 51-324 and are derived from Section 5 of Volume 1 of the COGE Handbook (Second Edition, September 1, 2007). Readers should consult a current edition of the COGE Handbook for updates and for additional explanation and guidance.

Reserve Categories

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

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

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

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

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

(c) 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:

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

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

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

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

Resource Definitions

Resources encompasses all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including Discovered and Undiscovered (recoverable and unrecoverable) plus quantities already produced. "Total resources" is equivalent to "Total Petroleum Initially In Place".

Resources are classified in the following categories:

Total Petroleum Initially In Place ("**TPIIP**") is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.

Discovered Petroleum Initially In Place ("**DPIIP**") is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and Contingent Resources; the remainder is unrecoverable.

Undiscovered Petroleum Initially In Place ("**UPIIP**") is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources" and the remainder as "unrecoverable."

Unrecoverable is that portion of DPIIP and UPIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Uncertainty Ranges are described by the Canadian Oil and Gas Evaluation Handbook as low, best, and high estimates for reserves and resources 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 (P90) 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 (P50) 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 (P10) that the quantities actually recovered will equal or exceed the high estimate.

MFA is the most common analytical method applied to oil shale. It was first developed in Germany and later modified by the US Bureau of Mines as a method to evaluate oil shale potential. The analysis is a controlled pyrolysis of the sample. The pyrolysis yields distilled vapors of oil, gas, water which are cooled and then separated through centrifuging.

Certain resource estimate volumes disclosed herein are arithmetic sums of multiple estimates of DPIIP or UPIIP, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class as explained under this Resource Definitions section.

Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development but which are not currently considered to be commercially recoverable due to one or more contingencies. Economic Contingent Resources (**ECR**) are those contingent resources that are currently economically recoverable.

"Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

The primary contingencies which currently prevent the classification of Questerre's contingent resource as reserves include but are not limited to:

- the passage of applicable hydrocarbon and environmental legislation and regulations;
- local acceptability, including securing social license to operate;
- preparation of firm development plans, including determination of the specific scope and timing of projects;
- project sanction;
- access to capital markets;
- shareholder and regulatory approvals as applicable;
- access to required services and field development infrastructure;
- oil and natural gas prices in Canada;
- demonstration of economic viability;
- future drilling program and testing results;
- further reservoir delineation and studies;
- facility design work;
- corporate commitment;
- development timing;
- limitations to development based on adverse topography or other surface restrictions; and
- the uncertainty regarding marketing and transportation of natural gas from development areas.

Prospective Resources

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.

Prospective resources are defined in the COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from unknown accumulations by application of future development projects. Prospective resources have both an associated chance of discovery (CoDis) and a chance of development (CoDev). There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources or that Questerre will produce any portion of the volumes currently classified as prospective resources. The estimates of prospective resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. The risked net present value of the future net revenue from the prospective resources does not represent the fair market value of the prospective resources. Actual prospective resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Questerre will produce any portion of the resources currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the contingent resources described exists in the quantities predicted or estimated and that the contingent resources can be profitably produced in the future. **The net present value of the future net revenue from the contingent resources does not necessarily represent the fair market value of the contingent resources.** Actual contingent resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

APPENDIX E
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
Dennis Frank Sykora, Chair	Yes	Yes	Mr. Sykora is an independent businessman. Mr. Sykora was formerly a director of High Arctic Energy Services Inc. ("**High Arctic**"), a TSX listed oilfield services company from 2007 to 2016. He was also employed in various executive positions at High Arctic, including Interim Chief Executive Officer, Executive Vice President, General Counsel and Chief Restructuring Officer. Mr. Sykora was a director and member of the Audit Committee for Canadian First Financial Group and CFF Bank from 2012 to 2014. Prior to joining High Arctic, Mr. Sykora was President of Roll'n International Group from 1996 to 2007. Mr. Sykora is both a Chartered Accountant and a lawyer and a member of the Law Society of Alberta. He practiced with Felesky Flynn LLP from 1991 to 1996 and with Ernst & Young from 1981 to 1990. Mr. Sykora holds a Bachelor of Commerce from the University of Saskatchewan, a Bachelor of Law from the University of Calgary.

Name	Independent	Financially Literate	Relevant Education and Experience
Earl Hickok	Yes	Yes	Mr. Hickok is currently President and Chief Executive Officer of TSO Energy Corp., a private exploration and production company since 2010. Prior thereto, he was President, Chief Operating Officer and a Director of Tusk Energy Corp. from 2005 to 2009. Mr. Hickok holds a Bachelor of Engineering degree from Lakehead University in Ontario and is a registered professional engineer with APEGA.
Bjorn Inge Tonnessen	Yes	Yes	Mr. Tonnessen is an independent businessman. From June 2012 to June 2016, he was President of Spike Exploration, a private Norwegian exploration and production company. Prior thereto, he was Managing Director in Norway and Executive Vice President License Management for the Svenska Group, a private Swedish based exploration and production company. 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

Name	Independent	Financially Literate	Relevant Education and Experience
			Engineering from Stavanger University in Norway and an MBA equivalent degree from Stockholm University in Sweden.

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 $138,000 in 2016 and $133,000 in 2015.

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 $25,000 in 2016 and $6,832 in 2015.

Tax Fees

Fees in the amount of $10,150 were billed in 2016 for professional services rendered by the Corporation's external auditor for tax compliance, tax advice and tax planning.

All Other Fees

No amounts were billed in each of the last two fiscal years for products and services provided by the Corporation's auditors other than services reported above.

APPENDIX F
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's 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.