TORC Oil & Gas Ltd

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2016

Dated March 28, 2017

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DEFINITIONS

Capitalized terms in this Annual Information Form have the meanings set forth below. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

Entities

AcquisitionCo means 1688763 Alberta Ltd.

Board of Directors or **Board** means our board of directors.

CPPIB means the Canada Pension Plan Investment Board.

SaleCos means the private companies acquired by us pursuant to the 2015 February Acquisition.

Shareholders mean holders of our Common Shares.

TORC, **we**, **us**, **our** or the **Corporation** means TORC Oil & Gas Ltd.

Vero means Vero Energy Inc.

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

CSA 51 324 means Staff Notice 51 324 – *Glossary to NI 51 101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

NI 51 101 means National Instrument 51 101– *Standards of Disclosure for Oil and Natural Gas Activities* of the Canadian Securities Administrators.

Sproule means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

Sproule Report means the independent engineering report dated March 1, 2017 and effective December 31, 2016 prepared by Sproule evaluating the oil, NGL and natural gas reserves attributable to all of our properties.

Securities

Common Shares means our common shares, as presently constituted.

Preferred Shares means our first preferred shares issuable in series.

Other

2015 February Acquisition means the indirect acquisition of the 2015 February Acquisition Assets by us through the acquisition of the SaleCos and a general partnership, pursuant to a purchase and sale agreement between us, a general partnership, the vendors of the SaleCos and certain partners of the partnership dated February 25, 2015.

2015 February Acquisition Assets means the light oil producing assets located in southeast Saskatchewan that were acquired by us pursuant to the 2015 February Acquisition.

2015 Significant Acquisition means the acquisition by us of the 2015 Significant Acquisition Assets from the vendor of the 2015 Significant Acquisition Assets for cash consideration of $430 million before purchase price adjustments, pursuant to a purchase and sale agreement between the vendors of the 2015 Significant Acquisition Assets and us dated April 27, 2015.

2015 Significant Acquisition Assets means the light oil assets located in southeast Saskatchewan and southwest Manitoba that were acquired by us pursuant to the 2015 Significant Acquisition.

2015 Significant Acquisition Vendor means the corporate vendor of the 2015 Significant Acquisition Assets.

2015 Swap Transaction means the asset swap of common working interests in certain of our non-operated working interest properties in southeast Saskatchewan which closed on March 31, 2015.

2016 SE Saskatchewan Acquisition means the acquisition by us of the 2016 SE Saskatchewan Acquisition Assets from the vendor of the 2016 SE Saskatchewan Acquisition Assets for cash consideration of $89.5 million before purchase price adjustments, pursuant to a purchase and sale agreement between the vendor of the 2016 SE Saskatchewan Acquisition Assets and us dated July 25, 2016.

2016 SE Saskatchewan Acquisition Assets means the light oil assets located in southeast Saskatchewan that were acquired by us pursuant to the 2016 SE Saskatchewan Acquisition.

2016 Tuck-in Acquisitions means the acquisitions of the 2016 Tuck-in Acquisition Assets by us in the first half of 2016.

2016 Tuck-in Acquisitions Assets means the light oil producing assets located in southeast Saskatchewan that were acquired by us pursuant to the 2016 Tuck-in Acquisitions.

ABCA means the *Business Corporations Act* (Alberta) R.S.A. 2000, c. B 9, as amended, including the regulations promulgated thereunder.

Consolidation means the consolidation of our Common Shares on September 10, 2013 on the basis of one Common Share for every five Pre-Consolidated Shares.

Credit Facility means our $400 million credit facility. See *Capital Structure* for further information on the Credit Facility.

ABBREVIATIONS AND CONVERSIONS

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

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
Bbls/d	barrels per day	MMcf/d	million cubic feet per day
NGLs	natural gas liquids	MMBtu	million British Thermal Units

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

Other

AECO	a 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. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas
BOE/d	barrel of oil equivalent per day
m3	cubic metres
MBOE	1,000 barrels of oil equivalent
MMboe	1,000,000 barrels of oil equivalent
$000s or M$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of our natural gas and petroleum reserves does not represent the fair market value of our reserves.

Caution Respecting BOE

In this Annual Information Form, the abbreviation BOE means barrel of oil equivalent on the basis of 1 Bbl to 6 Mcf of natural gas when converting natural gas to BOEs. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given 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 to 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.**

Definitions

Certain terms used in this Annual Information Form in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this Annual Information Form, but not defined or described, are defined in NI 51-101, CSA 51-324 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA 51-324 or the COGE Handbook.

Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates as follows:

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

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

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

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

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories as follows:

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

- **developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- **developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

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

Interests in Reserves, Production, Wells and Properties

gross means: (a) in relation to our interest in production or reserves, our "company gross reserves", which are our working interest (operating or non-operating) share before deduction of royalties and without including any of our royalty interests; (b) in relation to wells, the total number of wells in which we have an interest; and (c) in relation to properties, the total area of properties in which we have an interest.

net means: (a) in relation to our interest in production or reserves our working interest (operating or non-operating) share after deduction of royalty obligations, plus our royalty interests in production or reserves; (b) in relation to our interest in wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

working interest means the percentage of undivided interest held by us in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives us the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

Description of Exploration and Development Wells and Costs

development costs means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves; (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems.

development well means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

exploration costs means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as **prospecting costs**) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as **geological and geophysical cost**s); (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploratory wells; and (e) costs of drilling exploratory type stratigraphic test wells.

exploration well means a well that is not a development well, a service well or a stratigraphic test well.

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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. More particularly, this Annual Information Form contains forward-looking statements with respect to:

- the anticipated timing of expenditures by us to satisfy our asset retirement obligations;
- the anticipated impact of environmental laws and regulations on us;
- our plans for the development of our proved and probable undeveloped reserves;
- our anticipated land expiries;
- our plans for funding future development costs;
- anticipated future abandonment and reclamation costs;
- our expectations of the means of funding our ongoing environmental obligations;
- income tax estimates and our tax horizon;
- our corporate strategy, focus and plans;
- our dividend policy and dividend funding requirements;
- anticipated share dividend program participation levels;
- our planned capital expenditures and drilling activity in 2017;

- anticipated decline rates;
- the next scheduled review of the borrowing base of our Credit Facility; and
- the anticipated impact of the factors discussed under the heading *Industry Conditions* on us.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

The forward-looking statements are based on certain key expectations and assumptions made by us, including, but not limited to:

- oil and natural gas production levels;
- commodity prices and exchange rates;
- prevailing weather conditions;
- availability of labour, services and equipment;
- timing and amount of capital expenditures;
- general economic and financial market conditions;
- government regulation in the areas of taxation, royalty rates and environmental protection; and
- the success of our exploration and development activities.

Although we believe that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because we can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to:

- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- inability to secure labour, services and equipment on a timely basis or favourable terms;
- competition for, among other things, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- geological, technical, drilling, production and processing problems;
- availability and cost of capital;
- changes in legislation, including changes in tax laws, royalty rates and incentive programs relating to the oil and natural gas industry; and
- the other factors discussed under *Risk Factors*.

The payment and the amount of dividends declared in any month will be subject to the discretion of our Board of Directors and will depend on our Board of Directors' assessment of our outlook for growth, capital expenditure requirements, cash flow, potential acquisition opportunities, debt position and other conditions that our Board of

Directors may consider relevant at such future time. The amount of future cash dividends, if any, may also vary depending on a variety of factors, including fluctuations in commodity prices and differentials, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

NON-GAAP MEASURES

This Annual Information Form contains the term "netback" which does not have a standardized meaning under generally accepted accounting principles in Canada and therefore may not be comparable with the calculation of similar measures by other companies. We use netback to analyze our financial and operating performance. Netback is not intended to represent operating profits nor should it be viewed as an alternative to net earnings or other measures of financial performance calculated in accordance with generally accepted accounting principles in Canada. In this Annual Information Form, netback is determined by deducting royalties, operating expenses and transportation expenses from oil and gas revenue.

TORC OIL & GAS LTD.

General

We are the resulting entity following the completion of the reverse takeover of Vero and subsequent amalgamation with AcquisitionCo and Vero on November 19, 2012 to form "TORC Oil & Gas Ltd.". See *Development of Our Business*.

Vero was initially formed on November 2, 2005 upon the amalgamation of Vero Energy Inc. and its then wholly-owned subsidiary, Vero Finance Corp. under the ABCA. On January 1, 2010 Vero amalgamated with its then wholly-owned subsidiary, Vero Oil and Gas Ltd.

1525893 Alberta Ltd. was incorporated on March 23, 2010 under the ABCA. On December 15, 2010, we filed articles of amendment changing our name from 1525893 Alberta Ltd. to "TORC Oil & Gas Ltd.". On the same day, we amended our articles to remove: (i) certain restrictions upon invitations to the public to subscribe for our shares; and (ii) restrictions limiting the number of shareholders, exclusive of employees, to less than 50 shareholders. On January 24, 2011, we filed articles of amendment to remove certain restrictions on the transfer of our shares.

On May 1, 2011, we amalgamated with our then wholly-owned subsidiary, Shale Exploration Ltd., with the amalgamated corporation continuing under the name "TORC Oil & Gas Ltd.".

On November 19, 2012, we amalgamated with AcquisitionCo and Vero pursuant to a plan of arrangement under the ABCA, with the amalgamated corporation continuing under the name "TORC Oil & Gas Ltd.".

On September 10, 2013, we filed articles of amendment to effect the Consolidation.

On February 25, 2015, the SaleCos were amalgamated into us, with the amalgamated corporation continuing under the name "TORC Oil & Gas Ltd.".

Head Office and Registered Office

Our head office is located at 1800, 525 – 8th Avenue S.W., Calgary, Alberta. Our registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta.

Stock Exchange and Reporting Issuer Status

Our Common Shares are listed for trading on the Toronto Stock Exchange under the symbol "TOG". We are a reporting issuer in each of the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland.

Intercorporate Relationships

We have no material subsidiaries.

DEVELOPMENT OF OUR BUSINESS

History and Development

The following is a summary of how our business has developed over the last three years.

Developments in 2014

In 2014, we entered into a series of strategic acquisitions for an aggregate acquisition price of approximately $138 million. Through fourteen separate transactions, we added more than 1,500 BOE/d (>85% light oil and liquids) in both our west central Alberta Cardium and southeast Saskatchewan core areas. The acquisitions included working interest top-ups in a number of our key producing properties, as well as strategic offsetting acreage providing additional development light oil drilling locations.

The Credit Facility was increased to $375 million on April 23, 2014.

On October 29, 2014, we completed a non-brokered private placement of 1.4 million Common Shares issued as "flow through" shares under the *Income Tax Act* (Canada) for gross proceeds of $19.7 million.

Effective October 30, 2014, we expanded our Credit Facility availability to $425 million from $375 million.

Developments in 2015

On February 25, 2015 we completed the 2015 February Acquisition pursuant to which we acquired the 2015 February Acquisition Assets which consisted of approximately 1,550 BOE/d of production (94% light oil and liquids) with an average expected decline rate of approximately 20%. Total consideration for the 2015 February Acquisition on announcement was approximately $128 million, before adjustments, payable through the issuance of 16.0 million Common Shares.

On March 31, 2015, we completed the 2015 Swap Transaction pursuant to which we sold our interests in certain non-operated properties in southeast Saskatchewan in exchange for other properties, also located in southeast Saskatchewan. The 2015 Swap Transaction involved approximately 500 BOE/d of production with similar amounts of production and reserves being swapped for minimal net gain or loss. The 2015 Swap Transaction consolidated our assets in southeast Saskatchewan and increased the amount of production operated by us in the area.

On April 27, 2015, we entered into a purchase and sale agreement pursuant to which we agreed to purchase the 2015 Significant Acquisition Assets for cash consideration of $430 million before purchase price adjustments. The 2015 Significant Acquisition Assets included 4,750 BOE/d of low decline, high netback, light oil producing assets in southeast Saskatchewan and Manitoba and ownership of freehold mineral title on more than 80 net sections of land in southeast Saskatchewan. On the same day, we entered into a bought deal agreement with a syndicate of underwriters with respect to the public offering of 28,520,000 subscription receipts at a subscription price of $10.10 for aggregate gross proceeds of approximately $288 million which includes the exercise in full of the over-allotment option granted to the underwriters, and an agreement with CPPIB for the private placement of 14,850,000 subscription receipts to CPPIB at a subscription price of $10.10 for aggregate gross proceeds of approximately $150 million. These offerings were completed on May 20, 2015 and the proceeds were held in escrow pending completion of the 2015 Significant Acquisition.

On June 15, 2015 we completed the 2015 Significant Acquisition. In connection with the completion of the 2015 Significant Acquisition, the subscription receipts issued by us were converted into Common Shares on a one for one basis and the proceeds from the subscription receipt financings were released from escrow to partially fund the purchase price of the 2015 Significant Acquisition. The balance of the purchase price was funded through a draw on our Credit Facility. Following the closing of the 2015 Significant Acquisition, our Credit Facility was increased from $425 million to $550 million.

On October 31, 2015, the Credit Facility was renewed and we elected to reduce the facility to $450 million, comprised of a $55 million operating facility and a $395 million syndicated facility.

Developments in 2016

On February 16, 2016, we announced that our Board had approved a monthly dividend of $0.02 per Common Share, to be paid on March 15, 2016 to Shareholders of record on February 29, 2016. The declared dividend was a reduction from the previous monthly level of $0.045 per Common Share as a result of continued volatility and uncertainty in commodity prices.

On May 4, 2016, the Credit Facility was renewed at $400 million, comprised of a $55 million operating facility and a $345 million syndicated facility.

On July 25, 2016, we entered into a purchase and sale agreement pursuant to which we agreed to purchase the 2016 SE Saskatchewan Acquisition Assets for cash consideration of approximately $89.5 million, prior to closing adjustments. The 2016 SE Saskatchewan Acquisition Assets included 1,120 BOE/d (approximately 95% light oil and NGLs) of low decline, high netback, light oil producing assets.

On the same day, we entered into a bought deal agreement with a syndicate of underwriters with respect to the public offering of 12,236,000 Common Shares at a price of $7.05 per Common Share for total gross proceeds of approximately $86.3 million, which includes the exercise in full of the over-allotment option granted to the underwriters, and an agreement with CPPIB for the private placement of 3,546,100 Common Shares to CPPIB at a subscription price of $7.05 per Common Share for total gross proceeds of approximately $25 million. These offerings were completed on August 16, 2016.

In the first half of 2016, we also completed the Tuck-in Acquisitions for total cash consideration of approximately $6 million. The 2016 Tuck-in Acquisitions Assets included approximately 80 BOE/d (approximately 98% light oil) of production and added numerous drilling locations, primarily in southeast Saskatchewan and also in our Cardium core area.

On September 1, 2016, we completed the 2016 SE Saskatchewan Acquisition.

Recent Developments

On December 14, 2016, our Board approved our 2017 capital budget of $130 million. The capital program in 2017 will be focused on light oil development projects, with the majority of the capital directed to drilling, completions and tie-ins (approximately 80%) with the remainder allocated to operational and facility optimization to maximize production efficiency. The capital program will be concentrated on our primary core areas in southeast Saskatchewan, focused on both conventional opportunities and the Torquay/Three Forks play, as well as the Cardium play in central Alberta.

We have the operational flexibility to adjust our 2017 capital budget to continue to prudently protect our financial flexibility in a sustained low price environment but also to take advantage of a potentially increasing commodity price environment.

On the same day, we announced that beginning with the January 2017 dividend to be paid in February 2017, we will eliminate the discount associated with our share dividend plan.

Significant Acquisitions

We have not completed any significant acquisitions during our most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

DESCRIPTION OF OUR BUSINESS

Corporate Strategy

We are an intermediate light oil producer paying dividends while also pursuing cost-effective per share growth in reserves, production and funds flow in western Canada.

Our overall corporate strategy is to provide cost-effective per share growth in reserves, production, and cash flow combined with a sustainable monthly dividend by:

- focusing on high quality, light oil weighted plays;

- positioning us for growth through exposure to light oil assets utilizing an integrated strategy of resource capture, delineation and development;

- maintaining a strong balance sheet; and
- attracting and retaining top quality technical and corporate staff with proven track records.

Ongoing Acquisitions and Disposition Activities

Our Board may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the strategy discussed above based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life, strategic importance and asset quality. See *Industry Conditions* and *Risk Factors*.

Competition

The oil and natural gas industry is competitive in all its phases. We compete with numerous other participants in the acquisition, exploration and development of oil and natural gas assets and in the marketing of oil and natural gas. Our competitors include resource companies which may have greater financial resources, staff and facilities than us. We believe that our competitive position is, on the whole, equivalent to that of other oil and natural gas producers of similar size and at a similar stage of development. See *Industry Conditions* and *Risk Factors*.

Environmental Policies

We support environmental protection and employee health and safety by integrating the essential principles and practices through our environmental management systems and employee occupational health and safety programs. We promote safety and environmental awareness and protection through the implementation and communication of our environmental management and employee occupational health and safety programs, policies and procedures. Committee structures are established in our operations which are designed to allow for employee participation and development of policies and programs which provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

We develop emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which we operate in order to effectively respond to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. We conduct audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist in achieving the objectives of the described policies and programs.

We also face environmental, health and safety risks in the normal course of our operations due to the handling and storage of hazardous substances. Our environmental and occupational health and safety management systems are designed to manage such risks in our business and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits. See *Industry Conditions* and *Risk Factors*.

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. Unexpected adverse weather conditions, such as flooding or prolonged break-up, can have a significant negative impact on operations and costs. See *Industry Conditions* and *Risk Factors*.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2017 by the renegotiation or termination of contracts.

Personnel

As at December 31, 2016, we had 58 head office employees and 20 field employees.

PRINCIPAL PROPERTIES

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2016.

Information in respect of current production is average production, net to our working interest, except where otherwise indicated. **Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.**

West Central Alberta Cardium

Our West Central Alberta Cardium properties consist of an average working interest of approximately 70% in 207,916 gross (146,474 net) acres of land in the Brazeau, Carrot Creek, Kaybob, Pembina, Pine Creek and Rosevear areas on the Cardium trend in west central Alberta, all of which are located approximately 150 to 250 kilometres west of Edmonton. In 2016, we targeted the Cardium formation, drilling a total of 10 gross (9.7 net) oil wells.

The properties include 144 gross (113 net) producing light oil wells and 22 gross (10 net) producing gas wells. We operate two major oil production facilities in the Kaybob and Pembina fields. Average daily production from the properties for the year ended December 31, 2016 was 4,891 BOE/d and was weighted 64% to light crude oil and NGLs. As at December 31, 2016, the Sproule Report attributed proved plus probable reserves of 19,648 Mbbls of light oil and NGLs and 79,010 MMcf of natural gas to the Cardium properties.

Monarch, Alberta

Our Monarch property consists of an average working interest of approximately 96% in 74,026 gross (71,242 net) acres of land in the Alberta Bakken petroleum system in southern Alberta, located approximately 150 to 180 kilometres southeast of Calgary. In 2016, there were no wells drilled on the Monarch property.

The property includes 18 gross (18 net) producing light oil wells. We have no major facilities in the area. Average daily production from the property for the year ended December 31, 2016 was 554 BOE/d and was weighted 100% to light crude oil. As at December 31, 2016, the Sproule Report attributed proved plus probable reserves of 2,913 Mbbls of light oil and no NGL or natural gas reserves to the Monarch property.

Southeast Saskatchewan and Manitoba

Our southeast Saskatchewan and Manitoba assets consist of an average working interest of approximately 72% in 467,707 gross (336,344 net) acres of land primarily focused on conventional Mississippian light oil plays and the emerging Torquay/Three Forks light oil resource play. In 2016, we targeted the Frobisher, Midale, and Ratcliffe formations in drilling a total of 21 gross (19.0 net) conventional light oil wells. Additionally in 2016, we targeted the Torquay/Three Forks formation in drilling a total of 8 gross (7.0 net) unconventional light oil wells.

The southeast Saskatchewan and Manitoba assets include 1,680 gross (906 net) producing light oil wells. Major facilities include operated oil production facilities at Browning, Steelman, Wapella and Willmar. Average daily production from the properties for the year ended December 31, 2016 was 13,209 BOE/d and was weighted 95% to light crude oil. As at December 31, 2016, the Sproule Report attributed proved plus probable reserves of 60,222 Mbbls of light oil and NGLs and 21,743 MMcf of natural gas to the southeast Saskatchewan and Manitoba properties.

STATEMENT OF RESERVES DATA

The statement of reserves data and other oil and natural gas information set forth below is dated March 1, 2017. The statement is effective as of December 31, 2016 and the preparation date of the statement is March 1, 2017. The Report on Reserves Data By Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 and the Report of Management and Directors On Oil and Gas Disclosure in Form 51-101F3 are attached as Schedules "B" and "C" to this Annual Information Form.

In accordance with NI 51-101, Sproule prepared the Sproule Report. The Sproule Report evaluated, as at December 31, 2016, all of our oil, NGL and natural gas reserves.

The tables below are a summary of our crude oil, NGLs and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment and reclamation costs. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided.

We determined the future net revenue and present value of future net revenue after income tax expenses by utilizing Sproule's before income tax future net revenue and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different. Our financial statements for the year ended December 31, 2016 should be consulted for additional information regarding our taxes.

The Sproule Report is based on certain factual data supplied by us and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by us to Sproule. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data (Forecast Prices and Costs)

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

	RESERVES							
	GROSS RESERVES				NET RESERVES			
RESERVE CATEGORY	**Light and Medium Crude Oil (Mbbls)**	**Natural Gas Liquids (Mbbls)**	**Conven-tional Natural Gas (MMcf)**	**Total BOE (MBOE)**	**Light and Medium Crude Oil (Mbbls)**	**Natural Gas Liquids (Mbbls)**	**Conven-tional Natural Gas (MMcf)**	**Total BOE (MBOE)**
PROVED:								
Developed Producing	32,852	2,115	35,354	40,859	29,130	1,769	31,060	36,076
Developed Non-Producing	1,132	112	2,192	1,609	1,011	92	1,930	1,424
Undeveloped	16,663	1,060	25,096	21,905	15,054	926	22,705	19,674
TOTAL PROVED	50,646	3,286	62,641	64,373	45,195	2,787	55,695	57,264
PROBABLE	27,073	1,777	38,111	35,202	23,600	1,496	33,858	30,738
TOTAL PROVED PLUS PROBABLE	77,719	5,063	100,753	99,574	68,794	4,283	89,554	88,002

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)					
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**Unit Value Before Income Tax Discounted at 10% per Year(1) ($/BOE)**
PROVED:						
Developed Producing	1,219,033	968,965	802,972	687,838	604,024	22.26
Developed Non-Producing	36,404	28,653	23,119	19,118	16,144	16.23
Undeveloped	502,584	343,245	240,918	172,478	124,740	12.19
TOTAL PROVED	1,758,022	1,340,862	1,067,010	879,434	744,908	18.63
PROBABLE	1,189,736	725,300	491,821	358,362	274,483	16.00
TOTAL PROVED PLUS PROBABLE	2,947,757	2,066,163	1,558,830	1,237,796	1,019,391	17.71

Note:

(1) Unit values are based on net volumes.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,219,033	968,965	802,972	687,838	604,024
Developed Non-Producing	36,404	28,653	23,119	19,118	16,144
Undeveloped	430,359	298,362	211,931	153,132	111,460
TOTAL PROVED	1,685,796	1,295,980	1,038,022	860,088	731,628
PROBABLE	877,565	530,333	358,866	261,992	201,555
TOTAL PROVED PLUS PROBABLE	2,563,361	1,826,313	1,396,888	1,122,080	933,183

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS (1)(2)

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES ($000s)	INCOME TAX EXPENSES ($000s)	FUTURE NET REVENUE AFTER INCOME TAX EXPENSES ($000s)
Total Proved	4,485,130	584,087	1,608,747	408,585	125,689	1,758,022	72,226	1,685,796
Total Proved plus Probable	7,263,586	986,571	2,556,980	617,647	154,631	2,947,757	384,397	2,563,361

Notes:

(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties, mineral tax and Saskatchewan Capital Surtax.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE (1) ($/Bbl or $/Mcf)
Proved	Light and Medium Crude Oil (2)	1,065,658	18.83
	Conventional Natural Gas (3)	3,311	6.11
	Corporate Lease Operating Cost Adjustment (4)	(1,960)	
	Total	1,067,010	
Proved plus Probable	Light and Medium Crude Oil (2)	1,552,060	17.94
	Conventional Natural Gas (3)	7,577	5.68
	Corporate Lease Operating Cost Adjustment (4)	(806)	
	Total	1,558,830	

Notes:

(1) Unit values are based on net reserve volumes.

(2) Including solution gas and other by-products.
(3) Including by-products but excluding solution gas and by-products from oil wells.
(4) Represents the discounted net present value of lease operating expenses associated with suspended wells with no reserves assigned.

Pricing Assumptions – Forecast Prices and Costs

Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2016 in the Sproule Report in estimating reserves data using forecast prices and costs. Benchmark weighted average historical prices for 2016 are also reflected in the table below.

SUMMARY OF WEIGHTED AVERAGE HISTORICAL PRICES FOR 2016 AND PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS (1)

	MEDIUM AND LIGHT CRUDE OIL			NATURAL GAS	NATURAL GAS LIQUIDS				
YEAR	WTI Cushing Oklahoma 40° API ($US/Bbl)	Edmonton Par Price 40° API ($/Bbl)	Cromer LSB 35° API ($/Bbl)	AECO-C Spot ($/MMBtu)	Edmonton Butane ($/Bbl)	Pentanes Plus ($/Bbl)	Capital Cost Inflation Rate (%/Yr) (2)	Operating Cost Inflation Rate (%/Yr) (2)	Exchange Rate ($US/$) (3)
2016 Actual	43.32	52.80	50.77	2.18	34.42	55.71	-3.3%	1.6%	0.755
2017	55.00	65.58	64.58	3.44	47.60	67.95	0.0%	0.0%	0.780
2018	65.00	74.51	73.51	3.27	55.49	75.61	2.0%	2.0%	0.820
2019	70.00	78.24	77.24	3.22	57.65	78.82	2.0%	2.0%	0.850
2020	71.40	80.64	79.64	3.91	58.80	80.47	2.0%	2.0%	0.850
2021	72.83	82.25	81.25	4.00	59.98	82.15	2.0%	2.0%	0.850
2022	74.28	83.90	82.90	4.10	61.18	83.86	2.0%	2.0%	0.850
2023	75.77	85.58	84.58	4.19	62.40	85.61	2.0%	2.0%	0.850
2024	77.29	87.29	86.29	4.29	63.65	87.39	2.0%	2.0%	0.850
2025	78.83	89.03	88.03	4.40	64.92	89.21	2.0%	2.0%	0.850
2026	80.41	90.81	89.81	4.50	66.22	91.07	2.0%	2.0%	0.850
2027	82.02	92.63	91.63	4.61	67.54	92.96	2.0%	2.0%	0.850

Escalated at 2.0% per year thereafter

Notes:

(1) As at January 1, 2017.
(2) Inflation rate for capital and operating costs.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of our gross reserves as at December 31, 2016, derived from the Sproule Report using forecast prices and cost estimates, reconciled to our gross reserves as at December 31, 2015.

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

PROVED RESERVES	LIGHT AND MEDIUM CRUDE OIL	NATURAL GAS LIQUIDS	CONVENTIONAL NATURAL GAS	TOTAL OIL EQUIVALENT
	(Mbbls)	(Mbbls)	(MMcf)	(MBOE)
December 31, 2015	47,097	3,067	58,296	59,880
Extensions	4,550	54	1,191	4,802
Infill Drilling	-	-	-	-
Improved Recovery	132	-	34	138
Technical Revisions	1,571	425	8,931	3,485
Discoveries	-	-	-	-
Acquisitions [1]	4,759	76	2,121	5,188
Dispositions	(16)	(1)	(20)	(20)
Economic Factors	(1,742)	(113)	(2,513)	(2,274)
Production	(5,705)	(222)	(5,401)	(6,827)
December 31, 2016	50,646	3,286	62,641	64,373

Note:

(1) The acquisitions amount is the estimate of reserves at December 31, 2016 plus any production since the acquisition dates.

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

PROBABLE RESERVES	LIGHT AND MEDIUM CRUDE OIL	NATURAL GAS LIQUIDS	CONVENTIONAL NATURAL GAS	TOTAL OIL EQUIVALENT
	(Mbbls)	(Mbbls)	(MMcf)	(MBOE)
December 31, 2015	23,497	1,581	33,190	30,610
Extensions	2,775	34	633	2,915
Infill Drilling	61	-	-	61
Improved Recovery	282	-	46	290
Technical Revisions	(782)	143	3,427	(68)
Discoveries	-	-	-	-
Acquisitions [1]	1,686	34	1,050	1,895
Dispositions	(15)	(1)	(24)	(20)
Economic Factors	(432)	(14)	(210)	(481)
Production	-	-	-	-
December 31, 2016	27,073	1,777	38,112	35,202

Note:

(1) The acquisitions amount is the estimate of reserves at December 31, 2016 plus any production since the acquisition dates.

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

PROVED PLUS PROBABLE RESERVES	LIGHT AND MEDIUM CRUDE OIL (Mbbls)	NATURAL GAS LIQUIDS (Mbbls)	CONVENTIONAL NATURAL GAS (MMcf)	TOTAL OIL EQUIVALENT (MBOE)
December 31, 2015	70,594	4,648	91,486	90,490
Extensions	7,325	88	1,825	7,717
Infill Drilling	61	-	-	61
Improved Recovery	415	-	80	428
Technical Revisions	790	568	12,358	3,417
Discoveries	-	-	-	-
Acquisitions (1)	6,445	110	3,171	7,083
Dispositions	(31)	(2)	(43)	(40)
Economic Factors	(2,174)	(127)	(2,723)	(2,755)
Production	(5,705)	(222)	(5,401)	(6,827)
December 31, 2016	77,719	5,063	100,753	99,574

Note:

(1) The acquisitions amount is the estimate of reserves at December 31, 2016 plus any production since the acquisition dates.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

We currently plan to pursue the development of our proved and probable undeveloped reserves within the next two years through ordinary course capital expenditures. In some cases, it will take longer than two years to develop these reserves; however, we expect that the large majority of our booked undeveloped projects will be completed within a two year time frame. There are a number of factors that could result in delayed or cancelled development, including the following: (i) existence of higher priority expenditures; (ii) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (iii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iv) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (v) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (vi) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see *Risk Factors*.

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of gross proved undeveloped reserves that were attributed in each of the most recent three financial years.

Year	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2014	2,486	9,625	1,967	17,488	78	701
2015	940	14,749	2,018	24,983	87	1,101
2016	4,267	16,663	1,925	25,096	72	1,060

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. Sproule has assigned 21.9 MMboe of gross proved undeveloped reserves in the Sproule Report with $404.3 million of associated undiscounted future development capital, of which $233.8 million is forecast to be spent in the first two years.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of gross probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Crude Oil (Mbbls)		Conventional Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2014	2,033	7,912	1,727	16,962	71	673
2015	1,401	13,520	1,508	23,948	68	1,014
2016	3,196	15,441	1,225	27,832	50	1,164

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. Sproule has assigned 21.2 MMboe of gross probable undeveloped reserves in the Sproule Report with $207.5 million of associated undiscounted future development capital, of which $87.2 million is forecast to be spent in the first two years.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in future commodity prices relative to the forecasts provided under *Pricing Assumptions* above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Our reserves can also be affected significantly by fluctuations in capital expenditures, operating costs, royalty regimes, abandonment and reclamation costs and well performance that are beyond our control. See *Risk Factors*.

Abandonment and Reclamation Costs

Our overall abandonment and reclamation costs are based on well bore abandonment and reclamation costs and liability issues such as flare pit remediation, facility decommissioning, and remediation and reclamation costs. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing well bores for reactivation, recompletion or sale and conduct systematic abandonment programs for those well bores that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs.

Sproule included well abandonment and reclamation costs for 1,317 net (2,056 gross) wells and locations under the proved reserves category of $125.7 million undiscounted ($20.1 million discounted at 10%) in the Sproule Report, $0.3 million of which is expected to be incurred from 2017 to 2021. Sproule included well abandonment and reclamation costs for 1,421 net (2,196 gross) wells and locations under the total proved plus probable reserves category of $154.6 million undiscounted ($16.6 million discounted at 10%) in the Sproule Report, $0.4 million of which is expected to be incurred from 2017 to 2021.

The above well abandonment and reclamation costs from the Sproule Report include $25.7 million undiscounted ($2.7 million discounted at 10%) for 224 net (289 gross) future proved development locations and $43.0 million undiscounted ($2.7 million discounted at 10%) for 338 net (442 gross) future proved plus probable development locations.

The future net revenues disclosed in this Annual Information Form based on the Sproule Report do not contain an allowance for salvage, abandonment and reclamation costs for surface leases, facilities and pipelines nor do they include abandonment and disconnect cost for wells to which reserves were not assigned (i.e. shut-in, suspended, injection and/or service wells).

We estimate an additional $214.0 million of undiscounted abandonment and reclamation costs for wells and facilities not included in the Sproule Report. We will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of funds from operations.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the Sproule Report of future net revenue attributable to our proved reserves and proved plus probable reserves (using forecast prices and costs).

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2017	109,739	150,764
2018	127,175	173,376
2019	132,040	183,701
2020	39,482	109,657
2021 & thereafter	149	149
TOTAL UNDISCOUNTED	408,585	617,647

We have three sources of funding available to finance future development costs: internally generated funds from operations, debt financing and equity financing. We currently expect to fund future development costs primarily through funds from operations, but may rely, to some extent, on debt financing by drawing down on our Credit Facility or equity financing by issuing additional Common Shares depending on prevailing commodity prices, market conditions, the desirability of accelerating our capital expenditure program and the availability of financing on favourable terms.

Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. The cost of the debt component for funding future development costs is expected to be minimal and to not materially impact the disclosed reserves or future net revenue.

OTHER OIL AND NATURAL GAS INFORMATION

Oil and Natural Gas Wells

The following table sets forth the number and status of our wells effective December 31, 2016.

	PRODUCING WELLS				NON-PRODUCING WELLS			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	162	131	21	9	127	106	11	5
Saskatchewan	1,459	859	-	-	363	269	-	-
Manitoba	37	32	-	-	17	17	-	-
TOTAL	1,658	1,022	21	9	507	392	11	5

Of the non-producing wells, 3 gross (2.6 net) wells drilled in 2016 were capable of production and had reserves assigned to them. As of the date of this Annual Information Form, these wells have been placed on production.

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2016, the gross and net acres of undeveloped properties in which we had an interest and also the number of net acres for which our rights to explore, develop or exploit could expire within one year.

	GROSS ACRES	NET ACRES	NET ACRES EXPIRING WITHIN ONE YEAR
Alberta	234,586	181,432	49,285
Saskatchewan	219,464	164,653	35,462
Manitoba	4,041	4,041	3,188
TOTAL	458,092	350,126	87,935

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. However, our decision to develop our properties with no attributed reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs and royalty regimes all of which are beyond our control. There are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. See *Significant Factors and Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs* and *Risk Factors*.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us from time to time to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties.

For details of our material commitments to sell natural gas and crude oil that were outstanding at December 31, 2016 see Note 21 to our 2016 annual audited consolidated financial statements, which is incorporated herein by reference.

Tax Horizon

Based on Sproule production forecasts, planned capital expenditures and the forecast commodity pricing employed in the Sproule Report, we estimate that we will not be required to pay current income taxes until at least 2023.

Costs Incurred

The following table summarizes capital expenditures incurred by us during the year ended December 31, 2016.

	PROPERTY ACQUISITION COSTS			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
TOTAL (millions)	$95.0	$Nil	$Nil	$82.3

Drilling Activity

The following table sets forth the gross and net development wells drilled by us during the year ended December 31, 2016. All of these wells were drilled in Canada. We did not drill any exploration wells during the year ended December 31, 2016.

	Gross	Net
Light and Medium Crude Oil	39	35.7
Natural Gas	-	-
Service	1	1.0
Stratigraphic Test	-	-
Dry	-	-
TOTAL	40	36.7

Planned Capital Expenditures

In December 2016 we announced our planned capital expenditure budget of $130 million for 2017 which is primarily focused on light oil development projects with the majority of the capital directed to drilling, completions and tie-ins (greater than 80%) with the remainder allocated to operational and facility optimization to maximize production efficiency. This capital budget includes drilling 38 gross (31.5 net) conventional wells in southeast Saskatchewan, 15 gross (12.5 net) wells in to the Torquay/Three Forks, and 12 gross (10.7 net) wells across our land position in the Cardium.

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Sproule Report for 2017 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light and Medium Crude Oil (Bbls/d)	NGLs (Bbls/d)	Conventional Natural Gas (Mcf/d)	Total Oil Equivalent (BOE/d)	Percentage (%)
PROVED					
Alberta					
Cardium	3,212	501	12,214	5,748	28
Monarch	427	-	-	427	2
Saskatchewan	12,517	378	4,785	13,693	67
Manitoba	624	-	-	624	3
TOTAL PROVED	16,780	879	16,999	20,492	100
PROVED PLUS PROBABLE					
Alberta					
Cardium	3,759	583	14,201	6,709	29
Monarch	476	-	-	476	2
Saskatchewan	13,697	407	5,164	14,965	66
Manitoba	756	-	-	756	3
TOTAL PROVED PLUS PROBABLE	18,688	990	19,365	22,906	100

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2016, certain information in respect of our production, product prices received, royalties paid, operating expenses and resulting netback.

	Quarter Ended 2016				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2016**
Average Daily Production (1)					
Light and Medium Crude Oil (Bbls/d)	15,334	15,255	15,314	16,440	15,588
Natural Gas Liquids (Bbls/d)	462	542	781	640	607
Conventional Natural Gas (MMcf/d)	14,197	14,446	15,124	15,245	14,755
Combined (BOE/d)	18,162	18,205	18,616	19,621	18,654
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	35.44	48.44	50.63	56.42	47.92
Natural Gas Liquids ($/Bbl)	15.90	14.69	11.23	21.46	15.60
Conventional Natural Gas ($/Mcf)	1.54	1.21	2.03	2.68	1.88
Combined ($/BOE)	31.53	41.98	43.77	50.05	42.04
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	6.21	8.80	8.99	8.37	8.10
Natural Gas Liquids ($/Bbl)	2.79	2.67	2.00	3.18	2.63
Conventional Natural Gas ($/Mcf)	0.27	0.22	0.36	0.40	0.32
Combined ($/BOE)	5.53	7.63	7.77	7.43	7.10
Production Costs (2)(3)					
Light and Medium Crude Oil ($/Bbl)	16.51	16.91	16.75	13.15	15.77
Natural Gas Liquids ($/Bbl)	7.41	5.13	3.72	5.00	5.13
Conventional Natural Gas ($/Mcf)	0.72	0.42	0.67	0.63	0.62
Combined ($/BOE)	14.69	14.66	14.48	11.67	13.83
Netback Received (4)					
Light and Medium Crude Oil ($/Bbl)	12.72	22.73	24.89	34.90	24.05
Natural Gas Liquids ($/Bbl)	5.70	6.89	5.51	13.28	7.83
Conventional Natural Gas ($/Mcf)	0.55	0.57	1.00	1.65	0.94
Combined ($/BOE)	11.31	19.69	21.52	30.95	21.11

Notes:

(1) Before the deduction of royalties.

(2) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between product types.

(3) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.

(4) Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received. See *Non-GAAP Measures*.

Production Volume by Field

The following table indicates the average daily net production from our fields for the year ended December 31, 2016.

	Light and Medium Crude Oil (Bbls/d)	**NGLs (Bbls/d)**	**Conventional Natural Gas (Mcf/d)**	**Total Oil Equivalent (BOE/d)**	**Percentage (%)**
Alberta					
Cardium	2,835	298	10,550	4,891	26
Monarch	554	-	-	554	3
Saskatchewan	11,490	309	4,205	12,500	67
Manitoba	709	-	-	709	4
TOTAL	15,588	607	14,755	18,654	100

CAPITAL STRUCTURE

Credit Facility

Our Credit Facility is a $400 million borrowing base credit facility, comprised of a $55 million operating facility from our operating lender (the "**Operating Facility**") and a $345 million syndicated facility with a syndicate of banks (the "**Syndicated Facility**"). Advances under the Credit Facility are available by way of direct advances, bankers' acceptances and standby letters of credit/guarantees. Direct advances bear interest at the prime rate, U.S. base rate or Libor rate, as applicable, plus a margin which is dependent on our debt to trailing funds flow ratio. The bankers' acceptances bear interest at the applicable bankers' acceptance rate plus a stamping fee, based on our debt to trailing funds flow ratio.

Both the Syndicated Facility and the Operating Facility are available on a revolving basis until April 27, 2017. On or before April 27, 2017, at our request and subject to the approval of the lending syndicate, the Credit Facility may be extended for an additional 364 day period. In the event of non-extension, the undrawn portion of the Credit Facility will be cancelled and the amount outstanding will convert to a 364 day non-revolving term facility with repayment of the Credit Facility due on April 28, 2018. The Credit Facility is secured by a fixed and floating charge debenture on all of our assets.

The borrowing base of our Credit Facility is primarily based on reserves and commodity prices estimated by the lenders. The borrowing base of our Credit Facility is subject to review and redetermination by the lenders on a semi-annual basis and in the event of a change in our borrowing base properties (including due to a disposition of assets beyond certain defined limits or a change which results in a material adverse effect, as determined by the lenders). In the normal course, the borrowing base is next scheduled for review on or before April 27, 2017 and there can be no assurance that the current borrowing base level will be maintained. See *Risk Factors – Credit Facility Arrangements*.

Pursuant to the terms of the Credit Facility, we are permitted to pay dividends provided that there is no borrowing base shortfall, default or event of default under the Credit Facility and no default or event of default could reasonably be expected to result from such payment.

Share Capital

We are authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares. A description of our share capital is set forth below. For a completed description of our share capital, reference should be made to our Articles, a copy of which has been filed on our SEDAR profile at *www.sedar.com*.

Common Shares

The Common Shares have the following rights, privileges, restrictions and conditions:

Voting Rights: Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of shares other than the Common Shares).

Dividends: Holders of Common Shares are entitled to receive dividends as and when declared by the Board of Directors on the Common Shares as a class, subject to the prior satisfaction of all preferential rights to dividends attached to other classes of shares ranking in priority to the Common Shares in respect of dividends.

Ranking: In the event of any liquidation, dissolution or winding-up of us, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all other classes of Shares ranking in priority to the Common Shares in respect of return of capital on dissolution, holders of Common Shares are entitled to share rateably, together with the holders of shares of any other class of shares ranking equally with the Common Shares, in respect of a return of capital on dissolution, in such of our assets as are available for distribution.

If our Board of Directors declare a dividend on the Common Shares payable in whole or in part in fully paid and non-assessable Common Shares (the portion of the dividend payable in Common Shares referred to as a "**stock dividend**"), the following provisions shall apply:

(a) unless otherwise determined by the Board of Directors in respect of a particular stock dividend: (i) the number of Common Shares (which shall include any fractional Common Shares) to be issued in satisfaction of the stock dividend shall be determined by dividing (A) the dollar amount of the particular stock dividend, by (B) the "Average Market Price" of a Common Share on the Toronto Stock Exchange, with the "Average Market Price" calculated by dividing the total value of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) by the total volume of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) over the five trading day period immediately prior to the payment date of the applicable stock dividend on the Common Shares; and (ii) the value of a Common Share to be issued for the purposes of each stock dividend declared by the Board of Directors shall be deemed to be the Average Market Price of a Common Share;

(b) to the extent that any stock dividend paid on the Common Shares represents one or more whole Common Shares payable to a registered holder of Common Shares, such whole Common Shares shall be registered in the name of such holder. Common Shares representing in the aggregate all of the fractions amounting to less than one whole Common Share which might otherwise have been payable to registered holders of Common Shares by reason of such stock dividend shall be issued to our transfer agent as the agent of such registered holders of Common Shares. Our transfer agent shall credit to an account for each such registered holder all fractions of a Common Share amounting to less than one whole share issued by us by way of stock dividends in respect of the Common Shares registered in the name of such holder. From time to time, when the fractional interests in a Common Share held by our transfer agent for the account of any registered holder of Common Shares are equal to or exceed in the aggregate one additional whole Common Share, the transfer agent shall cause such additional whole Common Share to be registered in the name of such registered holder and thereupon only the excess fractional interest, if any, will continue to be held by the transfer agent for the account of such registered holder. Common Shares held by the transfer agent representing fractional interests shall not be voted;

(c) if at any time we have reason to believe that tax should be withheld and remitted to a taxation authority in respect of any stock dividend paid or payable to a Shareholder in Common Shares, we have the right to sell, or to require our transfer agent in each case as agent of such Shareholder, to sell all or any part of the Common Shares or any fraction thereof so issued to such holder in payment of that stock dividend or one or more subsequent stock dividends through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, and to cause its transfer agent to remit the cash proceeds from such sale to such taxation authority (rather than such holder) in payment of such tax to be withheld. This right of sale may be exercised by notice given by us to such holder and to us or our transfer agent stating the name of the holder, the number of Common Shares to be sold and the amount of the tax which we have reason to believe should be withheld. Upon receipt of such notice the transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and TORC or its transfer agent as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and deliver the proceeds therefrom to the applicable taxation authority on behalf of us. Any balance of the cash sale proceeds not remitted by us in payment of the tax to be withheld shall be payable to the holder whose Common Shares were so sold by the transfer agent;

(d) if at any time we shall have reason to believe that the payment of a stock dividend to any holder who is resident in or otherwise subject to the laws of a jurisdiction outside Canada might contravene the laws or regulations of such jurisdiction, or could subject us to any penalty thereunder or any legal or regulatory requirements not otherwise applicable to us, we shall have the right to sell, or to require our transfer agent in each case, as agent of such Shareholder, to sell through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, the Common Shares or any fraction thereof so issued and to cause our transfer agent to pay the cash proceeds from such sale to such holder. The right of sale shall be exercised in the manner provided in subparagraph (c) above except that in the notice there shall be stated, instead of the amount of the tax to be withheld, the nature of the law or regulation which might be contravened or which might subject us to any penalty or legal or regulatory requirement. Upon receipt of the notice, we or our transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and we or our transfer agent, as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and to deliver the proceeds therefrom to such holder;

(e) upon any registered holder of Common Shares ceasing to be a registered holder of one or more Common Shares, such holder shall be entitled to receive from our transfer agent, and the transfer agent shall pay as soon as practicable to such holder, an amount in cash equal to the proportion of the value of one Common Share that is represented by the fraction less than one whole Common Share at that time held by our transfer agent for the account of such holder and, for the purpose of determining such value, each Common Share shall be deemed to have the value equal to the Average Market Price in respect of the last stock dividend paid by us prior to the date of such payment; and

(f) for the purposes of the foregoing: (i) the calculation of a fraction of a Common Share payable to a Shareholder by way of a stock dividend and the calculation of the Average Market Price shall be computed to six decimal places, and shall be rounded to the nearest sixth decimal place; and (ii) neither us nor our transfer agent shall have any obligation to register any Common Share in the name of a person, to deliver a certificate or other document representing Common Shares registered in the name of a shareholder or to make a cash payment for fractions of a Common Share, unless all applicable laws and regulations to which we and/or our transfer agent are, or as a result of such action may become, subject, shall have been complied with to their reasonable satisfaction.

Preferred Shares

The Preferred Shares are issuable in series and the designation of, and the rights or privileges, restrictions and conditions attached to any series of Preferred Shares are to be established by our Board of Directors prior to the issuance thereof. The Preferred Shares have a preference over the Common Shares and any of our classes of shares ranking junior to the Preferred Shares with respect to the payment of dividends and the distribution of our assets in the event of liquidation, dissolution or winding-up of us or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs. No series of Preferred Shares has been designated to date and there are no Preferred Shares outstanding.

DIVIDEND POLICY

Dividends and Dividend Policy

When declared, cash dividends are made on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Shareholders of record on the last day of each such calendar month or such other date as determined from time to time by us.

The following monthly cash dividends on our Common Shares were declared by us for the periods indicated:

	Dividends per Common Share ($)		
Month	**2017**	**2016**	**2015**
January	0.020	0.045	0.045
February	0.020	0.020	0.045
March	0.020	0.020	0.045
April		0.020	0.045
May		0.020	0.045
June		0.020	0.045
July		0.020	0.045
August		0.020	0.045
September		0.020	0.045
October		0.020	0.045
November		0.020	0.045
December		0.020	0.045
Total	0.060	0.265	0.540

We carefully monitor the impact of all issues affecting our business and, the necessity to adjust our monthly dividends and our capital programs as conditions evolve. Dividends will normally be pre-approved on a quarterly basis in the context of prevailing and anticipated commodity prices and reconfirmed when declared. During periods of volatile commodity prices, we may vary the dividend rate monthly. See *General Development of our Business – Recent Developments*.

Our long term objective is to set a dividend policy at prudent levels while also pursuing cost-effective per share growth in reserves, production and funds from operations in western Canada. This in turn, is expected to provide a stronger base of cash flow leading to consistent and sustainable dividends into the future. Our dividend policy is reviewed monthly and is based on a number of factors including current and future commodity prices, foreign exchange rates, and our commodity hedging program, current operations and available investment opportunities.

Our Credit Facilities contain restrictions on our ability to pay dividends in certain circumstances. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities.

Cash dividends are not guaranteed. Our historical cash dividends may not be reflective of future cash dividends, which will be subject to review by our Board of Directors taking into account our prevailing financial circumstances at the relevant time. Although we intend to make dividends of our available cash to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends applicable law and other factors beyond our control. See *Risk Factors – Dividends*.

Unless otherwise specified, all dividends paid or to be paid by us are designated as "eligible dividends" under the *Income Tax Act* (Canada).

MARKET FOR OUR SECURITIES

Our Common Shares are listed for trading on the Toronto Stock Exchange under the trading symbol "TOG". The following table sets forth the price range and trading volume of our Common Shares on the Toronto Stock Exchange for the periods indicated.

	Price Range ($)		
Period	**Low**	**High**	**Trading Volume**
2016			
January	3.71	5.63	40,450,129
February	4.58	6.40	37,013,389
March	6.10	7.82	27,982,935
April	7.24	9.23	38,711,879
May	7.59	8.71	22,562,061
June	7.56	9.12	20,647,001
July	6.82	8.35	14,882,913
August	6.70	8.68	20,424,224
September	7.30	8.34	20,048,920
October	7.58	8.70	14,073,001
November	7.07	8.45	17,852,039
December	7.77	8.91	12,062,039
2017			
January	6.94	8.73	20,625,570
February	6.88	7.71	16,243,745
March (to March 27)	6.04	7.52	20,124,639

During the twelve month period commencing on January 1, 2016 and ending on December 31, 2016, we granted an aggregate of 1,993,842 share awards under our share award incentive plan to our officers, directors, employees and certain consultants which may be settled in Common Shares.

DIRECTORS AND OFFICERS

The name, municipality of residence, principal occupation for the prior five years and position with us of each of our directors and officers as of the date hereof are as follows:

Name and Residence	Position	Principal Occupation During Previous Five Years
David Johnson (2) (3) Calgary, Alberta	Chairman and Director	Mr. Johnson is an independent businessman with over thirty-five years of diverse experience in the oil & gas industry. Mr. Johnson was the Chairman of Progress Energy Resources Corp. from July 2004 until its sale to PETRONAS in 2012.
John Brussa (3) Calgary, Alberta	Director	Mr. Brussa is Chairman, and has been a partner since 1987, at the law firm of Burnet, Duckworth & Palmer LLP.
Raymond Chan (1) (3) Calgary, Alberta	Director	Mr. Chan was appointed Chairman of Baytex Energy Corp. in June 2014 and has been a Director of Baytex since October 1998. Since joining Baytex Mr. Chan has held the following positions: Senior Vice President and Chief Financial Officer (October 1998 to August 2003); President and Chief Executive Officer (September 2003 to November 2007); Chief Executive Officer (December 2007 to December 2008); Interim Chief Executive Officer (May 2012 to September 2012) and Executive Chairman (January 2009 to May 2014).
M. Bruce Chernoff (1)(5) Calgary, Alberta	Director	Mr. Chernoff has been the President and a Director of Caribou Capital Corp. (a private investment management company) since June 1999 and is the Executive Chairman and Chief Executive Officer and a Director of PetroShale Inc. Mr. Chernoff was the Chairman of Harvest Energy Trust from 2002 until its sale to the Korean National Oil Corporation in December 2009. Mr. Chernoff has been a Director of Maxim Power Corp. since January 2005 and serves as its Chairman of the Board.

Name and Residence	Position	Principal Occupation During Previous Five Years
Brett Herman (4) Calgary, Alberta	Director, President and Chief Executive Officer	Mr. Herman is our President & Chief Executive Officer and a Director. Mr. Herman was the President & Chief Executive Officer and a Director of Result Energy Inc. from November 2009 to April 2010 and the President & Chief Executive Officer and a Director of TriStar Oil & Gas Ltd. from August 2006 to October 2009.
R. Scott Lawrence (1) Toronto, Ontario	Director	Mr. Lawrence has been Managing Director, Head of Fundamental Equities at CPPIB since November 2016. Prior to this, Mr. Lawrence was Managing Director, Head of Relationship Investments and Senior Principal, Private Investments, and Infrastructure of CPPIB since September 2005. Prior thereto Mr. Lawrence was a Senior Associate for Onex Corporation and a finance professional at GE Plastics and GE Capital Real Estate.
Dale Shwed (2) Calgary, Alberta	Director	Mr. Shwed has been the President & Chief Executive Officer and a Director of Crew Energy Inc. since June 2003.
Jason Zabinsky (4) Calgary, Alberta	Vice President, Finance and Chief Financial Officer	Mr. Zabinsky is our Vice President, Finance and Chief Financial Officer. Mr. Zabinsky was the Vice President and Chief Financial Officer of Result Energy Inc. from November 2009 to April 2010 and the Vice President and Chief Financial Officer of TriStar Oil & Gas Ltd. from January 2006 to October 2009.
Sandy Brown Calgary, Alberta	Vice President, Geosciences	Mr. Brown is our Vice President, GeoSciences. Mr. Brown was the New Ventures Manager/Senior Geological Advisor at Apache Canada from November 2007 to November 2014 and the Vice President, Exploration of Rock Energy Inc. from January 2003 to October 2007.
Shane Manchester Calgary, Alberta	Vice President, Operations	Mr. Manchester is our Vice President, Operations. Mr. Manchester was the Vice President, Operations of Vero Energy Inc. from March 2006 to November 2013.
Jeremy Wallis Calgary, Alberta	Vice President, Land	Mr. Wallis is our Vice President, Land. Mr. Wallis was the Vice President, Land of Result Energy Inc. from November 2009 to April 2010 and the Vice President, Land of TriStar Oil & Gas Ltd. from January 2006 to October 2009.
Mike Wihak Calgary, Alberta	Vice President, Production	Mr. Wihak is our Vice President, Production. Mr. Wihak was the Vice President, Operations of Result Energy Inc. from November 2009 to April 2010 and the Vice President, Operations of TriStar Oil & Gas Ltd. from January 2008 to October 2009.
Marvin Tang Calgary, Alberta	Controller	Mr. Tang is our Controller since March 31, 2016. Mr. Tang was our Assistant Controller since April 2013. Mr. Tang was the Manager of Financial Reporting of Result Energy Inc. from November 2009 to April 2010 and the Manager of Financial Reporting of TriStar Oil & Gas Ltd. from May 2008 to October 2009.

Notes:

(1) Member of our Audit Committee.
(2) Member of our Reserves Committee.
(3) Member of our Corporate Governance & Compensation Committee.
(4) Member of our Disclosure Committee.

Each of our directors were appointed in 2012, other than Mr. Lawrence who was appointed in 2013, and will hold office until the next annual meeting of our Shareholders or until his successor is duly elected or appointed, unless his office is earlier vacated in accordance with our articles or by-laws.

Pursuant to an agreement we have with CPPIB, for so long as CPPIB owns greater than 10% of our outstanding Common Shares, it has the right to participate in future offerings of securities by us, whether by way of public offering or private placement. This includes any offering of Common Shares and securities convertible or exchangeable into Common Shares, up to its *pro rata* ownership interest immediately prior to such offering in the case of a public offering or a private placement to five or more investors, in order to maintain its *pro rata* percentage ownership interest in us, and up to all of the offering in the case of a private placement to less than five investors. CPPIB is also entitled to two Board nominees as long as it owns 20% or greater of our outstanding Common Shares. CPPIB currently holds approximately 25.35% of our outstanding Common Shares and has nominated R. Scott Lawrence as its nominee to our Board.

As a group, our directors and executive officers beneficially own, control or direct, directly or indirectly, 6.6 million Common Shares, representing approximately 3.6% of our outstanding Common Shares. In addition, Mr. Lawrence is the Managing Director, Head of Fundamental Equities of CPPIB, which holds 46,601,200 Common Shares representing approximately 25.35% of our outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

Except in connection with the other matters disclosed below, to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than thirty consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Other than as set out below, to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Messrs. Brussa and Chernoff were formerly directors of Calmena Energy Services Inc. ("**Calmena**") (a public oilfield service company). Mr. Brussa resigned as a director of Calmena on June 30, 2014 and Mr. Chernoff resigned effective January 15, 2015. On January 19, 2015, a senior lender of Calmena made an application to the Court of Queen's Bench of Alberta (the "**Court**") to appoint an interim receiver under the Bankruptcy and Insolvency Act (Canada) (the "**BIA**") and trading in the common shares of Calmena was suspended by the Toronto Stock Exchange. On January 20, 2015, the senior lender was granted a receivership order by the Court.

Mr. Brussa was a director of Enseco Energy Services Corp. ("**Enseco**") (a public oilfield service company), which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the BIA. Mr. Brussa resigned as a director of Enseco on October 14, 2015. On December 21, 2015 Enseco was assigned into bankruptcy by the receiver. Mr. Brussa was a director of Argent Energy Ltd. which was the administrator of Argent Energy Trust ("Argent Trust"), a public energy trust. On February 17, 2016, Argent Trust and its Canadian and United States holding companies (collectively "Argent") commenced proceedings under the Companies' Creditors Arrangement Act ("CCAA") for a stay of proceedings until March 19, 2016. On the same date, Argent filed voluntary petitions for relief under Chapter 15 of the United States Bankruptcy Code ("**Chapter 15**"). On March 9, 2016, the stay of proceedings under the CCAA was extended until May 17, 2016. Additionally on March 10, 2016 the U.S. Bankruptcy Court approved an order recognizing the CCAA as the foreign main proceedings under Chapter 15. On April 26, 2016, Argent made an application seeking approval for the sale of its oil and gas assets, the distribution of the net proceeds from the sale and an extension to the stay of proceedings, which was re-scheduled for May 4 and 5,

2016. On May 10, 2016, two orders were granted approving the sale of Argent's oil and gas assets and the distribution of net proceeds from the sale. On May 11, 2016, both orders were recognized by the U.S. Court within the Chapter 15 proceedings. On June 27, 2016, an order was granted which, among other things, extended the stay of proceedings under the CCAA until August 31, 2016. Mr. Brussa resigned on June 30, 2016. Mr. Brussa resigned as a director of Twin Butte Energy Ltd. ("**Twin Butte**"), a public oil and gas company, on September 1, 2016. On the same day, the senior lenders of Twin Butte (the "Senior Lenders") made an application to the Court of Queen's Bench of Alberta ("Court") to appoint a receiver and manager over the assets, undertakings and property of Twin Butte under the Bankruptcy and Insolvency Act (Canada) and trading in the common shares of Twin Butte was suspended by the Toronto Stock Exchange. On September 1, 2016, the Senior Lenders were granted a receivership order by the Court. Messrs. Brussa and Johnson were directors of Virginia Hills Oil Corp. ("**VHO**") (a public oil and gas company). On February 13, 2017, VHO received a demand notice and notice of intention to enforce security from its lenders and agreed to consent to the early enforcement of the lenders' security and the appointment of a receiver over all of the current and future assets, undertakings and properties of VHO. The receiver was appointed on February 13, 2017. Mr. Brussa and Mr. Johnson resigned as directors of VHO on February 24, 2017.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, 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.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See *Risk Factors*.

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such Board members will be provided to us.

The ABCA provides that in the event 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 under the ABCA. To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

AUDIT COMMITTEE

Composition of the Audit Committee, Charter and Review of Services

The members of our Audit Committee are Raymond Chan, M. Bruce Chernoff and R. Scott Lawrence. Raymond Chan is the Chair of the Audit Committee.

The Audit Committee operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this Annual Information Form as Schedule "A".

The Audit Committee charter requires all members of the Audit Committee to be financially literate and independent within the meaning of applicable securities laws. All current members of the Audit Committee meet these requirements.

The Audit Committee charter requires that any non-audit services by our auditors must be pre-approved by the Audit Committee.

Education and Experience of Members

The education and experience of each director relevant to the performance of his duties as a member of the Audit Committee are described below.

Raymond Chan (Chair)

Raymond Chan holds a Bachelor of Commerce degree from the University of Saskatchewan and is a Chartered Accountant. Mr. Chan currently serves as Chairman of Baytex Energy Corp. Mr. Chan has extensive financial and accounting experience obtained through senior executive positions in the Canadian oil and gas industry since 1982, including: Chief Financial Officer of Baytex Energy Ltd.; Tarragon Oil and Gas Limited; American Eagle Petroleum Ltd.; and Gane Energy Corporation.

M. Bruce Chernoff

M. Bruce Chernoff holds a Bachelor of Applied Science Degree in Chemical Engineering from Queen's University. Mr. Chernoff is a Professional Engineer with over 20 years of experience in the oil and gas industry. He has held various senior positions including Executive Vice President and Chief Financial Officer of Pacalta Resources Ltd. Mr. Chernoff is the President of Caribou Capital Corp., the Executive Chairman and Chief Executive Officer of PetroShale Inc. and is a director of several other public and private entities.

R. Scott Lawrence

Mr. R. Scott Lawrence holds an MBA from Harvard Business School and a Bachelor of Commerce (Honours) from Queen's University. Mr. Lawrence has been the Managing Director, Head of Fundamental Equities since November 2016. Prior to this, Mr. Lawrence was the Managing Director, Head of Relationship Investments and Senior Principal, Private Investment, and Infrastructure for CPPIB since September 2005. Prior thereto Mr. Lawrence was a Senior Associate for Onex Corporation from June 2001 to May 2004.

Auditor's Fees

KPMG LLP is our auditor. The following table sets out the aggregate fees billed by KPMG LLP to us in each of the last two fiscal years.

Year	Audit Fees (1)	Audit-Related Fees (2)	Tax Fees (3)	All Other Fees
2016	$368,000	$69,000	$Nil	$Nil
2015	$387,000	$60,000	$Nil	$Nil

Notes:

(1) Audit fees consist of fees for the audit of annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. The services provided in this category include quarterly review fees.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported as Audit Fees. The services provided in this category included research of accounting and audit-related issues, review of internal controls and language translation.

(3) Fees for tax compliance, tax advice and tax planning.

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, Saskatchewan, and Manitoba, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and we are 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 the areas in which we operate.

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, Intercontinental Exchange or the New York Mercantile Exchange 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 per 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 that 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. 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 m^3 (40 barrels of oil equivalent per day or 345,500 m^3 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.

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. In addition, a mineral rights tax is charged to owners of mineral rights paid on an annual basis at the rate of $1.50 per acre owned.

The amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into types, being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently:

- Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as third tier oil or fourth tier oil).

- Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002.

- For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the Production Tax Factor ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for old oil, 10.0 for new oil and third tier oil and 12.5 for fourth tier oil. The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for old oil, new oil and third tier oil, and 250 m^3 per month for fourth tier oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the 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 m^3 of gas for every m^3 of oil and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

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

As with conventional oil production, base prices based on a well reference rate of 250,000 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 certain 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 enhanced oil recovery ("**EOR**") projects during and subsequent to the payout of the EOR operations;

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

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

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

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to 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.

Manitoba

In Manitoba, the Crown owns approximately 20% of the oil and gas rights in the province, with the remainder being freehold lands. The royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated for each production month.

Producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the "**Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Holiday oil volumes must be produced within 10 years of the finished drilling date or the completion date of a major workover.

Wells drilled or receiving a marginal well major workover incentive after December 31, 2013 and prior to January 1, 2019 must pay a minimum royalty of 3% on Crown production or a minimum tax of 1% on freehold production. Wells receiving the *Pressure Maintenance Project Incentive* (outlined below) are not subject to the minimum royalty or minimum tax.

Wells drilled for injection, or converted to injection wells, in an approved enhanced recovery project, earn a one-year holiday for portions of the project area.

The Program consists of the following components, such components being subject to additional considerations under the *Crown Royalty and Incentives Regulation*:

- *Vertical Well Incentive* provides licensees of a vertical development or exploratory well drilled after December 31, 2013 and prior to January 1, 2019 with a holiday oil volume (a "**HOV**") of 500 m^3. To qualify, the well must be less than 1.6 kilometres from the nearest well cased for production from the same or deeper zone;

- *Exploration and Deep Well Incentive* provides a HOV for exploratory or deep oil development wells drilled after December 31, 2013 and prior to January 1, 2019 as follows:

    - Non-deep exploratory wells drilled more than 1.6 kilometres from the nearest well cased for production from the same or deeper zone earn a HOV of 4,000 m^3;

    - Deep exploratory wells drilled below the Birdbear formation earn a HOV of 8,000 m^3; and

  - Deep development wells completed for production in the Birdbear formation or deeper earn a HOV of 8,000 m^3;

- *Horizontal Well Incentive* provides a HOV of 8,000 m^3 for any horizontal well drilled after December 31, 2013 and prior to January 1, 2019 achieving an angle of at least 80 degrees for a minimum distance of 100 metres;

- *Marginal Well Major Workover Incentive* provides a HOV of 500 m^3 for any marginal well where a major workover is completed prior to January 1, 2019. A marginal oil well is a well or abandoned well that was not operated over the previous 12 months or that produced at an average rate of less than 3 m^3 per operating day;

- *Pressure Maintenance Project Incentive* provides a one-year exemption from the payment of Crown royalties or freehold production taxes for the unit tract in which an injection well is drilled or a well is converted to water injection. This exemption applies to the unit tract in which the vertical injection well is located and for a horizontal injection well to a maximum of four unit tracts within the drainage unit of the well. For a well that is converted to injection after December 31, 2013 and before January 21, 2019 and that has a remaining HOV, the exemption will be extended to 18 months; and

- *Solution Gas Conservation Incentive* provides a royalty and tax exemption on gas until December 31, 2018 for projects after December 31, 2013 that capture solution gas.

The Holiday Oil Volume Account, which allowed the movement of HOV to and from wells under specific conditions, was eliminated January 1, 2015. Previously, the holder of an existing account was able to make a one-time transfer of 2,000 m^3 to a well drilled between January 1, 2014 and December 31, 2014.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80% of the crude oil and natural gas rights in the southwestern portion of the province. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. 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, Saskatchewan, and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence.

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 environmental 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 liquid natural gas ("**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 Dear Region Plan and Upper Athabasca Region Plan have not been started.

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.

Manitoba

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

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 Act* ("**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 assets to deemed liabilities 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 assets to deemed liabilities under the AB LLR Program, increasing a licensee'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 licensees.

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 licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by 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 has 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.

Saskatchewan

In Saskatchewan, the Ministry of the Economy administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**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 licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees 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.

Manitoba

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

Climate Change Regulation

Federal

Climate change regulation 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 our 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 and are exempt from paying the carbon levy on fuels used in operations until this time. 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.

There are certain exemptions to the carbon levy imposed by the CLA. Until 2023, fuels consumed, flared or vented in a production process by conventional oil and gas producers will be exempt from the carbon levy. An exemption also applies for biofuels and fuels sold for export. In addition, marked fuels used in farming operations as well as personal and band uses by First Nations are exempt.

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.

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

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.

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.

Manitoba

The Government of Manitoba commenced public consultations with respect to the development of a cap and trade system to reduce GHG emissions in 2010. The enactment of *The Climate Change and Emissions Reductions Act* (Manitoba) set emission reduction targets as of December 31, 2012 at 6% below 1990 emissions and details the commitment of the Government of Manitoba to various initiatives in an effort to reduce GHG emissions. On December 3, 2015, the Government of Manitoba announced Manitoba's Climate Change and Green Energy Action Plan to address climate change and create green jobs. One component of this plan involves cutting GHG emissions by one-third of its 2005 levels by 2030, in part by implementing a cap and trade program for large emitters. Following this announcement, on December 7, 2015, the Government of Manitoba announced that it has signed a memorandum of understanding with both Ontario and Quebec formalizing the intent of all three provinces to link their respective cap-and-trade systems. However, legislation has not yet been enacted to implement the initiatives outlined in Manitoba's Climate Change and Green Energy Action Plan or the memorandum of understanding.

RISK FACTORS

An investment in our Common Shares is subject to various risks including those risks inherent to the industry in which we operate. If any of these risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in dividends on, and the market price of, the Common Shares. As a result, the trading price of our Common Shares could decline, and you could lose all or part of your investment. Cash dividends to Shareholders are not assured or guaranteed.

Before deciding whether to invest in any Common Shares, investors should consider carefully the risks set out below. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations.

The information set forth below contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled *Special Note Regarding Forward-Looking Statements*.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas we acquire, produce or discover. Our ability to market our oil and natural gas may depend upon our 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 our 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 us.

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 our control. These factors include economic and political conditions, in the United States, Canada, Europe China and emerging markets, the actions of the Organization of the Petroleum Exporting Countries ("**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 our 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 our 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 value of our reserves. We might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our 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 carrying value of our reserves, borrowing capacity, revenues, profitability and funds from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

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.

A prolonged period of low and/or volatile commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due, and could also result in a delay or cancellation of existing or future drilling, development or construction programs, a reduction or elimination of dividends on our Common Shares, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves. We conduct assessments of the carrying value of our assets in accordance with generally accepted accounting principles in Canada. If crude and natural gas forecast prices decline, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

Risks Associated with Forecast Prices

Our reserves as at December 31, 2016 are estimated using forecast pricing escalating prices as set forth under *Statement of Reserves Data – Forecast Prices and Costs*. These prices are substantially above current oil and natural gas prices. If oil and gas prices stay at current levels our reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that we 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 our inability to realize the full economic potential of our production or in a reduction of the price offered for our 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 our 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 our business and, in turn, our financial condition, operations and funds 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, 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 our production may, from time to time, be processed through facilities owned by third parties and over which we do 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 our ability to process our production and deliver the same for sale.

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. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able continue to find satisfactory properties to acquire or participate in. Moreover, management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that we 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 funds 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, we 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 for us.

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 our business, financial condition, results of operations and prospects.

As is standard industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain liability insurance in an amount we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, we 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 that 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 downward price pressure on oil and gas produced in Western Canada and additional uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of our reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our cash flow resulting in a reduced capital expenditure budget. Consequently, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis. Any decrease in value of our reserves may reduce the borrowing base under our Credit Facility, which, depending on the level of our indebtedness, could result in us having to repay a portion of our indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable and highly dilutive terms. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to us or at all.

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.

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 our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of the Common Shares.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our 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 and hydraulic fracturing, and waterfloods or our 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, we 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 we produce effectively.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect us from commodity price declines, we 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, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- 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 we may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate.

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 our 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 of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which our Common Shares will trade cannot be accurately predicted.

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 our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we 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 we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) could negatively affect our business, financial condition and the market value of the Common Shares or our assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

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 us and may delay exploration and development activities.

Substantial Capital Requirements

We anticipate 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, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our 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 our securities in particular.

Further, if our revenues or reserves decline, we 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 us. We may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. Our inability to access sufficient capital for its operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Credit Facility Arrangements

The Credit Facility and the amount authorized thereunder is dependent on the borrowing base determined by our lenders. The Credit Facility contains covenants that restrict, among other things, our ability to incur additional debt, enter into mergers and amalgamations, dispose of assets or pay dividends in certain circumstances. In addition, the Credit Facility contains certain financial ratio tests, which from time to time affect our debt servicing costs. In the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. Failure to comply with covenants could result in increased debt service costs or default under the Credit Facility, which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions.

There is no assurance that the maturity of the Credit Facility will be extended upon our request in the amounts requested or upon terms acceptable to us.

Our lenders use our reserves, commodity prices, applicable discount rate and other factors, to periodically determine our 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 our borrowing base, reducing the funds available to us under the Credit Facility. This could result in the requirement to repay a portion, or all, of our indebtedness.

If our lenders require repayment of all or portion of the amounts outstanding under the Credit Facility for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that we would be in a position to make such repayment. Even if we were able to obtain new financing in order to make any required repayment under the Credit Facility, it may not be on commercially reasonable terms or terms that are acceptable to us. If we are unable to repay amounts owing under the Credit Facility, the lenders under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Additional Funding Requirements

Cash flow from our reserves may not be sufficient to fund our ongoing activities at all times and from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and gas industry and/or global economic volatility, we 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, we 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 us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our 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 our 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 our capital expenditure plans may result in a delay in development or production on our properties.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future funds flows attributed to such reserves. The reserve and associated funds flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net funds 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. Our actual production, revenues, taxes and development and operating expenditures with respect to our 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, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net funds flows as summarized herein. Actual future net funds 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 funds flows derived from our 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 we intend to undertake in future years. The reserves and estimated funds 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 our reserves since that date.

Management of Growth

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

Dividends

The amount of future cash dividends we pay, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond our control, our dividend policy from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by us to finance capital expenditures using funds from operations.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Reliance on Key Personnel

Our 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 our business, financial condition, results of operations and prospects. We currently do not have any key personnel insurance in effect. The contributions of the existing management team to our immediate and near term operations 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 we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Operational Dependence

Other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside our 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 we have 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 we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we 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, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could materially adversely affect our financial and operational results

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 our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our 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 April 21, 2016. See *Industry Conditions – Royalties and Incentives*.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives 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 our cost 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 we are ultimately able to produce from our reserves.

Waterflood

We undertake or intend to 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 we need 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 we 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 we are 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 we are ultimately able to produce from its reservoirs. In addition, we may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on our results of operations.

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 us to incur costs to remedy such discharge. Although we believe that we 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 our business, financial condition, results of operations and prospects.

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes 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 our deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to our compliance requirements. In addition, the liability management system may prevent or interfere with our 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. The recent Alberta Court of Queen's Bench decision, Redwater Energy Corporation (Re) 2016 ABQB 278, found an operational conflict between the BIA 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.*

Issuance of Debt

From time to time, we 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 our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

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. Our actual interest in our properties may accordingly vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect our title to the oil and natural gas properties we control that could impair our activities on such properties and result in a reduction of the revenue we receive therefrom.

Expiration of Licences and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we 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 our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our business, financial condition, results of operations and prospects.

Income Taxes

We file all required income tax returns and believe that it is in full compliance with the provisions of the *Income Tax Act* (Canada) 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, 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 us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider 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 our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our business and operations. 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 we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, may realize less on disposition than their carrying value on our financial statements.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the exploration, development, production and marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our current properties, but also on the ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

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 our production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of our reserves as determined by independent evaluators.

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

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

Litigation

In the normal course of our operations, we 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 us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail 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 effect on our financial condition

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain 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, we 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 our available funds. The occurrence of a significant event for which we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our 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, we 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 our business that such a breach of confidentiality may cause.

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 our 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 our goods and services.

Third Party Credit Risk

We may be exposed to third party credit risk through its contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations, such failures may have a material adverse effect on our 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 our ongoing capital program, potentially delaying the program and the results of such program until we find 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 us being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Conflicts of Interest

Certain of our directors or officers 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 may require a director of 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 us 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 Officers – Conflicts of Interest*.

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 we do. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If we do implement such technologies, there is no assurance that we will do so successfully. One or more of the technologies we currently use or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be affected adversely and materially. If we are unable to use the most advanced commercially available technology or are unsuccessful in implementing certain technologies, our 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. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and funds flows.

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us 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 are 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 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 came 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 our business, financial condition, results of operations and prospects. Some of our 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 us and our operations and financial condition. See *Industry Conditions - Climate Change Regulation*.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of Common Shares which may be dilutive.

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 we acquire or discover. 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 our net production revenue.

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of Western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our 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 our business and financial results.

Information Technology Systems and Cyber-Security

We have 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. We depend 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, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our 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. We apply 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 our business, financial condition and results of operations.

Expansion into New Activities

The operations and expertise of our management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future we 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 our exposure to one or more existing risk factors, which may in turn result in our 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 our 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.

Additional information on the risks, assumption and uncertainties are found under the heading *Special Note Regarding Forward-Looking Statements.*

LEGAL PROCEEDINGS

There are no legal proceedings involving claims for damages for which the potential exposure is more than 10% of our current assets to which we are or was a party or in respect of which any of our properties are or were subject during the year ended December 31, 2016, nor are there any such proceedings known to us to be contemplated.

During the year ended December 31, 2016 there were (i) no penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against us that we believe would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by us with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed above or as may be disclosed elsewhere in this Annual Information Form, none of our directors, officers or principal shareholders, and no associate or affiliate of any of them, has or has had any material interest in any transaction or any proposed transaction which has materially affected or is reasonably expected to materially affect us or any of our affiliates.

AUDITOR, TRANSFER AGENT AND REGISTRAR

Our auditor is KMPG LLP, Chartered Professional Accountants. KPMG LLP has been our auditor since January 24, 2011.

Our 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, the only material contracts entered into by us within our most recently completed financial year, or before the most recently completed financial year but which is still material and is in effect, is our credit agreement in respect of our Credit Facility and our agreement with CPPIB, which are available on our SEDAR profile at *www.sedar.com*.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than Sproule, our independent engineering evaluator, and KPMG LLP, our independent auditor.

We used KPMG LLP for external audit services for the fiscal year ended December 31, 2016. KPMG LLP are our auditors and have confirmed that they are independent with respect to us within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

Reserve estimates by Sproule are included in this Annual Information Form. None of the designated professionals of Sproule have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associates or affiliates, except for John Brussa, one of our directors, is the Chairman and a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at *www.sedar.com* and on our website at *www.torcoil.com*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under equity compensation plans will be contained in our information circular and proxy statement for our annual meeting of shareholders to be held on May 9, 2017. Additional financial information is contained in our financial statements and the related management's discussion and analysis for the year ended December 31, 2016.

SCHEDULE "A"
AUDIT COMMITTEE CHARTER

TORC OIL & GAS LTD.

Role of the Audit Committee

The Audit Committee is a committee of the Board of Directors ("**Board**") of TORC Oil & Gas Ltd. (the "**Corporation**") to which the Board has delegated its fiduciary responsibility for oversight of the material financial risks of the Corporation. Financial risks include risk of: material misstatement in the financial statements or disclosures; and non-compliance with related regulations.

The Audit Committee ("**Committee**") carries out its responsibilities in cooperation with management, external auditors and external advisors on behalf of the Board. Following each meeting of the Committee, the Chairman of the Committee will make a report to the Board.

Composition of the Committee

The Chairman and members of the Committee are appointed by the Board and are required to be financially literate and independent of the Corporation.

The Audit Committee shall consist of at least three independent directors.

A director appointed by the Board to the Audit Committee shall be a member of the Audit Committee until replaced by the Board or until his or her resignation.

A director is independent if the director has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board, reasonably interfere with the exercise of the director's independent judgment. In determining whether a director is independent of management, the Board shall make reference to National Instrument 52-110 – *Audit Committees* or the then current legislation, rules, policies and instruments of applicable regulatory authorities.

In order to be financially literate, a director must be, at a minimum, able to read and understand financial statements that present a breadth and complexity of accounting issues generally comparable to the breadth and complexity of issues expected to be raised by the Corporation's financial statements.

Chairman

The Board shall appoint the chairman of the Committee (the "**Chairman**"). The role of the Chairman is to act as leader of the Committee to manage and co-ordinate the meetings and activities of the Committee and to oversee the execution by the Committee of its duties and responsibilities.

If the Chairman of the Committee is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting shall be chosen to preside by a majority of members of the Committee present at such meeting.

Authority of the Committee

The Committee shall have complete access to our personnel and the books and records of the Corporation. The Committee has the authority to engage external advisors if necessary to discharge its responsibilities and has the authority to fix compensation and authorize payment.

Audit Committee Meetings

The Committee carries out its duties through scheduled regular scheduled meetings or special meetings that may be requested by the Board, officers of the Corporation or the external auditor. The schedule, time and location of regular Audit Committee meetings is determined by the Chairman of the Committee and they generally coincide with the timing of the quarterly financial statements, management discussion and analysis, and financial press release.

Notice and Conduct of Meetings

Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee. The auditors shall be given notice of each meeting of the Audit Committee at which financial statements of the Corporation are to be considered and such other meetings as determined by the Chair and shall be entitled to attend each such meeting of the Audit Committee.

Notice of a meeting of the Audit Committee shall:

- be in writing;
- state the nature of the business to be transacted at the meeting in reasonable detail;
- to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and
- be given at least two business days prior to the time stipulated for the meeting or such shorter period as the members of the Audit Committee may permit.

A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee. However, it shall be the practice of the Audit Committee to require review, and, if necessary, approval of certain important matters by all members of the Audit Committee.

A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.

The Chairman of the Board, senior management of the Corporation and other parties may attend meetings of the Audit Committee; however the Audit Committee (i) shall meet with the external auditors independent of management as necessary, in the sole discretion of the Committee, but in any event, not less than quarterly; and (ii) may meet separately with management.

Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting.

Responsibilities of the Audit Committee

Committee Member Responsibilities

Knowledge of the business, financial and regulatory requirements

Committee members shall have and maintain a sufficient knowledge of company operations and changes in operations including the principal risks, systems and abilities of key personnel involved in financial reporting and disclosure processes to reasonably discharge their duties.

Independence

Audit Committee members have an obligation to remain independent of the affairs of the Corporation and shall disclose any circumstances that create a conflict of interest with role of a Committee member or may appear to create a conflict of interest.

Committee Responsibilities

The Audit Committee shall, in the exercise of its powers, authorities and discretion so authorized, conform to any regulations or restrictions that may from time to time be made or imposed upon it by the Board or the legislation, policies or regulations governing the Corporation and its business.

Management Oversight

It is the responsibility of the Audit Committee to satisfy itself on behalf of the Board that management has:

- identified the principal financial, regulatory and fraud risks; and,
- designed and implemented an adequate system of internal controls to mitigate the risks.

Review of the Corporation's Financial Statements & Disclosures

It is the responsibility of the Audit Committee to critically review the financial statements and disclosures of the Corporation and, if deemed appropriate, recommend the financial statements to the Board for approval. This process should also include but not be limited to review of:

- Changes in Accounting Policies
- Significant Management estimates
- Material or unusual transactions
- Material agreements

Review and Approve Significant Matters

It is the responsibility of the Audit Committee to review significant policies and matters that may materially impact financial statements and disclosures including but not limited to the following:

Accounting policies

The Audit Committee shall review the appropriateness of the accounting policies of the Corporation and approve significant policies.

Risk management

The Audit Committee shall review the risk management policies and procedures of the Corporation (i.e. hedging, litigation, insurance and marketing counterparty credit risk), including the annual review of insurance coverage and make appropriate recommendations to the Board with respect thereto.

Limits of authority

The Audit Committee shall periodically review the manner of delegation and limits of authority that management has implemented throughout the Corporation.

Litigation

The Audit Committee shall review the status of outstanding litigation at each regular Committee meeting.

Accounting Principle Changes

The Audit Committee shall schedule periodic updates on changes in accounting principles, regulations and emerging issues that may be relevant to the Corporation.

External Audit Responsibilities

It is the responsibility of the Audit Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Audit Committee.

Appointment of external auditors

The Audit Committee shall:

- recommend to the Board the appointment of the external auditors;
- review the performance of the external auditors and make recommendations to the Board regarding the replacement or termination of the external auditors when circumstances warrant;
- oversee the independence of the external auditors by, among other things, requiring the external auditors to deliver to the Audit Committee, on a periodic basis, a formal written statement delineating all relationships between the external auditors and the Corporation and its subsidiaries;
- 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 shall report directly to the Committee; and,
- 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.

Annual audit plan review

Audit Committee shall review the annual audit plan with the external auditors; monitor progress; and, upon completion of the audit, review their reports on the financial statements of the Corporation and its subsidiaries. The review should consider scope, approach, audit team experience and fees.

Non-audit services

The Audit Committee must pre-approve all non-audit services to be provided to the Corporation or its subsidiaries by external auditors. The Audit Committee may delegate, to one or more members, the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting and such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

Meet separately from management

The Audit Committee shall meet with the external auditors apart from management at each regular meeting to receive assessments relating to audit scope limitations, management cooperation and any issues relating to financial competencies.

Recommendations to Board

The Audit Committee is responsible for reviewing financial statements, disclosures and other significant policies and providing recommendations to the Board. Standing recommendations include:

- Appointment of external auditors
- Approval of financial statements, MD&A and other disclosure documents.
- Significant policies

Complaint System (Whistleblower Policy)

The Audit Committee shall establish and maintain procedures for:

- the receipt, retention and treatment of complaints received by the Corporation regarding ethical matters and business practices; and
- the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable ethical matters and business practices.

SCHEDULE "B"

FORM 51-101F2

REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of TORC Oil & Gas 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 management and Board of Directors:

			Net Present Value of Future Net Revenue Before Income Tax Expenses (10% Discount Rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date**	**Location of Reserves (Country)**	**Audited (M$)**	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule	December 31, 2016	Canada	Nil	1,558,830	Nil	1,558,830

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

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report entitled, "Evaluation of the P&NG Reserves of TORC Oil & Gas Ltd. (As of December 31, 2016)".

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta Canada
March 1, 2017

Original signed by Paul B. Jung, P.Eng.
Paul B. Jung, P.Eng.
Project Leader; Manager, Engineering

Original signed by Robert R. Warholm, P.Eng.
Robert R. Warholm, P. Eng.
Senior Manager, Quality & Assurance

Original signed by Rodney E. Fradette, P.Eng.
Rodney E. Fradette, P.Eng.
Senior Petroleum Engineer

Original signed by Gary R. Innis, P.Eng. on behalf of Reza M. Saedi
Reza M. Saedi, P.Eng.
Senior Petroleum Engineer

Original signed by Tanja Hale, P.Eng.
Tanja Hale, P.Eng.
Senior Petroleum Engineer

Original signed by Paul B. Jung, P.Eng. on behalf of Vladimir Iglesias, P.Eng.
Vladimir Iglesias, P. Eng.
Senior Petroleum Engineer

Original Signed by Weldon D. Dueck, P.Eng.
Weldon D. Dueck, P.Eng.
Senior Petroleum Engineer

Original signed by Ian K. Kirkland, P.Geol.
Ian K. Kirkland, P.Geol.
Senior Petroleum Geologist

Original signed by Alec Kovaltchouk, P.Geo.
Alec Kovaltchouk, P.Geo.
Vice President, Geoscience

Original signed by Cameron P. Six, P.Eng.
Cameron P. Six, P.Eng.
Chief Operating Officer

SCHEDULE "C"

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

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of TORC Oil & Gas Inc. ("**TORC**") is responsible for the preparation and disclosure of information with respect to TORC's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated and reviewed TORC's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "B" to the Annual Information Form of TORC for the year ended December 31, 2016 (the "**AIF**").

The reserves committee (the "**Reserves Committee**") of the board of directors of TORC (the "**Board of Directors**") has:

(a) reviewed TORC's procedures for providing information to the independent qualified reserves evaluator, Sproule Associates Limited ("**Sproule**");

(b) met with Sproule to determine whether any restrictions affected the ability of Sproule to report without reservation; and

(c) reviewed the reserves data with management and with Sproule.

The Reserves Committee has reviewed TORC'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, incorporated into the AIF, containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2, which is the report of Sproule 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 judgements regarding future events, actual results will vary and the variations may be material.

(signed) *"Brett Herman"*	(signed) "*Mike Wihak*"
Brett Herman President & Chief Executive Officer	Mike Wihak Vice-President, Production
(signed) *"Dale Shwed"*	(signed) "*David Johnson*"
Dale Shwed Director & Chairman of the Reserves Committee	David Johnson Director and Chairman of the Board

March 1, 2017