ANNUAL INFORMATION FORM

for the year ended December 31, 2016

March 15, 2017

TABLE OF CONTENTS

ABBREVIATIONS

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	one barrel	Mcf	one thousand cubic feet
bbl	barrels	Mcfe	one thousand cubic feet of natural gas equivalent on the basis of 6 Mcfe for 1 bbl of oil (unless otherwise indicated)
bbl/d	barrels per day	MMcf	one million cubic feet
Mbbl	thousand barrels	Bcf	one billion cubic feet
BOE	barrels of oil equivalent of natural gas on the basis of 1 BOE for 6 Mcf of natural gas (unless otherwise indicated)	Mcf/d	one thousand cubic feet per day
MBOE	one thousand barrels of oil equivalent	MMcf/d	one million cubic feet per day
MMBOE	one million barrels of oil equivalent	GJ	gigajoule
BOE/d	barrels of oil equivalent per day	GJs/d	gigajoules per day
NGL	natural gas liquids	Btu	British thermal unit
stb	standard stock tank barrel	MMbtu	million British thermal units

BOEs or Mcfe may be misleading, particularly if used in isolation. A BOE or Mcfe conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion factor is an industry accepted norm and is not based on either energy content or current prices. 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 Mcf:1 bbl, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indication of value.

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
m^3	cubic metres
$000's	thousands of dollars
WCS	Western Canadian Select, the standard reference for heavy blended crude, price paid at Hardisty, Alberta
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

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

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

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"**BMEC**" means Black Mountain Energy Corporation, a corporation incorporated under the laws of Alberta which was amalgamated with Old Gear on May 1, 2010;

"**BMEC Acquisition**" means the offer of BMEC to purchase all of the issued and outstanding Class A common shares of Old Gear from the shareholders of Old Gear in exchange for 1.4 common shares of BMEC and 0.258125 non-voting preferred shares of BMEC for each Class A common share of Old Gear outstanding;

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

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means common shares in the capital of Gear;

"**Convertible Debenture Indenture**" means the convertible debenture indenture dated November 30, 2015 between the Corporation and Computershare Trust Company of Canada governing the terms of the Convertible Debentures;

"**Convertible Debentures**" means the $14.8 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures of Gear;

"**Corporation**" or "**Gear**" means Gear Energy Ltd., a corporation amalgamated under the laws of the Province of Alberta;

"**EOR**" means enhanced oil recovery;

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta;

"**GLJ Report**" means the independent engineering evaluation of Gear's oil, natural gas liquids and natural gas interests prepared by GLJ effective December 31, 2016 and dated February 15, 2017;

"**Gross**" means:

(a) in relation to an entity's interest in production and reserves, its "company gross reserves", which are such entity's working interest (operating and non-operating) before deduction of royalties and without including any royalty interest of such entity;

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

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

"**Net**" means:

(a) in relation to an entity's interest in production and reserves, such entity's interest (operating and non-operating) after deduction of royalties obligations, plus the entity's royalty interest in production or reserves;

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

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

"**New Credit Facilities**" means the $50 million credit facility with a syndicate of lenders led by Alberta Treasury Branches entered into by Gear on July 27, 2016 concurrently with the completion of the Striker Arrangement;

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* adopted by the Canadian Securities Administrators;

"**Old Gear**" means Gear Energy Ltd., a corporation incorporated under the laws of Alberta which was amalgamated with BMEC on May 1, 2010;

"**Old Credit Facility**" means the $60 million credit facility with a syndicate of banks entered into by Gear on April 25, 2013, as amended from time to time, which was repaid in full and terminated on July 27, 2016 concurrently with the completion of the Striker Arrangement;

"**OPEC**" means the Organization of the Petroleum Exporting Countries;

"**Options**" means options to purchase Common Shares granted under the share option plan of the Corporation;

"**Preferred Shares**" means preferred shares, issuable in series, in the capital of Gear;

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval, accessible at www.sedar.com;

"**Series 1 Preferred Shares**" means the authorized Series 1 preferred shares in the capital of Gear;

"**Striker**" means Striker Exploration Corp. a corporation amalgamated under the laws of Alberta which was amalgamated with Gear on July 29, 2016;

"**Striker Arrangement**" means the acquisition by Gear of all the issued and outstanding common shares of Striker pursuant to a plan of arrangement under the ABCA whereby shareholders of Striker received 2.325 Common Shares for each share of Striker;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5^{th} Supp.), as amended, including the regulations;

"**TSX**" means the Toronto Stock Exchange;

"**2015 Debenture Private Placement**" has the meaning ascribed to it in the section "*General Development of the Business – Three Year History – Year Ended December 31, 2015*";

"**2015 Prospectus Offering**" has the meaning ascribed to it in the section "*General Development of the Business – Three Year History – Year Ended December 31, 2015*";

"**2015 Share Private Placement**" has the meaning ascribed to it in the section "*General Development of the Business – Three Year History – Year Ended December 31, 2015*"; and

"**2016 Prospectus Offering**" has the meaning ascribed to it in the section "*General Development of the Business – Three Year History – Year Ended December 31, 2016*".

CONVENTIONS

Certain terms used herein are defined under the heading "*Certain Definitions*".

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2016.

READER ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, the financial and business prospects and financial outlook, reserve and production estimates, drilling and re-completion plans, timing of drilling, re-completion and tie-in of wells, expected abandonment and reclamation activities, expected future abandonment and reclamation obligations, productive capacity of wells, details of capital expenditure activity and the timing thereof, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, price differentials, exchange rates, production expenses, transportation costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These forward-looking statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with volatility of commodity prices, oil and gas exploration, development, exploitation, production, changes to the Corporation's capital budget, marketing and transportation, loss of markets, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals, ability to access sufficient capital from internal and external sources, risks relating to the Corporation's ability to repay amounts outstanding under the New Credit Facilities when, and if, required and the risk factors outlined under "*Risk Factors*" and elsewhere herein. The recovery and reserve estimates of the Corporation's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Corporation believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Corporation can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this Annual Information Form, assumptions have been made regarding, among other things: future oil and natural gas prices; the Corporation's current capital budget for 2017; the Corporation's potential drilling locations and budget for 2017 if commodity prices change, upwards or downwards, in a material fashion; the general stability of the economic and political environment in which the Corporation operates; the impact of increasing competition; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Corporation has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

CORPORATE STRUCTURE

Name, Address and Incorporation

Gear is a Canadian exploration and production company with heavy and light oil production in central Alberta and west central Saskatchewan.

Gear was incorporated on June 25, 2007 under the ABCA as "Black Mountain Energy Corporation". On January 29, 2010, BMEC acquired all of the issued and outstanding common shares of Old Gear pursuant to the BMEC Acquisition. BMEC and Old Gear amalgamated on May 1, 2010 and continued under the name "Gear Energy Ltd."

On June 3, 2010, Gear amended its articles to: (i) consolidate the Common Shares on the basis of one post-consolidation Common Share for every five pre-consolidation Common Shares; and (ii) to convert the then-issued and outstanding Series 1 Preferred Shares to Common Shares on the basis of one post-consolidation Common Share for every five pre-consolidation Series 1 Preferred Shares.

Gear was amalgamated under the provisions of the ABCA on September 21, 2011 with its wholly-owned subsidiary, Lift Resources Inc., and continued under the name "Gear Energy Ltd."

Pursuant to the Striker Arrangement, Gear was amalgamated with Striker on July 27, 2016, and continued under the name "Gear Energy Ltd.".

The head office of Gear is located at Suite 2600, 240 – 4th Avenue S.W., Calgary, Alberta T2P 4H4 and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The following is a summary of the significant events in the development of the Corporation's business over the last three completed financial years.

Year Ended December 31, 2014

On March 28, 2014, Gear completed a public offering of 15,875,000 Common Shares, including 1,875,000 Common Shares issued pursuant to the full exercise of the over-allotment option granted to the underwriters under the offering, at a price of $4.00 per Common Share for gross proceeds of $63,500,000.

On April 30, 2014, Gear completed the acquisition of heavy oil assets focused near Gear's core producing areas in Wildmere, Alberta and Maidstone, Saskatchewan, which included over 2,000 BOE/d of high working interest, operated heavy gravity crude oil production for a purchase price of $85 million (before closing adjustments) and an effective date of March 1, 2014.

On June 2, 2014, Mr. Harry English was appointed to the Board.

On November 11, 2014, the Old Credit Facility was increased from $100 million to $130 million.

Total capital spending in 2014, including net acquisitions, was $164 million. Aside from the acquisition noted above, the majority of these funds were spent to drill 76 gross (68.6 net) wells with a 91% success rate. In addition to focussing on the existing areas of Wildmere, Alberta and Maidstone, Saskatchewan, the 2014 drilling program focused on new assets acquired in 2014 at Morgan, Alberta and Paradise Hill, Saskatchewan and new exploratory play areas.

Year Ended December 31, 2015

On June 30, 2015, Mr. Bryan Dozzi was appointed as Vice President, Engineering and the Old Credit Facility was decreased from $130 million to $90 million.

On November 30, 2015, Gear completed: (i) a public offering of 12,000,000 Common Shares at a price of $0.75 per Common Share (the "**2015 Prospectus Offering**"); (ii) a private placement of 2,666,700 Common Shares at a price of $0.75 per Common Share (the "**2015 Share Private Placement**"); and (iii) a private placement of $14,800,000 aggregate principal amount of Convertible Debentures at a price of $1,000 per Convertible Debenture (the "**2015 Debenture Private Placement**"), for aggregate gross proceeds from the 2015 Prospectus Offering, 2015 Share Private Placement and 2015 Debenture Private Placement of approximately $25.8 million. A significant shareholder of Gear purchased all of the Common Shares pursuant to the 2015 Share Private Placement and $11.593 million aggregate principal amount of Convertible Debentures pursuant to the 2015 Debenture Private Placement, representing 78.3% of the 2015 Debenture Private Placement. As a result, on closing of the 2015 Prospectus Offering, 2015 Share Private Placement and 2015 Debenture Private Placement, the significant shareholder owned, controlled or directed, directly or indirectly, approximately 19.7% of the issued and outstanding Common Shares and $11.593 million aggregate principal amount of Convertible Debentures. For a description of the material characteristics of the Convertible Debentures, see "*Description of Capital Structure – Convertible Debentures*". Additionally on November 30, 2015, Gear's Old Credit Facility was amended and restated to provide for a new borrowing base of $60 million.

Total capital spending in 2015, including net acquisitions, was $14 million. The majority of these funds were spent to drill 12 gross (12 net) horizontal oil wells with a 100% success rate. The 2015 drilling program focussed on multiple areas including Wildmere, Alberta, Morgan, Alberta and Paradise Hill, Saskatchewan.

Year Ended December 31, 2016

On June 29, 2016, Gear completed a public offering of 28,750,000 Common Shares at a price of $0.70 per Common Share (the "**2016 Prospectus Offering**"), for aggregate gross proceeds from the 2016 Prospectus Offering of approximately $20.1 million.

On July 27, 2016, Gear completed the Striker Arrangement whereby the Corporation acquired all of the issued and outstanding common shares of Striker pursuant to a plan of arrangement under the ABCA. Shareholders of Striker received 2.325 Common Shares for each share of Striker owned resulting in the issuance of 76.2 million Common Shares by Gear. Gear also assumed Striker's debt of approximately $9 million, after taking into account Striker's transaction costs. Pursuant to the rules of the TSX, Gear required the approval of the Corporation's shareholders for the issuance of Common Shares pursuant to the Striker Arrangement which was received at a special meeting of the Corporation's shareholders held on July 26, 2016. Concurrent with the closing of the Striker Arrangement, Messrs. Neil Roszell, John O'Connell and Kevin Olson, three former members of Striker's board of directors, were also appointed to the Board and Mr. Greg Bay retired from the Board. Striker warrants to purchase 650,000 Striker common shares held or controlled by certain directors of Striker who were appointed to the Board survived the Striker Arrangement. The warrants now entitle the holders to purchase an aggregate of 1,511,250 Common Shares of Gear at an exercise price of $1.03 per Common Share. Following completion of the Striker Arrangement, on July 29, 2016, Gear amalgamated with Striker, then a wholly-owned subsidiary, and continued under the name "Gear Energy Ltd.".

Concurrent with the completion of the Striker Arrangement, on July 27, 2016, Gear repaid all amounts owing and terminated both the Old Credit Facilities and Striker's credit facility and entered into the New Credit Facilities to provide for a new borrowing base of $50 million, consisting of a $42,500,000 syndicated credit facility and a $7,500,000 operating credit facility available on a fully revolving basis with the borrowing base being subject to a semi-annual review. The New Credit Facilities contain a financial covenant to maintain an adjusted working capital ratio of not less than 1.0:1, with adjusted working capital ratio being defined as current assets less unrealized hedging gains, plus the undrawn portion of the credit facilities divided by accounts payable and accrued liabilities. The undrawn portion of the New Credit Facilities is subject to a standby fee in the range of 50 bps to 100 bps. In the fourth quarter, as part of the regular semi-annual borrowing base review, the maturity date on the New Credit Facilities was amended to be one year after the end of the revolving period. The current revolving period ends on May 31, 2017 and is extendible for 364 days with the consent of the lenders. The next semi-annual borrowing base review of the New Credit Facilities will occur on or about May 31, 2017.

On November 9, 2016, Mr. Dustin Ressler was appointed Vice President, Exploration.

On November 24, 2016, Gear completed a non-brokered private placement offering of 1,176,500 Common Shares at a price of $0.85 per share, issued on a Canadian exploration expense ("**CEE**") flow-through basis pursuant to the provisions of the Tax Act for gross proceeds to the Corporation of $1,000,025. Pursuant to the provisions in the Tax Act, Gear renounced the eligible CEE to purchasers of the flow-through Common Shares prior to December 31, 2016 in the aggregate amount of the gross proceeds raised from the issue and sale of the flow-through Common Shares and will be required to incur the CEE effective on or prior to December 31, 2017.

Total capital spending in 2016, including net acquisitions, was $72 million. Aside from the Striker Arrangement, the majority of these funds were spent to drill 13 gross (13 net) horizontal oil wells with a 100% success rate. The 2016 drilling program focussed on multiple areas including Wildmere, Alberta, Wilson Creek, Alberta and Paradise Hill, Saskatchewan.

Recent Developments

Gear's currently approved capital budget for 2017 is $45 million. Approximately $33 million of which will be dedicated to drilling low risk horizontal oil wells. An additional $9 million of the budget will be focused on the implementation of pilot water floods in the Wilson Creek area and in Killam, Alberta, as well as a variety of small infrastructure projects, recompletions, land, seismic and corporate capital. The remaining $3 million will be focused on strategic abandonment and reclamation projects designed to maintain strong corporate liability ratios in both Alberta and Saskatchewan.

Significant Acquisitions

The Striker Arrangement was the only significant acquisition completed by the Corporation during its most recently completed financial year for which disclosure was required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*. Gear filed a Form 51-102F4 in respect of the Striker Arrangement on July 27, 2016 on SEDAR. Pursuant to the Striker Arrangement, Gear and Striker completed a previously announced business combination pursuant to a plan of arrangement under the ABCA on July 27, 2016.

For more information on the Striker Arrangement see "*Three Year History – Year Ended December 31, 2016*".

DESCRIPTION OF THE BUSINESS

General

Gear is a Calgary, Alberta based junior Canadian crude oil and natural gas exploration and production company. All of the Corporation's oil and gas properties are located in Alberta, British Columbia and Saskatchewan. The Corporation currently has core holdings in central Alberta and west central Saskatchewan. The Corporation has a significant land position in Alberta, British Columbia and Saskatchewan and intends to continue to evaluate additional oil and gas assets in Alberta, British Columbia and Saskatchewan.

Business Plan and Corporate Strategy

Gear's strategy is to provide long term production and cash flow growth on a per debt adjusted share basis as a low cost oil and gas operator. The Corporation's business plan contemplates that the Corporation will pursue exploration, development and exploitation drilling, complemented with property or corporate acquisitions exhibiting synergies in land, facilities, production and operating efficiencies.

Gear plans to achieve this growth by pursuing assets with the following characteristics:

- Geographically focused
- Definable resource base with low risk production
- Repeatable projects that are statistically economic
- Horizontally amenable producing horizons
- Easy surface access and existing infrastructure
- High operatorship percentage

See "*Risk Factors*".

Gear's strategy to attempt to enhance returns on its assets is by:

- Drilling and developing on controlled lands
- Focusing on operational and cost efficiencies
- Continually improving operations through innovation and imitation
- Adopting and refining advanced drilling and completing techniques
- Pursuing strategic acquisitions with significant potential synergies

In reviewing potential drilling or acquisition opportunities, Gear gives consideration to a variety of criteria, including: (i) the capital required to secure or evaluate the investment opportunity; (ii) if successful, the potential return on the project; (iii) the likelihood of success; (iv) the risk of return versus cost of capital; (v) the strategic benefits to Gear; and (vi) Gear's ability to operate a project.

The Board may, in its discretion, approve asset or corporate acquisitions or investments, including those acquisition or investments that do not conform to the guidelines discussed above based upon the Board's consideration of, among other things, the qualitative aspects of the subject properties, including risk profile, technical upside, productive life and asset quality.

In light of the uncertain condition of world oil prices, which began a modest rebound in the latter half of 2016, the Board has approved a conservative $45 million capital expenditure budget for 2017 that principally targets a low risk horizontal oil well drilling program. Gear intends to continuously monitor prices and control capital expenditures throughout 2017 to ensure maintenance of strong project returns and a conservative balance sheet.

The amount of capital the Corporation will expend for its 2017 exploration and development program and the nature of its expenditures may vary materially based on commodity prices, market access, other industry conditions and the Corporation's drilling results as the year progresses. Access to additional capital may spur an expansion of the program; however, any significant reduction in commodity prices or any unexpected reduction in Gear's access to capital may lead to a reduction in the Corporation's 2017 exploration and development program. Although Gear's management remains committed to the above strategy, the current instability and uncertainty in the oil and gas industry and the challenges oil and gas producers continue to face with respect to the availability of funds and access to markets may impact Gear's ability to continue to pursue its business strategy. See "*Risk Factors*" for further details.

Specialized Skill and Knowledge

Gear believes that its team has all of the key components to successfully implement its business plan: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; extensive experience in oil and gas exploration and development in Western Canada; and an entrepreneurial spirit that allows Gear to effectively identify, evaluate and execute on value-added initiatives. See "*Directors and Executive Officers*".

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Companies operating in the upstream petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration and development, commodity prices, foreign exchange rates, interest rates, environmental damages, market access and the current weakness impacting the oil and gas industry as a whole. See "*Risk Factors – Competition*".

Gear expects the intense level of competition to continue in the future. Gear competes with a substantial number of other entities, certain of which have greater technical or financial resources particularly when it comes to acquiring reserves, oil and gas mineral rights, skilled industry personnel, access to end user markets and capital to finance their activities. With the maturing nature of the Western Canadian Sedimentary Basin, access to new prospects is becoming more competitive and complex and Gear's ability to execute its business plan of growing its oil and gas reserves and cash flow will depend not only on the Corporation's ability to exploit and develop existing properties but also its ability to identify and acquire additional properties or prospects for exploratory and development drilling. Gear 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.

Cyclical Nature of Business

In general, the energy business is cyclical in nature and heavily dependent on macro-economic cycles. In periods of economic expansion and growth the demand for energy increases as economies build inventory and productive capacity. Generally speaking in periods of economic contraction or recession, demand for energy declines. These macroeconomic cycles often impact global, North American and local prices for commodities, particularly oil and gas prices. In addition, the actions of OPEC and other oil producing countries and other factors impacting supply of oil will impact the price of oil. See "*Risk Factors – Weakness in the Oil and Gas Industry*".

Demand for heavy oil begins to increase in the spring time and peaks in the summer months as heavy oil is often the base feed stocks which supply refineries, which make end products such as transportation fuels, heating oils, and asphalt for road paving. During the fall, refiners switch from making gasoline for summer driving season and asphalt for paving season and enter turn around season creating temporary lower demand for heavy crudes while these refineries undergo maintenance and repairs. Demand picks up again with a focus on making heating fuels until the spring comes and refiners again switch to focus on building gasoline stocks for the summer season. Demand for light oil can also vary throughout the year, although not usually with the same volatility as heavy oil.

Generally, Gear's operations are not cyclical. With the exception of a few months in the spring when conditions are wet and road damage can occur with heavy traffic, often referred to as "break up", Gear's operating areas are accessible year round. Gear invests capital and has ongoing operations year round with lower levels of activity during "break up". To the extent that a "break up" period is longer or shorter than normal, it can have an impact on Gear's ability to execute its capital expenditure program. See "*Risk Factors – Seasonality*".

Environmental Protection

All phases of the oil and natural gas industry are subject to a variety of federal and provincial legislation. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions or various substances produced in association with oil and natural gas. Compliance with such legislation may require significant expenditures and a breach may result in fines and penalties some of which may be material. Environmental legislation is constantly evolving and is expected to result in stricter standards and enforcement, larger fines and liabilities and potentially increased capital and operating costs. No assurances can be given that environmental laws will not result in a curtailment of production or a material increase in cost adversely affecting the Corporation's financial condition.

For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of Gear see "*Industry Conditions – Environmental Regulation*" and "*Risk Factors – Environmental*".

Employees

As at December 31, 2016, Gear had 15 full time employees and 7 consultants located at its Calgary office, and 8 full time employees, 1 consultant and a number of contract operators in various field locations.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated February 15, 2017. The effective date of the Statement is December 31, 2016 and the preparation date of the Statement is January 25, 2017.

Disclosure of Reserves Data

The Corporation engaged GLJ to provide an evaluation of the Corporation's proved and proved plus probable reserves as at December 31, 2016. The reserves data set forth below (the "**Reserves Data**") is based upon the GLJ Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas proved and probable reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The GLJ Report has been prepared in accordance with the standards and the reserve definitions contained in the COGE Handbook and NI 51-101. The Reserves Committee of the Board has reviewed and approved the GLJ Report and this statement. The Report of Management and

Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

All of the Corporation's reserves are in Canada and, specifically, in the Provinces of Alberta, British Columbia and Saskatchewan.

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs and future capital investments. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF CORPORATION OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

	RESERVES											
	LIGHT AND MEDIUM CRUDE OIL		HEAVY OIL		CONVENTIONAL NATURAL GAS		COAL BED METHANE		NATURAL GAS LIQUIDS		TOTAL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MBOE)	Net (MBOE)
Proved Developed												
Producing	1,921	1,622	3,289	3,059	9,288	8,176	94	87	445	334	7,219	6,393
Non-Producing	158	138	781	729	924	820	-	-	42	32	1,135	1,036
Proved Undeveloped	1,597	1,362	2,457	2,212	6,861	6,010	-	-	240	196	5,438	4,772
Total Proved	3,677	3,122	6,527	6,000	17,073	15,007	94	87	727	563	13,792	12,200
Probable	2,330	1,953	7,335	6,554	12,071	10,423	29	27	498	409	12,179	10,657
Total Proved plus Probable	6,006	5,074	13,862	12,554	29,144	25,430	123	114	1,225	972	25,971	22,857

NET PRESENT VALUES OF FUTURE NET REVENUE

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
RESERVES CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	($/BOE)
Proved Developed											
Producing	156,222	138,545	124,916	114,119	105,357	156,222	138,545	124,916	114,119	105,357	19.54
Non-Producing	31,202	25,371	21,280	18,247	15,904	31,202	25,371	21,280	18,247	15,904	20.55
Proved Undeveloped	97,441	73,808	56,965	44,745	35,658	97,441	73,808	56,965	44,745	35,658	11.94
Total Proved	284,864	237,724	203,161	177,112	156,919	284,864	237,724	203,161	177,112	156,919	16.65
Probable	342,887	248,699	191,487	153,626	126,925	285,068	206,140	158,757	127,669	105,863	17.97
Total Proved plus Probable	627,751	486,424	394,648	330,738	283,844	569,932	443,864	361,918	304,781	262,782	17.27

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2016 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS(1) (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	742,450	88,637	257,476	81,003	30,470	284,864	-	284,864
Total Proved plus Probable	1,487,936	185,507	486,319	149,794	38,565	627,751	57,819	569,932

Note:

(1) Reflects estimated abandonment and reclamation for all wells (both existing and undrilled wells) that have been attributed reserves. See "*Additional Information Relating to Reserves Data – Additional Information Concerning Abandonment and Reclamation Costs*".

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 at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/boe) ($/Mcfe)
Proved Reserves	Light and Medium Crude Oil(1)	74,990	17.03/boe
	Heavy Crude Oil(1)	119,543	19.85/boe
	Conventional Natural Gas(2)	8,589	0.81/Mcfe
	Coal Bed Methane (2)	38	0.44/Mcfe
Proved Plus Probable Reserves	Light Crude Oil and Medium Crude Oil(1)	115,437	16.31/boe
	Heavy Crude Oil(1)	264,266	21.00/boe
	Conventional Natural Gas(2)	14,878	0.78/Mcfe
	Coal Bed Methane (2)	66	0.58/Mcfe

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Columns may not add due to rounding.

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth in the "*Certain Definitions*" and below.

3. Levels of Certainty for Reported Reserves:

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

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

   (b) at least a 50% probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

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

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

4. Forecast Costs and Price Assumptions

   The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Report published by GLJ as at December 31, 2016 are as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL							
	WTI Cushing Oklahoma	Edmonton Oil Price 40° API	WCS Oil Price	Natural Gas AB Plant Gate Spot Gas Price	Pentanes Plus Edmonton	Butanes Price Edmonton	Inflation Rates(1)	Exchange Rate(2)
Year	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/MMBtu)	($Cdn/bbl)	($Cdn/bbl)	%/Year	($US/$Cdn)
Forecast								
2017	55.00	69.33	53.32	3.20	72.11	49.92	2.0	0.750
2018	59.00	72.26	56.79	2.85	74.79	54.19	2.0	0.775
2019	64.00	75.00	61.27	3.02	78.75	56.25	2.0	0.800
2020	67.00	76.36	63.00	3.24	79.80	57.27	2.0	0.825
2021	71.00	78.82	65.90	3.41	82.37	59.12	2.0	0.850
2022	74.00	82.35	69.42	3.60	86.06	61.76	2.0	0.850
2023	77.00	85.88	72.91	3.79	89.32	64.41	2.0	0.850

	OIL							
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Oil Price 40° API ($Cdn/bbl)	WCS Oil Price ($Cdn/bbl)	Natural Gas AB Plant Gate Spot Gas Price ($Cdn/MMBtu)	Pentanes Plus Edmonton ($Cdn/bbl)	Butanes Price Edmonton ($Cdn/bbl)	Inflation Rates(1) %/Year	Exchange Rate(2) ($US/$Cdn)
2024	80.00	89.41	76.45	3.90	92.99	67.06	2.0	0.850
2025	83.00	92.94	79.93	3.97	97.59	69.71	2.0	0.850
2026	86.05	95.61	83.47	4.06	99.91	71.71	2.0	0.850
2027+	Escalated oil, gas and product prices at 2% per year thereafter							

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized, before transportation and financial derivative contracts, by the Corporation for the year ended December 31, 2016, were $2.50 Mcf for natural gas, $55.30/bbl for light and medium oil, $34.74/bbl for heavy oil and $22.89/bbl for NGLs.

5. Well abandonment and lease reclamation costs have only been included for wells (both existing and undrilled wells) that have been attributed reserves. Additional abandonment and lease reclamation costs associated with existing wells with no attributed reserves and facility abandonment and reclamation expenses have not been included in this analysis.

6. The forecast price and cost assumptions assume the continuance of current laws and regulations.

7. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

8. The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis and utilizing the Corporation's tax pools. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

Reconciliations of Changes in Gross Reserves

RECONCILIATION OF
CORPORATION GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS		
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 (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2015	-	-	-	7,419	6,624	14,043	66	181	247
Discoveries[1]	-	-	-	-	-	-	-	-	-
Extensions	-	-	-	801	1,490	2,291	-	-	-
Infill Drilling	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	35	(35)	-	-	-	-
Technical Revisions	4	-	4	(201)	(723)	(924)	1	(3)	(2)
Acquisitions	3,829	2,330	6,158	3	29	33	702	425	1,127
Dispositions	-	-	-	(35)	(18)	(53)	-	(105)	(105)
Economic Factors	-	-	-	(29)	(32)	(62)	(1)	1	-
Production	(157)	-	(157)	(1,467)	-	(1,467)	(41)	-	(41)
December 31, 2016	3,677	2,330	6,006	6,527	7,335	13,862	(727)	498	1,225

Notes:

(1) Columns may not add due to rounding.

FACTORS	CONVENTIONAL NATURAL GAS Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	SHALE GAS Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	COAL BED METHANE Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	TOTAL Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
December 31, 2015	5,462	5,687	11,149	-	2,700	2,700	-	-	-	8,396	8,202	16,598
Discoveries[1]	-	-	-	-	-	-	-	-	-	-	-	-
Extensions	-	-	-	-	-	-	-	-	-	801	1,490	2,291
Infill Drilling	-	-	-	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-	35	(35)	-
Technical Revisions	303	(48)	255	-	-	-	-	-	-	(145)	(734)	(879)
Acquisitions	12,406	6,432	18,838	-	-	-	99	29	128	6,619	3,860	10,479
Dispositions	-	-	-	-	(2,700)	(2,700)	-	-	-	(35)	(573)	(608)
Economic Factors	-	-	-	-	-	-	-	-	-	(30)	(32)	(62)
Production	(1,098)	-	(1,098)	-	-	-	(5)	-	(5)	(1,849)	-	(1,849)
December 31, 2016	17,073	12,071	29,144	-	-	-	94	29	123	13,792	12,179	25,971

Notes:

(1) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the remaining proved undeveloped reserves and the remaining probable undeveloped reserves, each by product type, attributed to Gear's assets for the years ended December 31, 2016, 2015 and 2014.

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl) First Attributed	Light and Medium Crude Oil (Mbbl) Cumulative at Year End	Heavy Crude Oil (Mbbl) First Attributed	Heavy Crude Oil (Mbbl) Cumulative at Year End	Conventional Natural Gas (MMcf) First Attributed	Conventional Natural Gas (MMcf) Cumulative at Year End
2014	-	-	2,176	2,675	-	4,175
2015	-	-	668	2,402	-	4,061
2016	1,597	1,597	801	2,457	2,759	6,861

Notes:

(1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(2) Columns may not add due to rounding.

Year	Shale Gas (MMcf)		Coal Bed Methane (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	-	-	-	-	-	60	2,176	3,431
2015	-	-	-	-	-	59	668	3,138
2016	-	-	-	-	181	240	3,039	5,438

Notes:

(1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(2) Columns may not add due to rounding.

<u>Probable Undeveloped Reserves</u>

Year	Light and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	-	-	2,534	3,824	-	7,795
2015	-	-	970	3,806	-	5,126
2016	1,461	1,461	2,163	4,903	3,687	8,772

Notes:

(1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(2) Columns may not add due to rounding.

Year	Shale Gas(1) (MMcf)		Coal Bed Methane (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	-	-	-	-	-	179	2,534	5,302
2015	-	2,700	-	-	-	179	970	5,289
2016	-	-	-	-	257	331	4,496	8,157

Notes:

(1) Prior to 2015, shale gas was included with conventional natural gas.
(2) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(3) Columns may not add due to rounding.

In general, once proved and/or probable reserves are identified, they are included in Gear's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two to three years; however these locations will continue to be re-evaluated to assess their relative economic merits when compared to other projects available to the Corporation. A number of factors that could result in delayed or cancelled development are as follows:

- development of a superior opportunity inventory to select from;
- changing economic conditions (due to pricing, royalties, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));

- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);

- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and

- surface access issues (landowners, weather conditions, regulatory approvals).

See "*Other Oil and Gas Information – Principal Properties*", "*Other Oil and Gas Information – Future Development Costs*" and "*Other Oil and Gas Information – Capital Expenditures*" for a description of the Corporation's exploration and development plans and expenditures.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently 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, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability and pricing of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any unusually high development costs or operating costs to produce and sell any material portion of its reserves. Where required, capital to construct facilities and pipelines necessary to deliver the forecasted products to market has been deducted from the estimates of cash flows used to calculate future net revenue. The Corporation has not entered into any contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations described under the heading "*Other Oil and Gas Information – Forward Contracts and Marketing*".

The Corporation does not anticipate any unusually high abandonment or reclamation costs. Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Gear's audited financial statements for the year ended December 31, 2016 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

	Forecast Capital Costs (M$)	
Year	Proved Reserves	Proved Plus Probable Reserves
2017	19,879	25,599
2018	37,103	61,021
2019	23,942	43,935

2020	48	9,379
2021	-	9,677
Thereafter	32	184
Total Undiscounted	81,003	149,794

On an ongoing basis, Gear will use internally generated cash flow from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Corporation.

Other Oil and Gas Information

Principal Properties

The Corporation is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of the Corporation's current operations are in the Provinces of Alberta and Saskatchewan, with some minor operations in the Province of British Columbia.

The following is a description of the Corporation's oil and natural gas properties as at the date hereof, unless otherwise stated. The reserve amounts stated are gross reserves, as at December 31, 2016 based on forecast costs and prices as evaluated in the GLJ Report (see "***Reserves Data***"). The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. The production values are all stated on a company interest basis, which includes Gear's royalty interests but does not deduct for royalties payable by Gear.

Wildmere Area, Alberta

The Wildmere field is located within Townships 47, 48 and 49, and Ranges 3, 4, 5 and 6W4, is approximately 200 kilometres southeast of Edmonton, Alberta and is Gear's largest producing property. The property consists of approximately 29,000 gross (27,000 net) acres of lands with no material expiries as the majority of the lands have been continued pursuant to the applicable tenure regulations.

The Wildmere area is a heavy oil area characterized by unconsolidated Upper Mannville group clastic reservoirs with depths ranging from 600 meters to 700 meters. While the Lloydminster and Cummings formations have been the most exploited intervals, the General Petroleum, Colony and Sparky formations have also proven to be successful development targets for heavy oil on Gear acreage.

Each of Gear's Wildmere heavy oil sites is the surface location for one to four wells. Every pad is equipped to operate independently and, as such, the risk of a single event resulting in a material production loss is mitigated. Solution gas is pipeline connected through most of the field allowing wells to share gas for tank heating, to sell gas, or to deliver purchased gas if desired in order to offset propane otherwise used for tank heating. All Wildmere oil production is tank treated to produce sales quality oil before being trucked to sales points.

In 2010, Gear began investigating secondary and tertiary recovery alternatives for the Lloydminster reservoir by cutting core samples and initiating a variety of lab-scale experiments. Testing, numerical reservoir simulation and economic evaluations through 2011 led to a decision to initiate a horizontal polymer flood pilot. In September 2012, a five horizontal well pilot area commenced injection into two horizontal wells. Although a positive production response was noted, the polymer flood pilot was shut down in 2015 as a result of the low realized heavy oil price.

During 2012, Gear drilled 33 gross (31.5 net) wells within the Wildmere area, all resulting in economic production. During 2013, Gear drilled 35 gross (30.9 net) wells with one being abandoned. In 2014, Gear drilled 26 gross (23.3 net) additional wells, with one being abandoned. In 2015, Gear drilled two gross (two net) additional successful wells. In 2016, Gear drilled 3 gross (3 net) quad-lateral un-lined horizontal wells in the Cummings at Wildmere. The original 2016 budget included plans to drill 11 multi-lateral horizontal Wildmere wells into the Cummings formation; however, that plan was put on hold due to poor oil prices. The current plan for 2017 has budgeted to drill 9 gross (9 net) multi-lateral un-lined horizontal heavy oil wells in the Wildmere area. As was the case with the drilling activity in the year ended December 31, 2016, the Corporation continues to expect that future drilling activity will focus more significantly on Cummings multi-lateral un-lined horizontals initially in low risk areas already proven by existing producing wells.

The GLJ Report assigns total proved plus probable reserves of 4,330 Mbbls of heavy crude oil and NGLs and 0.57 Bcf of natural gas as at December 31, 2016 within the Wildmere area. The average production from the area for the fourth quarter of 2016 was 1,486 BOE/d.

Celtic/Paradise Hill, Saskatchewan

The Celtic/Paradise Hill property was acquired as primarily undeveloped non-producing land starting in March of 2014 and is located within Township 52, and Ranges 23 and 24 W3 and is approximately 40 kilometres northeast of Lloydminster Alberta. It is currently comprised of approximately 5,700 gross (5,500 net) acres of land. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

Celtic/Paradise Hill is characterized by unconsolidated Upper Mannville group clastic reservoirs with depths ranging from 500 meters to 650 meters. While the McLaren formation has been the most exploited interval, Sparky and Waseca also hold significant potential as future development targets on Gear acreage.

Consistent with Gear's other heavy oil sites, each one to four well pad is equipped to operate independently and as such, the risk of a single event culminating into a material production loss is mitigated. Solution gas is gathered through a pipeline system and is used to heat production tanks. All oil production is tank treated to produce sales quality oil before being trucked to sales points. In 2014 Gear successfully drilled the first two gross (2 net) half section lined horizontal McLaren oil wells into the area. In 2015, a further three gross (3 net) horizontal wells were successfully drilled. In 2016, Gear drilled eight more gross (8 net) successful horizontal McLaren oil wells. The current plan for 2017 is for a budget of 17 gross (17 net) McLaren horizontal oil wells to be drilled in the area.

The GLJ Report assigns total proved plus probable reserves of 4,168 Mbbls of heavy crude oil at December 31, 2016 within the Celtic area. The average production from the area for the fourth quarter of 2016 was 1,022 BOE/d.

Wilson Creek

The Wilson Creek property was acquired in July 2016 pursuant to the Striker Arrangement and is located primarily within Townships 42 and 43, and Ranges 4 and 5 W5 in Central Alberta. The primary target zone is the regional Basal Belly River consolidated sandstone formation, which is a light oil pool that requires hydraulic fracturing. It is comprised of approximately 36,000 gross (28,000 net) acres of land. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

Wilson Creek development is primarily characterized by the Basal Belly River reservoir with depth of approximately 1,300 meters. The light oil in the area is processed partially at single well batteries and partially with individual wells flow-lined to central facilities. In either case, the resulting clean oil is trucked to the various sales points. The associated gas from Wilson Creek is gathered through third party infrastructure and sold to various parties.

In 2016 following completion of the Striker Arrangement, Gear drilled 2 gross wells (2 net) full section horizontal light oil wells into the Basal Belly River, one of which was completed in late 2016 and the other which was completed in early 2017. Gear plans on drilling five gross (4.8 net) full section Basal Belly River horizontal light oil wells through 2017.

The GLJ Report assigns total proved plus probable reserves of 2,998 Mbbls of light crude oil and NGLs and 4.263 Bcf of natural gas as at December 31, 2016 within Wilson Creek. The total average production from this area for the fourth quarter of 2016 was 618 BOE/d.

Other Areas

The Corporation held interests in a number of wells and lands in other portions of Alberta, British Columbia and Saskatchewan at December 31, 2016. In 2016, Gear did not drill in any of these other areas. Gear also did not participate in any non-operated drills during 2016. For 2017, in addition to the nine wells budgeted to be drilled in Wildmere, the 17 wells to be drilled in the Celtic/Paradise Hill area and the five gross (4.8 net) light oil wells in Wilson Creek Basal Belly River, the budget includes drilling three heavy oil wells in Hoosier, Saskatchewan, two heavy oil wells in an undisclosed area, one medium oil well in Killam, Alberta and one light oil well in Central Alberta.

The GLJ Report assigns total proved plus probable reserves of 9,597 Mbbls of light, medium and heavy crude oil and NGLs and 24,432 Bcf of natural gas as at December 31, 2016 within these other areas. The total average production from these areas for the fourth quarter of 2016 was 3,077 BOE/d

Oil and Gas Wells

The following table sets forth the number and status of oil and gas wells in which the Corporation had a working interest as at December 31, 2016.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	362	311	772	722	448	75	245	198
British Columbia	-	-	-	-	1	1	7	7
Saskatchewan	52	50	153	122	-	-	77	72
Total	414	360	925	845	449	76	329	277

Note:

(1) This table does not include water source wells, injection wells, abandoned wells or wells which have never produced. Producing wells are based on public data status.

Land Holdings Including Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2016.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	161,512	122,877	133,937	120,659	295,449	243,536
British Columbia	5,475	4,524	6,960	6,009	12,435	10,533
Saskatchewan	36,354	32,711	36,889	35,349	36,889	68,060
Total	203,341	160,112	177,786	162,017	344,773	322,129

Gear calculates both its gross and net acres on a per lease basis. Undeveloped lands are calculated by adding the surface area acreage covered by the leases or agreements or portions of the leases or agreements without producing or potentially producing wells. In certain limited circumstances where the Corporation has rights in different formations under the same surface area pursuant to different leases or agreements, we have included the acreage with respect to all such leases or agreements. There are no significant factors or uncertainties associated with the undeveloped land.

Gear has approximately 22,000 net acres of its undeveloped land holdings that may expire by December 31, 2017, a portion of which may be continued pursuant to applicable tenure regulations. Gear plans to drill or submit application to continue selected portions of the above acreage.

Forward Contracts and Marketing

Most of Gear's crude oil and all natural gas production is sold to major marketers on prearranged terms with indexing to published spot pricing. In a typical month, Gear splits the sale of its crude oil between five separate purchasers, one purchaser at a railway terminal and four at pipeline connected terminals. Gear does not set targets on the amount of crude oil to be sold into railway terminals; rather, it directs its oil sales to the highest received price net of transportation. Gear's established method of mitigating counter party risk is to deal with counterparties with strong credit ratings and to accept pre-payment on oil deliveries from smaller purchasers or those with less established credit ratings.

The contract term is generally a 30-day evergreen in the case of pipeline connected crude oil buyers and up to one year for natural gas and natural gas liquids. For crude oil purchaser contracts at rail terminals, Gear generally enters into volume based purchase contracts with 1 to 12 month terms. None of Gear's purchase agreements currently contain material non-performance penalties.

Gear may periodically hedge the price of a portion of its crude oil and natural gas production. The Corporation has no firm gas transportation contracts. The terms of the New Credit Facilities require Gear to hedge 50% of its production net of royalties through December 31, 2017 and to establish hedges through December 31, 2018 by September 30, 2017.

As of the date hereof, the Corporation has the following crude oil and natural gas financial derivatives in place:

Financial WTI Crude Oil Contracts

Term		Contract	Currency	Volume bbl/d	Sold Swap $/bbl	Sold Call $/bbl	Bought Put $/bbl	Sold Put $/bbl
Jan 1, 2017	Jun 30, 2017	Swap	CAD	900	61.39	-	-	-
Jul 1, 2017	Dec 31, 2017	Swap	CAD	400	61.78	-	-	-
Jan 1, 2017	Dec 31, 2017	Collar	CAD	200	-	71.00	60.00	-
Jan 1, 2017	Dec 31, 2017	Collar	CAD	200	-	72.50	60.00	-
Jan 1, 2017	Dec 31, 2017	Collar	CAD	300	-	67.25	60.00	-
Jan 1, 2017	Dec 31, 2017	Collar	CAD	400	-	75.00	60.00	-
Jan 1, 2017	Dec 31, 2017	Collar	CAD	200	-	79.01	60.00	-
Jan 1, 2017	Dec 31, 2017	Collar	CAD	200	-	77.00	62.00	-
Jul 1, 2017	Dec 31, 2017	Collar	CAD	500	-	70.20	60.00	-

Financial WCS Differential Crude Oil Contracts

Term		Contract	Currency	Volume bbl/d	Sold Swap $/bbl	Sold Call $/bbl	Bought Put $/bbl	Sold Put $/bbl
Jan 1, 2017	Dec 31, 2017	Swap	CAD	400	(21.40)	-	-	-

Financial AECO Gas Contracts

Term		Contract	Currency	Volume GJ/d	Sold Swap $/GJ	Sold Call $/GJ	Bought Put $/GJ	Sold Put $/GJ
Jan 1, 2017	Dec 31, 2017	Collar	CAD	750	-	3.30	2.00	-
Jan 1, 2017	Dec 31, 2017	Collar	CAD	1,000	-	3.31	2.70	-
Jan 1, 2017	Dec 31, 2017	Swap	CAD	1,900	3.00	-	-	-
Jan 1, 2018	Dec 31, 2018	Swap	CAD	1,700	2.65			

Tax Horizon

Based on current forward commodity prices, the Corporation does not expect to pay current income tax for the 2017 fiscal year. Gear does not expect to pay income tax in the next 5 years. There are multiple factors which impact the tax horizon of the Corporation, the most notable being production, commodity prices and capital spending levels. Gear currently recognizes a deferred tax asset as current tax pools exceed the book value of property, plant and equipment.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2016:

	(M$)
Corporate Acquisition Cost	58,480
Property Acquisition Costs	
Proved properties	403
Undeveloped properties	-
Exploration costs	1,280
Development costs	13,088
Dispositions	(1,271)
Total	71,980

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2016:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	2	2
Heavy Oil	-	-	11	11
Conventional Natural Gas	-	-	-	-
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total	-	-	13	13

See "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*" for a description of the Corporation's exploration and development plans.

Gear expects to continue focusing on low risk production growth in 2017, primarily targeting high return development drilling, including drilling at Wildmere, Celtic/Paradise Hill, Wilson Creek and select other play areas. Gear also expects to conduct low risk exploration and development activity across a select portion of its asset base, and will continue to monitor prices throughout the year with a vision to potential budget expansion if oil prices strengthen. However, the focus will remain on the delivery of strong project returns and the maintenance of a solid balance sheet. See "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*".

Production Estimates

The following tables disclose, by product type, and by area, the total volume of the Corporation's gross production estimated by GLJ for 2017 in the estimates of future net revenue from gross proved and gross probable reserves disclosed under "*Disclosure of Reserves Data*".

From Gross Proved Reserves:	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Coal Bed Methane (Mcf/d)	BOE (BOE/d)	%
Wildmere	-	1,313	84	-	-	1,327	21
Celtic	-	1,352	-	-	-	1,352	21
Wilson Creek	413	-	973	167	-	742	12
Other	754	1,257	4,934	109	32	2,948	46
Total	1,167	3,922	5,991	276	32	6,369	100

Note:

(1) Columns may not add due to rounding.

From Gross Probable Reserves:	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Coal Bed Methane (Mcf/d)	BOE (BOE/d)	%
Wildmere	-	1,663	91	-	-	1,679	23
Celtic	-	1,713	-	-	-	1,713	23
Wilson Creek	439	-	1,015	174	-	782	11
Other	795	1,364	5,102	113	33	3,126	43
Total	1,234	4,739	6,208	287	33	7,300	100

Note:

(1) Columns may not add due to rounding.

Production History

The following tables summarize certain information in respect of production (which includes royalty interest volumes), product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	2016			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[1]				
Light and Medium Crude Oil (bbls/d)[2]	989	716	-	-
Heavy Crude Oil (bbls/d) [2]	3,997	3,854	4,358	4,190
Conventional Natural Gas (Mcf/d) [3]	5,456	4,232	1,070	1,459
NGLs (bbls/d)	307	145	-	2
Combined (BOE/d)	6,203	5,420	4,536	4,435
Average Price Received (net of transportation)				
Light and Medium Crude Oil ($/bbl)[2]	57.98	51.60	-	-
Heavy Crude Oil ($/bbl) [2]	41.21	37.74	39.00	20.90
Conventional Natural Gas ($/Mcf) [3]	3.07	2.43	1.20	1.52
NGLs ($/bbl)	24.16	20.04	24.70	22.66
Combined ($/BOE)	39.70	36.08	37.75	20.25
Royalties Paid				
Light and Medium Crude Oil ($/bbl)[2]	8.40	8.65	-	-
Heavy Crude Oil ($/bbl) [2]	3.06	3.74	3.02	1.69
Conventional Natural Gas ($/Mcf) [3]	-	0.12	0.27	0.08
NGLs ($/bbl)	9.06	3.01	-	(0.05)
Combined ($/BOE)	3.76	3.97	2.97	1.63
Operating Expenses ($/BOE)				
Light and Medium Crude Oil ($/bbl)[2]	13.90	15.78	-	-
Heavy Crude Oil ($/bbl) [2]	16.55	16.12	13.32	15.23
Conventional Natural Gas ($/Mcf) [3]	2.76	2.99	2.83	2.88
NGLs ($/bbl)	19.24	16.90	13.86	12.97
Combined ($/BOE)	16.25	16.33	13.44	15.34
Netback Received ($/BOE)[4]				
Light and Medium Crude Oil ($/bbl)[2]	35.68	27.17	-	-
Heavy Crude Oil ($/bbl) [2]	21.60	17.88	22.66	3.98
Conventional Natural Gas ($/Mcf) [3]	0.31	(0.68)	(1.90)	(1.44)
NGLs ($/bbl)	(4.14)	0.13	10.84	9.74
Combined ($/BOE)	19.69	15.78	21.34	3.28

Notes:

(1) Before deduction of royalties.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas and by-products from oil wells. Includes immaterial volumes of production from coal bed methane reserves.
(4) Netbacks are calculated by subtracting royalties, and operating and transportation costs from revenues.
(5) Unit values are based on net reserve volumes.

The following table indicates the Corporation's average daily production from its important areas for the year ended December 31, 2016:

	Light and Medium Crude Oil[1] (bbls/d)	Heavy Crude Oil[1] (bbls/d)	Conventional Natural Gas[2] (Mcf/d)	NGLs (bbls/d)	Shale Gas (Mcf/d)	BOE (BOE/d)
Wildmere	-	1,548	200	-	-	1,581
Celtic	-	812	-	-	-	812
Wilson Creek[3]	110	-	341	72	-	238
Other	319	1,739	2,524	42	-	2,520
Total	428	4,099	3,064	114	-	5,152

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Gear acquired its interest in the Wilson Creek assets pursuant to the Striker Arrangement on July 27, 2016. The production reflects the company interest (including royalty interests, but before royalty burdens average daily production from the date of completion of the Striker Arrangement until December 31, 2016.

The Corporation's production for the year ended December 31, 2016 was 80% heavy oil, 8% light and medium oil and 10% natural gas. For the year ended December 31, 2016, approximately 94% of the Corporation's gross revenue was derived from crude oil and NGLs production and 4% was derived from natural gas production.

DIVIDEND POLICY

The Corporation has never declared or paid any cash dividends on the Common Shares. The Corporation currently intends to retain future earnings, if any, for future operations, expansion and debt repayment. Any decision to declare and pay dividends will be made at the discretion of the Board and will depend on, among other things, the Corporation's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions and financing agreement covenants, solvency tests imposed by corporate law and other factors that the Board may deem relevant.

In addition to the foregoing, the Corporation's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future including the terms of the New Credit Facilities. The New Credit Facilities prohibits the Corporation from declaring or paying any dividends to any of its shareholders if: (i) if declaring or paying the dividend would result in a default under the New Credit Facilities; or (ii) during the continuance of a borrowing base shortfall, which is the amount by which the aggregate of all outstanding obligations under the New Credit Facilities exceeds the then current borrowing base of the New Credit Facilities as a result of a reduction or redetermination of the borrowing base (until cured).

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of Preferred Shares, issuable in series, and an unlimited number of Series 1 Preferred Shares, of which 192,915,143 Common Shares and no Series 1 Preferred Shares are currently issued and outstanding. Additionally, the Corporation has $13.7 million aggregate principal amount of Convertible Debentures outstanding. The following is a summary description of the rights, privileges, restrictions and conditions attaching to the Common Shares, the Preferred Shares, the Series 1 Preferred Shares and the Convertible Debentures.

Common Shares

The Corporation has an unlimited number of Common Shares authorized. The holders of Common Shares are entitled to: dividends if, as and when declared by the Board; to vote at any meetings of the holders of Common Shares of the Corporation; and upon liquidation, dissolution or winding up of the Corporation, receive the remaining property and assets of the Corporation. All of the Common Shares outstanding are fully paid and non-assessable.

Preferred Shares

Gear is authorized to issue an unlimited number of Preferred Shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Gear prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding up of Gear, whether voluntary or involuntary, the Preferred Shares are entitled to preference over the Common Shares and any other shares ranking junior to the Preferred Shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the Preferred Shares as may be determined at the time of creation of such series.

Series 1 Preferred Shares

At the date hereof, Gear has created Series 1 Preferred Shares; however, no Series 1 Preferred Shares are outstanding. The holders of Series 1 Preferred Shares are not entitled to receive notice of, attend nor vote at any meetings of the shareholders of the Corporation. Subject to the provisions of any other series of Preferred Shares created after the date of the creation of the Series 1 Preferred Shares, the holders of Series 1 Preferred Shares are entitled to receive, if, as and when declared by the Board, any dividends declared by the Board. Any dividends declared and paid on the Common Shares must also be declared and paid on the Series 1 Preferred Shares, which shall be in priority to the holders of the Common Shares. In the event of liquidation, dissolution or winding-up of the Corporation or any other distribution of assets of the Corporation among its shareholders for the purposes of winding up the affairs of the Corporation, the Series 1 Preferred Shares shall rank in priority to the Common Shares in a sum equivalent to the value of the Series 1 Preferred Shares; provided that the amount to be received by the Series 1 Preferred Shares will be equivalent to the amount to be received per Common Share upon such liquidation, dissolution or winding up and subject to the provisions of any other series of Preferred Shares created after the date of the creation of the Series 1 Preferred Shares.

Convertible Debentures

On November 30, 2015, the Corporation issued $14.8 million aggregate principal amount of Convertible Debentures at a price of $1,000 per Convertible Debenture. The Convertible Debentures are governed by the Convertible Debenture Indenture, which is available for review on www.sedar.com. The Convertible Debentures have a maturity date of November 30, 2020 and carry a coupon of 4.00% per annum payable semi-annually in arrears on November 30th and May 31st until maturity. Each $1,000 principal amount of Convertible Debentures is convertible at the option of the holder at any time prior to the maturity date of the Convertible Debentures, into 1,149.43 Common Shares, representing a conversion price of $0.87 per Common Share. Holders converting their Convertible Debentures are entitled to receive accrued and unpaid interest thereon for the period from the date of the latest interest payment date to, but excluding, the date of conversion. The conversion right of a portion of Convertible Debentures required certain approvals of the shareholders of Gear in accordance with the policies of the TSX, which were received at Gear's annual and special meeting of its shareholders held on May 11, 2016. An aggregate of approximately $1.1 million of Convertible Debentures have been converted resulting in the issuance of approximately 1.3 million Common Shares, leaving $13.7 million in Convertible Debentures outstanding.

The Convertible Debentures will not be redeemable before December 31, 2018. On and after December 31, 2018 and prior to December 31, 2019, the Convertible Debentures will be redeemable at the Corporation's option, in whole or in part, at par plus accrued unpaid interest if the weighted average trading price of the Common Shares for the specified period is not less than 125% of the conversion price of the Convertible Debentures. After December 31, 2019, the Convertible Debentures will be redeemable at the Corporation's option, in whole or in part, at any time at par plus accrued and unpaid interest.

In certain circumstances, the Corporation has the option to satisfy its obligation to repay the principal amount of the Convertible Debentures due at maturity or redemption of the Convertible Debentures by the issuance of Common Shares and the number of such Common Shares will be based on 95% of the weighted average trading price of the Common Shares prior to the date fixed for maturity or redemption.

The Convertible Debentures are direct, subordinated unsecured obligations of the Corporation and rank equally with one another and with all other existing and future subordinated unsecured indebtedness of the Corporation. The conversion price of the Convertible Debentures is subject to standard anti-dilution adjustments as set forth in the Convertible Debenture Indenture.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX under the symbol "GXE". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares on the TSX as reported by the TSX for the periods indicated since the beginning of the year ended December 31, 2016:

	Price Range ($)		Trading
Period	**High**	**Low**	**Volume**
2016			
January	0.61	0.25	3,428,616
February	0.37	0.30	2,386,991
March	0.59	0.35	2,712,209
April	0.82	0.46	3,614,545
May	0.72	0.58	2,648,435
June	0.82	0.56	8,248,586
July	0.69	0.54	11,955,633
August	0.74	0.61	8,329,215
September	0.78	0.66	5,671,328
October	0.85	0.70	10,260,788
November	0.83	0.68	9,091,034
December	1.18	0.79	10,291,422
2017			
January	1.25	0.91	9,163,411
February	1.14	0.88	7,549,248
March (1 – 14)	0.95	0.77	3,066,838

Prior Sales

The following table sets forth the securities of the Corporation issued during the year ended December 31, 2016 that are not listed on the TSX (or any other stock exchange):

Date	Number of Securities	Issue Price Per Security[(1)] ($)	Type of Security
March 1, 2016	854,820	0.35	Options
August 17, 2016	6,250,183	0.71	Options
November 21, 2016	300,000	0.73	Options

Note:

(1) Represents the exercise price of Options.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of management of the Corporation, none of the securities of the Corporation are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

DIRECTORS AND EXECUTIVE OFFICERS

Name, Occupation and Security Holding

The following table sets forth certain information in respect to Gear's directors and executive officers:

Name, Province and Country of Residence	Position(s) with Gear	Principal Occupation During the Five Years Preceding
Don T. Gray(1)(2)(3) Arizona, United States of America	Chairman since January 2010 and a Director since February 2009	Private investor; a director of the Corporation since February 2009 and Chairman of the Corporation since January 2010; a founding partner and President of EIQ Capital Corp., a private capital management company from May 2007 to September 2013; Chairman of the Board of Petrus Resources Ltd., a public oil and gas company, since 2010; prior thereto, Mr. Gray was the Chief Executive Officer of Peyto Exploration & Development Corp. (formerly Peyto Energy Trust) ("**Peyto**") from August 2006 to January 2007; prior thereto, Mr. Gray was the President and Chief Executive Officer of Peyto from October 1998 to August 2006.
Peter Verburg(1)(3) Alberta, Canada	Director since July 2009	A founding partner and President of EIQ Capital Corp., a private investment firm, since September 2013; prior thereto, Managing Director of EIQ Capital Corp. since March 2008; prior thereto Vice President, Investment Banking of GMP Securities L.P. since February 2005.
Raymond Cej(2)(3) Alberta, Canada	Director since January 2013	An independent businessman; President of Teine Energy Ltd., a private oil and gas company from July 2010 to April 2014; President of Marble Point Energy Ltd. from January 2010 to July 2010; prior thereto, a senior executive for Shell Canada for 26 years.
Harry English(1) Alberta, Canada	Director since June 2014	Corporate director and independent businessman since June 2014. Prior thereto, partner at Deloitte LLP, Calgary since 2002.
John O'Connell(3) Alberta, Canada	Director since July 2016	Since November 2010, Chairman and Chief Executive Officer of Davis-Rea Ltd., an investment management company.
Kevin Olson(1)(2)(3) Alberta, Canada	Director since July 2016	Since June 2011, President of Kyklopes Capital Management Ltd. Prior thereto, Mr. Olson was a Portfolio Manager with EnergyX Equity Inc. from 2001 to 2011.
Neil Roszell(2) Alberta, Canada	Director since July 2016	President and Chief Executive Officer of Raging River Exploration Inc. since March 2012. Prior thereto, President and Chief Executive Officer of Wild Stream Exploration Inc. from October 2009 to March 2012.

Name, Province and Country of Residence	Position(s) with Gear	Principal Occupation During the Five Years Preceding
Ingram Gillmore Alberta, Canada	President, Chief Executive Officer since May 2010 and a Director since June 2010	President and Chief Executive Officer of the Corporation since May 2010; prior thereto Vice President, Engineering at ARC Resources Ltd. ("**ARC**") since January 2007; prior thereto, Manager Engineering at ARC since 2005.
Yvan Chretien Alberta, Canada	Vice President, Land since September 2010	Vice President, Land of Gear since September 2010; prior thereto, Vice-President, Land at ARC from 2006 to March 2010.
Bryan Dozzi Alberta, Canada	Vice President, Engineering since June 2015	Vice President, Engineering since June 2015; prior thereto, Engineering Manager of the Corporation from April 2014 to June 2015 and Vice President, Business Development at Rock Energy Inc. from December 2010 to December 2012.
David Hwang Alberta, Canada	Vice President, Finance and Chief Financial Officer since June 2011	Vice President, Finance of Gear since June 2011; prior thereto, controller at ARC since 2010 and, prior thereto, manager at ARC since 2006.
Jason Kaluski Alberta, Canada	Vice President, Operations since March 2011	Vice President, Operations of Gear since March 2011; prior thereto, manager of operations for Questerre Energy Corporation from 2008 to 2011.
Dustin Ressler Alberta, Canada	Vice President, Exploration since November 2016	Vice President, Exploration since November 2016; prior thereto, Geology Manager with the Corporation from April 2014 to October 2016 and geologist at Gear from October 2010 to April 2014.
Edward (Ted) Brown Alberta, Canada	Corporate Secretary since August 2015	Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 2005.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation and Governance Committee.
(4) Gear does not have an Executive Committee.
(5) Gear's directors will hold office until the next annual general meeting of the Corporation's shareholders or until each director's successor is appointed or elected pursuant to the ABCA.

As at the date of this Annual Information Form, the number of Common Shares beneficially owned, or controlled or directed, directly or indirectly, by all of the directors and officers of Gear is 31,599,564 Common Shares constituting approximately 16% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

Other than as disclosed below, to the knowledge of Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Gear), that: (a) 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 (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

To the knowledge of Gear, except as described above, no director or executive officer of Gear (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Gear to affect materially the control of Gear: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Gear) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr. Cej was, prior to January 26, 2010, a trustee of Impax Energy Services Income Trust (the "**Trust**"). On December 14, 2009, the Trust filed for creditor protection in order to facilitate an orderly sale and wind-up of operations. On January 26, 2010, all of the trustees and directors of the Trust resigned following the sale of substantially all of the assets of the Trust. Upon the resignations of the trustees and directors, trading in the units of the Trust was suspended for failure to maintain a minimum number of directors as required under the rules of the TSX Venture Exchange.

Penalties or Sanctions

To the knowledge of Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Gear to affect materially the control of Gear, has been subject to: (a) 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 (b) 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.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. 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 AND REGULATORY ACTIONS

Legal Proceedings

None of the Corporation or any of its subsidiaries is a party to any legal proceeding nor was it a party to any legal proceeding during the financial year ended December 31, 2016, nor is the Corporation aware of any contemplated legal proceeding involving the Corporation or its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of the Corporation.

Regulatory Actions

During the year ended December 31, 2016, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) any other 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.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set forth herein, there are no material interests, direct or indirect, of any director or executive officer of the Corporation, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of the Corporation's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation, other than as disclosed elsewhere in this Annual Information Form.

Certain directors and officers of the Corporation subscribed for approximately 10% of the Common Shares sold pursuant to the 2015 Prospectus Offering. Additionally, the Corporation's significant shareholder subscribed for all of the Common Shares pursuant to the 2015 Share Private Placement and $11.593 million aggregate principal amount of Convertible Debentures, representing approximately 78.3% of the Convertible Debentures sold pursuant to the 2015 Debenture Private Placement. See "*General Development of the Business – Three Year History – Year Ended December 31, 2015*" for further descriptions of the Prospectus Offering, 2015 Share Private Placement and 2015 Debenture Private Placement.

Certain directors and officers of the Corporation (including certain former directors of Striker who became directors of Gear upon completion of the Striker Arrangement) subscribed for approximately 15.6% of the Common Shares sold pursuant to the 2016 Prospectus Offering.

Pursuant to the Striker Arrangement, Striker warrants to purchase 650,000 Striker common shares held or controlled by certain directors of Striker who were appointed to the Board survived the Striker Arrangement. The warrants now entitle the holders to purchase an aggregate of 1,511,250 Common Shares of Gear at an exercise price of $1.03 per Common Share.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), the Corporation has not entered into any material contracts during the last financial year, or before the last financial year which are still in effect, other than the Convertible Debenture Indenture (see "*General Development of the Business – Three Year History – Year Ended December 31, 2015*" and "*Description of Capital Structure – Convertible Debentures*"), which is available on www.sedar.com.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are Deloitte LLP, the Corporation's independent auditors and GLJ, the Corporation's independent engineering evaluators.

Interests of Experts

To the Corporation's knowledge, there were no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of its associates or affiliates: (i) held by GLJ or by the "designated professionals" (as defined in Form 51-102F2 to National Instrument 51-102) of GLJ, when GLJ prepared the report, valuation, statement or opinion referred to herein as having been prepared by GLJ; (ii) received by GLJ or by the "designated professionals" of GLJ, after the time specified above; or (iii) to be received by GLJ or by the "designated professionals" of GLJ; except in each case for the ownership of Common Shares, which in respect of GLJ and GLJ's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares. In addition, neither GLJ, nor any director, officer or employee of GLJ, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

Deloitte LLP is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

AUDIT COMMITTEE INFORMATION

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 Schedule "C".

Composition of the Audit Committee

The audit committee (the "**Audit Committee**") is comprised of Messrs. Harry English (Chair), Don T. Gray, Kevin Olson and Peter Verburg. The following chart sets out the assessment of each of the proposed Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Don T. Gray Alberta, Canada	Yes	Yes	Mr. Gray holds a BSc. in petroleum engineering from Texas A&M University and has over 25 years experience in the Canadian oil and gas business in various capacities. Mr. Gray is a Co-Founder and former President and Chief Executive Officer of Peyto and is also Chairman and co-founder of Petrus Resources Ltd., and Chairman of EIQ Capital Corp., a private investment company.
Harry English Alberta, Canada	Yes	Yes	Mr. English graduated with a Bachelor of Science (Honours) from the University of St. Andrews, Scotland in 1976 and is a member of the Canadian Institute of Chartered Accountants. He spent his 37-year career until May 2014 in professional practice, primarily in the energy business, most recently as a senior audit partner with Deloitte LLP.
Kevin Olson Alberta, Canada	Yes	Yes	Mr. Olson holds a Bachelor of Commerce from the University of Calgary and has in excess of 20 years experience in the Canadian oil and gas business in various capacities. He is the President of Kyklopes Capital Management, being the manager of a private equity fund, and has held a similar position since October 2001. From 2000 to 2001, Mr. Olson served as Vice-President, Corporate Development of Northrock Resources Ltd. Prior thereto, Mr. Olson was Vice President, Corporate Finance at FirstEnergy Capital Corp.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Peter Verburg Alberta, Canada	Yes	Yes	Mr. Verburg holds an MBA from the University of Calgary. He is currently the President of EIQ Capital Corp., a private investment company. He was formerly Managing Director of EIQ Capital since 2008, and prior thereto an officer at GMP Securities L.P., working in the Corporate Finance energy group since 2005.

Each of the members of the Audit Committee is considered "financially literate" and is considered "independent" within the meaning of National Instrument 52-110 – *Audit Committees*.

The Corporation believes that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by the Corporation to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting.

Pre-Approval of Policies and Procedures

The Corporation has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by Deloitte LLP. The Audit Committee will approve the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, reoccurring or otherwise likely to be provided by Deloitte LLP during the current fiscal year and the Audit Committee will be informed of each non-audit service, as applicable. The list of services will be sufficiently detailed as to the particular services to be provided to ensure that the Audit Committee knows precisely what services it is being asked to pre-approve and it will not be necessary for any member of management to make a judgment as to whether a proposed service fits within pre-approved services.

External Auditors Service Fees

The following table summarizes the fees billed to the Corporation by its auditors, Deloitte LLP, for external audit and other services during the periods indicated:

Year	Audit Fees(1)	Audit -Related Fees(2)	Tax Fees(3)	All Other Fees(4)
	($)	($)	($)	($)
2016	173,981	76,980	23,849	170,571
2015	212,814	-	22,412	146,695

Notes:

(1) Represents the aggregate fees billed by the Corporation's external auditor in each of the last two fiscal years for audit services.

(2) Represents the aggregate fees billed in each of the last two fiscal years by the Corporation's external auditor for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements (and not reported under the heading "Audit Fees").

(3) Represents the aggregate fees billed in each of the last two fiscal years by the Corporation's external auditor for professional services for tax compliance (2016: $nil; 2015: $nil), tax advice (2016: $23,849; 2015: $22,412) and tax planning (2016: $nil; 2015: $nil).

(4) Represents the aggregate fees billed in each of the last two fiscal years by the Corporation's external auditor for products and services not included under the headings "Audit Fees", "Audit Related Fees" and "Tax Fees". In both 2015 and 2016 these amounts relate to consulting fees paid to Deloitte LLP for Gear's regulatory, safety and environmental program.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas, including the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, regional market and transportation issues also influence prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. 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. The NEB underwent a consultation process to update the 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 licences.

Natural Gas

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) 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. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (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 gas industry is uncertain.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands where the Crown does not hold the mineral rights 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 carved out of the working interest owner's interest, from time to time, 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 Canadian 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 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

In Alberta, the Crown owns 81% of the province's mineral rights. The remaining 19% are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF formally took effect on January 1, 2017 for wells drilled after this date. Wells drilled prior to January 1, 2017 will continue to be governed by the "New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) (the "**Alberta Royalty Framework**") for a period of 10 years until January 1, 2027. 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 total depth, length, and proppant placed). The new royalty rate for Pre-Payout under the MRF 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. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently the equivalent of 194 m3 (40 barrels of oil equivalent per day or 345,500 m3 of gas per month), 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.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator ("**AER**").

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, 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 Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale 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 depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from lands where the Crown does not hold the rights to mines and minerals 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 freehold 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**") 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 (the "**Emerging Resource and Technologies Initiative**"). These initiatives apply to wells drilled before January 1, 2017, for a ten year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months 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 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.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, 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 classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an EOR scheme. 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 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 applicable freehold production tax is based on the volume of monthly production, and is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is 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 production tax rate for freehold natural gas liquids is a flat rate of 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.

The Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas 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, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 6% while wells that qualify for the tier two royalty credits are subject to a minimum royalty of 3%. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;

- *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 if the re-entry well event is greater than 2,300 metres and a re-entry date after November 30, 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; and

- *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 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 that 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.

Saskatchewan

In Saskatchewan, the Crown owns approximately 70% of the oil and gas rights. For the Crown lands, taxes (the "**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 m3 for old oil, new oil and third tier oil, and 250 m3 per month for fourth tier oil. Where average wellhead prices are below the established base prices of $100 per m3 for third and fourth tier oil and $50 per m3 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 Government of Saskatchewan, 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 m3 of gas for every m3 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 250,000 m^3 per 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 GJ for third and fourth tier gas and $0.95 per GJ 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 wellhead 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 licenced on or after such date. The new standards apply to existing licenced wells and facilities on July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licences 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. Effective October 27, 2016, the Saskatchewan Ministry of the Economy streamlined a further 20 different service fees, and implemented a Crown Minerals Electronic Registry for oil and gas tenure in Saskatchewan that will provide for certainty of tenure comparable to Alberta and reduce the administrative burden.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. 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. Private ownership of oil and natural gas also exists in such provinces 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.

Each of the provinces of Alberta, British Columbia, and Saskatchewan 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 licence. 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 licences issued after January 1, 2009 at the conclusion of the primary term of the lease or licence.

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, producers 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 regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, 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. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection 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 licences and authorizations, civil liability 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 greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. 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. 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 Government of Canada 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 the proposed moratorium may affect ongoing LNG export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, 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 have 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 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 provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, 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 seven 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.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under 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, licences, registrations, 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 force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands 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 pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit 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% of the provincial 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 and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Deer Region Plan and Upper Athabasca Region Plan have not been started.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**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 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, 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, the Government of 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, the Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers 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. Alberta's *Oil and Gas Conservation Ac*t ("**OGCA**") establishes an orphan fund (the "**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 or is unable to meet its obligations. The 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 licensees and to 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. The AER publishes the liability management rating for each licensee on a monthly basis.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licencee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licencees.

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***") in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("***Redwater***"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA and the *Bankruptcy and Insolvency*

Act ("***BIA***"), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the *BIA*. *Bulletin 16* provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

1. The AER will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.

2. For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.

3. 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 rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

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 an 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:

1. The licensee already has an LMR of 2.0 or higher;

2. The acquisition will improve the licensee's LMR to 2.0 or higher; or

3. The licensee is able to satisfy its obligations, notwithstanding an 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.

The AER implemented 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 5 years. As of April 1, 2015, each licencee is required to bring 20% of its inactive wells into compliance every year, either by reactivating by or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

British Columbia

In British Columbia, the Commission oversees 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 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 the Economy administers the Licencee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licencee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licencee or WIP is defunct or missing. The SK LLR Program requires a licencee 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 licencees of oil, gas and service wells and upstream oil and gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators that it would follow the AER's interim rules by processing all licence transfer applications as non-routine until further notice.

Regulation Targeting Man Made Climate Change

Federal

Regulation targeting man made climate change at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

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 set 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, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors.

As 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), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; 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 Government of Canada 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 Government of Canada 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 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 Government of Canada 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 some uncertainty with regard to the impacts 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

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHG emissions in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

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. As of 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.

A Regulated Emitter can meet its 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 November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan. On June 7, 2016, the *Climate Leadership Implementation Act* ("***CLIA***") was passed into law. The *CLIA* enacted the *Climate Leadership Act* ("***CLA***") introducing a carbon tax on all sources of GHG emissions, subject to certain exemptions. An initial economy-wide levy of $20 per tonne was implemented on January 1, 2017, increasing to $30 per tonne in January of 2018. All fuel consumption—including gasoline and natural gas—will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the SGER framework until the end of 2017; upon the expiry of the SGER, the Government of Alberta intends to transition to a proposed *Carbon Competitiveness Regulation*, in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. Regulations accompanying the *CLIA* have not yet been released.

The passing of the *CLIA* is the first step towards executing the Climate Leadership Plan (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.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. 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.

British Columbia

British Columbia launched its Climate Action Plan in 2008 and met its first interim emission reduction targets in 2012. In February 2008, the Government of 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 GHG emissions. The final scheduled increase took effect on July 1, 2012, wherein the Government of British Columbia froze the tax level to allow other jurisdictions time to adopt comparable carbon pricing mechanisms. In order to make the tax revenue-neutral, the Government of 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.

Further, on April 3, 2008, the Government of 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 Alberta government, the *Cap and Trade Act* establishes an absolute cap on GHG emissions.

The *Greenhouse Gas Emission Reporting Regulation*, implemented under the authority of the *Cap and Trade Act*, set 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*.

Following the 2012 Budget, the Government of British Columbia undertook a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered 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, the Government of British Columbia confirmed that it will keep its revenue-neutral carbon tax–the current carbon tax rates, tax base will be maintained, and revenues will continue to be returned through tax reductions.

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% reduction in GHG emissions from 2006 levels by 2020. Although the MRGGA and related regulations have yet to be proclaimed in force, draft versions indicate that the Government of Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a 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 the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or may be implemented by the new governments. In addition, the inability to get 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 downward price pressure on oil and gas produced in Western Canada and 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, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, the Corporation's cash flow resulting in a reduced capital expenditure budget. Consequently, 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. 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 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 or if it is able to do so, it may be on unfavourable and highly dilutive terms.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. Oil prices are expected to remain volatile as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, OPEC's recent decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, among other factors. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Lower commodity prices may continue to render Gear's development plans uneconomic.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make 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 have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Fluctuations in commodity prices, quality differentials and foreign exchange and interest rates, among other factors, are outside of management's control.

As a result of the recent volatility and low oil prices (in particular with respect to heavy oil) the value of the Corporation's reserves has been impaired, as discussed in the Corporation's management's discussion and analysis for the year ended December 31, 2015. Continued low oil prices or further reduced oil prices could result in further impairments on the value of Gear's reserves. In addition, low oil prices or further reduced oil prices could result in Gear's lenders under the New Credit Facilities reducing Gear's borrowing base or demanding repayment. There is no certainty that Gear would be in a position to make such repayment or that alternative financing would be available on terms acceptable to the Corporation or at all. Any further reduction in oil prices would impact Gear's cash flows, which could result in Gear not being able to fund its 2016 capital program as planned or meet its other obligations, when due.

See "*Weakness in the Oil and Gas Industry*".

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price fluctuations in the Common Shares may be due to the Corporation's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Reader Advisory Regarding Forward- Looking Statements*". The market price for securities on stock markets, including the TSX, is subject to significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market price of the Common Shares. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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 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 the North American Free Trade Agreement, 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 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 begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment 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 the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of its Common Shares.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends 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 availability of, and the ability to acquire, water supplies needed for drilling hydraulic fracturing and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- 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 be unable to market the oil and natural gas that it produces effectively.

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key personnel insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems 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 or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, 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 or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, operations and cash flows. In addition, the federal government has signaled that it plans to review the National Energy Board approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

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 adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation 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 have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, 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 reimbursement 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 or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other 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 Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If the Corporation does implement such technologies, there is no assurance that the Corporation will do so successfully. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, or is unsuccessful in implementing certain technologies, its business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Full 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 oil, natural gas and 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.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. Details of this new regime are scheduled to be finalized and released before March 31, 2016. See "*Industry Conditions - Royalties and Incentives*".

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Liability Management

Alberta, Saskatchewan 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 is unable to satisfy its obligation. 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 to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance requirement. 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. This is of particular concern to junior oil and gas companies that may be disproportionately affected by price instability. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)* 2016 ABQB 278, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See "*Industry Conditions - Liability Management Rating Programs*".

Regulation Targeting Man Made Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the *CLA* come into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions – Regulation Targeting Man Made Climate Change*".

Variations in Foreign Exchange Rates and Interest 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 Corporation's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation'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 Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, 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.

Substantial Capital Requirements

The Corporation 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 Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation'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 Corporation's securities in particular.

Further, if the Corporation'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 Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation 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 and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

As a result of global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation'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 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 affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders.

Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

The Corporation currently has the New Credit Facilities and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under the New Credit Facilities which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding. 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 the New 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 the New Credit Facilities, the lenders under the New Credit Facilities 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 New Credit Facilities may impose operating and financial restrictions on the Corporation that could include 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.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Depressed commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the New Credit Facilities. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness and, even if the Corporation is able to obtain new financing in order to make any required repayment under the New Credit Facilities, 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 the New Credit Facilities, the lenders could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Despite the modest rebound in late 2016, oil prices continue to be depressed and oil as a geopolitical commodity remains volatile. The current available lending limit of the New Credit Facilities is based on the lenders' interpretation of the Corporation's reserves and future commodity prices, of which there can be no assurance that the amount of the available New Credit Facilities will not be decreased at the next scheduled review. Management continues to monitor capital and administrative spending and financing opportunities to fund its future prospects and commitments. No financing agreements have been signed nor can it be assured that such agreements will be reached.

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

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, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

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

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel to the Corporation and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves 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 natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

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

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

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

Insurance

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

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

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

Dilution

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

Management of Growth

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

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations, as the Board of Directors of the Corporation considers relevant.

Litigation

In the normal course of the Corporation'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, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation, and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on the Corporation's financial condition.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of Western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business and financial results.

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 generally 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.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Seasonality

The level of activity in the Canadian oil and natural 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. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. 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 Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Information Technology Systems and Cyber-Security

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation’s information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation’s business, financial condition and results of operations.

Conflicts of Interest

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the

Corporation to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Directors and Executive Officers – Conflicts of Interest*".

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks 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.

Hydraulic Fracturing

Currently the Corporation does not use hydraulic fracturing as a completion technique on its wells, however hydraulic fracturing is a common industry practice and is one that the Corporation may use in the future. Hydraulic fracturing involves the injection of water, sand and small amounts of additives (or such other fluids and materials that may be used from time to time) under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. 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 as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Waterflood

From time to time, the Corporation may undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities the Corporation needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Corporation will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reservoirs. In addition, the Corporation may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Corporation's results of operations.

Additional information on the risks, assumptions and uncertainties are found under the heading "*Reader Advisory Regarding Forward-Looking Statements*" of this Annual Information Form.

ADDITIONAL INFORMATION

Additional information relating to Gear may be found on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Gear's securities and securities authorized for issuance under equity compensation plans is contained in Gear's management information circular relating to the Corporation's most recent annual meeting of shareholders that involved the election of directors.

Additional information is also provided in Gear's financial statements and management's discussion and analysis for the year ended December 31, 2016, which documents may be found on SEDAR at www.sedar.com.

SCHEDULE "A"

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

To the board of directors of Gear Energy Ltd. (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 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 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 audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	**Total**
GLJ Petroleum Consultants	December 31, 2016	Canada	-	394,648	-	**394,648**

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 reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 15, 2017.

(Signed) "Tim R. Freeborn"
Tim R. Freeborn, P. Eng.
Vice President

SCHEDULE "B"

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

Management of Gear Energy Ltd. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "A" to this Annual Information Form.

The Reserves Committee of the board of directors of the Corporation has

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

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

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

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

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

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

(c) the content and filing of this report.

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

Per: (signed) "*Ingram Gillmore*"
Ingram Gillmore
President, Chief Executive Officer and Director

Per: (signed) "*Bryan Dozzi*"
Bryan Dozzi
Vice President, Engineering

Per: (signed) "*Donald T. Gray*"
Donald T. Gray
Director

Per: (signed) "*Raymond Cej*"
Raymond Cej
Director

March 15, 2017

SCHEDULE "C"

GEAR ENERGY LTD.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Gear Energy Ltd. ("**Gear**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;

2. the oversight of management's reporting on internal accounting standards and practices;

3. the review of financial information, accounting systems and procedures;

4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

5. To assist directors of Gear ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

6. To provide better communication between Directors and external auditors;

7. To enhance the external auditor's independence;

8. To increase the credibility and objectivity of financial reports; and

9. To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of Gear ("**Management**") and external auditors.

MEMBERSHIP OF COMMITTEE

1. The Committee will be comprised of at least three (3) Directors or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 – Audit Committees ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be "financially literate" unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

4. For the purposes of this Mandate, "financially literate" has the meaning ascribed thereto in NI 52-110 and means that the member has the ability to read and understand a set of financial statements that present a breadth and level of

complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

MANDATE AND RESPONSIBILITIES OF COMMITTEE

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between Management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Gear's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process may include but not be limited to:

   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between Management and the external auditors; and
   - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Gear's disclosure of other financial information and must periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

   - recommend to the Board the external auditors to be nominated;
   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

- review and pre-approve any non-audit services to be provided to Gear or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Gear) their assessment of the internal controls of Gear, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Gear and its subsidiaries.

7. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).

8. To review and satisfy itself on behalf of the Board that management has adequate procedures in place for reporting and certification under the *Extractive Sector Transparency Measures Act* (Canada) ("**ESTMA**") when the Corporation is required to comply with ESTMA.

9. Establish a procedure for:

    - the receipt, retention and treatment of complaints received by Gear regarding accounting, internal accounting controls or auditing matters; and

    - the confidential, anonymous submission by employees of Gear of concerns regarding questionable accounting or auditing matters.

10. Review and approve Gear's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Gear. All employees of Gear are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Gear without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of Gear will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to Directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation as determined by the Committee.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Committee Chair.

12. Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of the Committee. The Committee may adopt additional policies and procedures as it deems necessary from time to time to fulfill its responsibilities.

November 9, 2016