PRAIRIE PROVIDENT RESOURCES

ANNUAL INFORMATION FORM

For the year ended December 31, 2016

March 30, 2017

TABLE OF CONTENTS

NOTES TO READER

General

In this Annual Information Form (AIF), unless otherwise indicated or the context otherwise requires, the terms "we", "us", "our", and "the Company": (i) when used in reference to periods prior to September 12, 2016, refer to Lone Pine Resources Inc. and its subsidiary, Lone Pine Resources Canada Ltd. (now Prairie Provident Resources Canada Ltd.); and (ii) when used in reference to the period following September 12, 2016, refers to Prairie Provident Resources Inc., as parent corporation, together with its wholly-owned subsidiaries, Prairie Provident Resources Canada Ltd. (formerly Lone Pine Resources Canada Ltd.), Lone Pine Resources Inc. and (prior to its amalgamation with Prairie Provident Resources Canada Ltd. on January 1, 2017) Arsenal Energy Inc.

Unless otherwise indicated, information in this AIF is given as at the end of the Company's most recently completed financial year, being December 31, 2016.

Defined Terms

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms shall have the respective meanings set forth below:

"**ABCA**" means the *Business Corporations Act* (Alberta);

"**API**" means the American Petroleum Institute, and "**°API**" is an indication of the specific gravity of crude oil measured on the API gravity scale;

"**Arrangement**" means the arrangement under section 193 of the ABCA involving, among others, Prairie Provident, Lone Pine, Arsenal and the former shareholders of Lone Pine and Arsenal, as more particularly described under "*Company Overview and Background*" below;

"**Arsenal**" means Arsenal Energy Inc., an Alberta corporation acquired by Prairie Provident on September 12, 2016 pursuant to the Arrangement and later amalgamated with Prairie Provident Resources Canada Ltd. on January 1, 2017;

"**Board of Directors**" means the board of directors of the Prairie Provident;

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

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

"**gross**" means: (i) in relation to the Company's interest in production and reserves, its "company gross reserves", which are the Company's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interests of the Company; (ii) in relation to wells, the total number of wells in which the Company has an interest; and (iii) in relation to properties, the total area of properties in which the Company has an interest;

"**IFRS**" means International Financial Reporting Standards;

"**Lone Pine**" means, collectively and in reference to the period before the Arrangement, Lone Pine Resources Inc. and PPR Canada (then named Lone Pine Resources Canada Ltd.);

"**LPR Canada**" means Lone Pine Resources Canada Ltd., an Alberta corporation that was renamed Prairie Provident Resources Canada Ltd. following completion of the Arrangement and is an amalgamation predecessor of PPR Canada;

"**LPRI**" means Lone Pine Resources Inc., a Delaware corporation that is wholly-owned by Prairie Provident and holds a controlling equity interest in PPR Canada;

"**net**" means: (i) in relation to the Company's interest in production and reserves, the Company's working interest (operating and non-operating) share after deduction of royalties obligations, plus the Company's royalty interest in production or reserves; (ii) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and (iii) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company;

"**NGLs**" means natural gas liquids;

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

"**PPR Canada**" means Prairie Provident Resources Canada Ltd. (formerly Lone Pine Resources Canada Ltd.), an Alberta corporation that is a wholly-owned subsidiary of Prairie Provident and amalgamated with Arsenal on January 1, 2017;

"**Prairie Provident**" means Prairie Provident Resources Inc.; and

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

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

Non-IFRS Financial Measures

References are made in this AIF to terms commonly used in the oil and natural gas industry but which are not measures that have standardized meanings under IFRS and are not presented in the Company's financial statements, such as "funds from operations" and "EBITDAX". Accordingly, our use of such non-IFRS measures may not be comparable to similarly defined measures presented by other entities, as our calculation methods may differ from those applied by others.

Management uses such terms in the evaluation of the Company's operating and financial performance and to provide a measurement of the Company's efficiency and ability to generate the cash necessary to fund its capital expenditures, debt service obligations and other aspects of its business and affairs.

"***Adjusted funds from operations***" is calculated as cash flow from operating activities, as determined in accordance with IFRS, adjusted for changes in non-cash working capital, transaction costs, restructuring costs, decommissioning expenditures and other non-recurring items. Management believes that such a measure provides an insightful assessment of Prairie Provident’s operation performance on a continuing basis by eliminating certain non-cash charges and charges that are non-recurring or discretionary and utilizes the measure to assess its ability to finance operating activities, capital expenditures and debt repayments. Adjusted funds from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

"***Adjusted EBITDAX***" corresponds to defined terms in the Company's credit facility agreement and means net earnings before financing charges, foreign exchange gain (loss), exploration and evaluation expense, income taxes, depreciation, depletion, amortization, other non-cash items of expense and non-recurring items, adjusted for major acquisitions and material dispositions assuming that such transactions had occurred on the first day of the applicable calculation period. As transaction costs related to the Arrangement are non-recurring costs, Adjusted EBITDA has been calculated, excluding transaction costs, as a meaningful measure of continuing operating cash flows. For purposes of calculating covenants under the credit facility, Adjusted EDITDAX is determined using financial information from the most recent four consecutive fiscal quarters.

Barrel of Oil Equivalency Measures

This AIF includes various references to "barrels of oil equivalent" (boe).

We have adopted the industry-standard conversion ratio of six Mcf to one bbl when converting natural gas quantities to boes. Boes may be misleading, though, particularly if used in isolation. **A boe conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

Although the six-to-one conversion factor is an industry accepted norms, they are not reflective of price or market value differentials between product types. Based on current commodity prices, the value ratio between natural gas and oil is significantly different than the six-to-one ratio based on energy equivalency. On December 30, 2016, for example, the AECO spot gas price was $3.43 per Mcf and the Canadian Light Sweet crude oil price at Edmonton was $67.63 per bbl. If a price equivalent conversion ratio was applied based on these prices, the conversion factor would be approximately 1 bbl of oil for every 20 Mcf of natural gas. Accordingly, a conversion ratio based on six Mcf of natural gas to one bbl of oil may be misleading as an indication of value.

Currency References

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars and the term "$000s" means thousands of dollars.

Abbreviations

Following is a list of certain abbreviations used in this AIF.

Crude Oil and Natural Gas Liquids:		Natural Gas:	
bbl	barrel	Mcf	thousand cubic feet
bbl/d	barrels per day	MMcf	million cubic feet
Mbbl	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbl	million barrels	Btu	British thermal unit
NGLs	natural gas liquids	MMbtu	million British thermal units
		m^3	cubic metres

Barrels of Oil Equivalent:	
boe	barrels of oil equivalent of natural gas on the basis of 1 boe for 6 Mcf of natural gas
Mboe	one thousand barrels of oil equivalent
MMboe	one million barrels of oil equivalent
boe/d	barrels of oil equivalent per day

Conversion Ratios

In this AIF, certain measurements may be given in Standard Imperial Units or in International System of Units (or metric units). The following table sets forth certain standard conversions between the two measurement systems.

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

RESERVES DATA DISCLOSURE

The reserves attributed herein to the Company's current and former properties are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than those estimated, and the difference may be material.

Similarly, the future net revenues relating to reserves as presented in this AIF are also estimates only, and it should not be assumed that they represent the fair market value of such reserves. There is no assurance that the forecast prices and cost assumptions applied by the independent qualified reserves evaluator in evaluating the reserves will be attained, and variances between actual and forecast prices and costs could be material.

In addition, estimates of reserves and related future net revenues 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.

The determination of oil and gas reserves involves estimating subsurface accumulations of oil, natural gas and NGLs that cannot be measured in an exact manner. The preparation of estimates is subject to an inherent degree of associated risk and uncertainty, including factors that are beyond our control. The estimation and classification of reserves is a complex process involving the application of professional judgment combined with geological and engineering knowledge to assess whether specific classification criteria have been satisfied. It requires significant judgments based on available geological, geophysical, engineering, and economic data as well as forecasts of commodity prices and anticipated costs. As circumstances change and additional data becomes available, whether through the results of drilling, testing and production or from economic factors such as changes in product prices or development and production costs, reserves estimates also change. Revisions may be positive or negative.

In accordance with the requirements of NI 51-101, disclosure of reserves contained in this AIF uses the applicable terminology and reserves categories set out in the COGE Handbook.

All estimates of future net revenue are after the deduction of royalties, development costs, production costs and well abandonment and reclamation costs but before consideration of indirect costs such as general and administrative, overhead, interest and other miscellaneous expenses.

Estimates of reserves and future net revenue have been made assuming that development of each property in respect of which the estimate is made will occur, without regard to the likely availability of funding required for that development.

Reserves Categories

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

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

- "***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.

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

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

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

    - "***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 (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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

Levels of Certainty for Reported Reserves

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

- 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.

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

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

FORWARD-LOOKING STATEMENTS

This AIF contains forward-looking statements and forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking statements are typically (but not necessarily) identified by words such as "anticipate", "believe", "plan", "budget", "continue", "potential", "project", "estimate", "intend", "expect", "attempt", "target", "seek", "may", "will", "should", or similar words suggesting future outcomes. Although the Company believes that the forward-looking statements contained herein are reasonable based on currently available information, undue reliance should not be placed on them as they are subject to known and unknown risks and uncertainties, many of which are beyond the Company's control. Forward-looking statements are not guarantees of future outcomes.

In particular, this AIF and other documents filed by Prairie Provident with securities regulatory authorities in Canada contain forward-looking statements regarding, among other things:

- business plans and strategies;
- plans for and results of exploration and development activities;
- the source of funding for the Company's activities, including development costs;
- expectations regarding the Company's ability to raise capital and to add reserves and grow production through acquisitions, exploration and development;
- estimated quantities of natural gas, oil, and NGLs reserves within the Company's properties and recovery rates;
- estimated net present value of future net revenues from identified reserves;
- market prices for oil, natural gas and NGLs;
- capital expenditures;
- exploration, development, operating and transportation costs;
- oil, natural gas and NGL production estimates;
- sources of oil, natural gas and NGL production growth;
- supply and demand for oil, natural gas and NGLs;
- foreign currency exchange rates and interest rates;
- treatment under governmental regulatory regimes and tax, environmental and other laws;
- future operating and financial results;
- realization of the anticipated benefits of acquisitions and dispositions;
- performance characteristics of the Company's oil and gas properties;

- commodity prices and costs;
- planned construction and expansion of facilities;
- drilling and completion plans;
- secondary recovery projects;
- availability of rigs, equipment and other goods and services;
- procurement of drilling licenses and other necessary authorizations;
- reserves life measurements; and
- well abandonment costs and other abandonment and reclamation costs.

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

- general economic, market and business conditions in Canada, the United States and globally;
- variance of the Company's actual capital costs, operating costs and economic returns from those anticipated;
- risks inherent in oil and gas operations, including production risks associated with sour hydrocarbons;
- volatility in market prices for oil, natural gas and NGLs;
- differentials between benchmark commodity prices and those realizable by the Company;
- operational dependence on other industry participants;
- uncertainties associated with estimating oil, natural gas and NGL reserves;
- uncertainties associated with estimating production of oil, natural gas and NGLs from the Company's lands;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands, skilled personnel and services;
- unanticipated operating events that can reduce production or cause production to be shut in or delayed;
- incorrect assessments of the value of acquisitions or dispositions;
- geological, technical, engineering, drilling, completion and processing problems;
- increased operating costs and capital costs;
- changes in laws and governmental regulations;
- actions by governmental authorities, including increases in royalties or taxes;
- accessibility of capital when required and on acceptable terms;

- changes in interest rates or currency exchange rates;
- stock market volatility;
- ability to obtain required regulatory approvals and third party consents on a timely basis and on satisfactory terms; and
- those factors discussed under "Risk Factors" in this AIF.

The foregoing list of factors is not and should not be construed as exhaustive.

In addition, information and statements relating to "reserves" or other "resources" are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves or other resources described exist in the quantities predicted or estimated and, in the case of reserves, can profitably be produced in the future. See also "*Reserves Data Disclosure*".

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on assumptions, and are subject to known and unknown risks and uncertainties, both general and specific, many of which are beyond our control, that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations contained in the forward-looking statements or upon which they are based will in fact occur or be realized. Actual results will differ, and the difference may be material and adverse to the Company and its shareholders.

Forward-looking statements are based on the Company's current beliefs, as well as assumptions made by and information currently available to the Company concerning, such matters as: the accuracy of geological and geophysical data and interpretations of that data; future oil, natural gas and NGLs prices at which the Company's production may be sold; the ability of the Company to achieve drilling success consistent with management's expectations; the timing and cost of pipeline and facility construction and expansion and the ability of the Company to secure adequate product transportation; future capital requirements and expenditures; future exchange rates; the accessibility and cost of capital (including credit facilities); the ability to obtain financing on acceptable terms; future exploration, development, operating and transportation costs; the ability to economically produce oil and gas from its properties and the timing and cost to do so; the ability to add production and reserves through development and exploration activities; the ability to obtain qualified staff, equipment, services and supplies in a timely and cost-efficient manner; applicable regulatory requirements, including with respect to environmental protection; applicable royalty rates, and available means by which to bring the Company's production to market. Although management considers its beliefs and assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

The forward-looking statements contained in this AIF are made as of the date hereof and the Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by securities laws.

All forward-looking statements contained herein are expressly qualified by this cautionary statement.

COMPANY OVERVIEW AND BACKGROUND

General

Prairie Provident is a Calgary-based public company engaged in the exploration and development of oil and natural gas, with conventional operations primarily focused in the Western Canadian Sedimentary Basin in Alberta. We maintain a high working interest in a well-balanced portfolio of oil and gas properties, consisting of light and medium oil with associated natural gas. Our core areas are our Wheatland and Princess properties in Southern Alberta and our Evi property located in the Peace River Arch area of Northern Alberta.

Prior to September 12, 2016, our business was conducted by Lone Pine.

On September 12, 2016, pursuant to completion of the Arrangement: (i) the ownership and capital structure of Lone Pine was reorganized, with Prairie Provident becoming the parent corporation of Lone Pine and the former Lone Pine shareholders becoming shareholders of Prairie Provident; and (ii) Prairie Provident acquired all of the outstanding shares of Arsenal in exchange for Common Shares.

Prairie Provident was incorporated under the ABCA on July 29, 2016 for the purpose of participating in the Arrangement, and until September 12, 2016 did not carry on business other than in connection with the Arrangement.

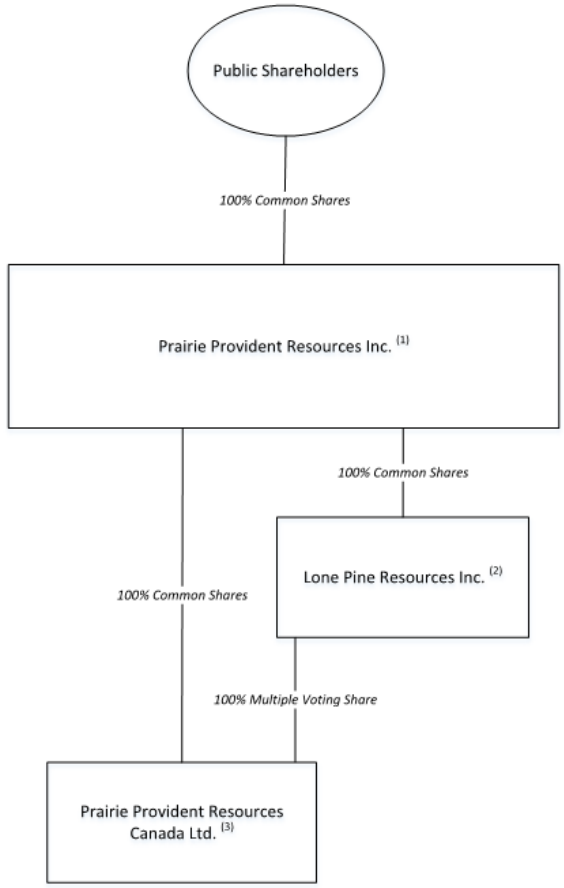
Our business today is conducted primarily through PPR Canada, which is a wholly-owned subsidiary of Prairie Provident, with our reserves, producing properties and principal exploration prospects located in the provinces of Alberta, British Columbia, Québec and the Northwest Territories.

Our head office is located at 1100, 640 - 5th Avenue S.W., Calgary, Alberta. Prairie Provident's registered office is located at 4500 Bankers Hall East, 855 - 2nd Street S.W., Calgary, Alberta.

The Common Shares are listed on the TSX under the symbol "PPR".

Intercorporate Relationships

Prairie Provident is the parent corporation of the corporate group consisting primarily of itself and PPR Canada and LPRI, which are its only material subsidiaries. The following diagram sets out the intercorporate ownership structure of Prairie Provident and its material subsidiaries.



Notes:

(1) Alberta corporation.

(2) Delaware corporation that holds a controlling equity interest in PPR Canada.

(3) Alberta corporation continuing from the amalgamation of PPR Canada and Arsenal on January 1, 2017.

General Development of our Business

On January 31, 2014, LPRI, LPR Canada and their affiliates at the time (collectively, the "**Lone Pine Group**") successfully completed a comprehensive capital reorganization and financial restructuring of the Lone Pine Group, pursuant to a plan of compromise and arrangement (the "**Restructuring Plan**") under the *Companies' Creditors Arrangement Act* (Canada) and ancillary proceedings under Chapter 15 of the United States Bankruptcy Code.

Implementation of the Restructuring Plan resulted in former unsecured creditors of the Lone Pine Group (comprised principally of former noteholders of LPR Canada) acquiring 100% of its outstanding equity and reduced outstanding debt by over $300 million. Secured creditors of the Lone Pine Group were fully repaid.

Following conclusion of the Creditor Protection Proceedings, we remained focused on exploration and development activities in the Western Canadian Sedimentary Basin.

In August 2014, the Company sold its gas-weighted undeveloped and developed properties in the Narraway and Ojay fields located in Alberta and British Columbia for cash proceeds of $110.4 million net of disposition costs. Proceeds from the disposition were used to fully repay borrowings under our then-outstanding credit facilities. The sale of our Narraway/Ojay properties significantly shifted our asset portfolio towards oil-focused opportunities.

In June 2015, PPR Canada entered into a lease acquisition agreement for mineral leases covering approximately 69,000 net acres of undeveloped lands in the Wheatland area in southeast Alberta. The mineral leases generally have a primary term of three years, with a three-year extension option. Future production from the acquired leases will be subject to a 15% to 17.5% flat-rate royalty. PPR Canada paid $9.3 million in cash consideration for the leases, and committed to annual capital expenditures of not less than (i) $10 million for the initial 12-month commitment period ending July 1, 2016, (ii) an additional $15 million for the second 12-month commitment period ending July 1, 2017, and (iii) an additional $20 million for the final 12-month commitment period ending July 1, 2018; provided that if the amount of capital expenditures incurred for any commitment period exceeds the minimum amount the excess will be applied to satisfy the capital commitment for the subsequent commitment period. During the third quarter of 2016, the lease acquisition agreement was amended whereby an additional approximate 4,500 net acres of undeveloped land in the Wheatland area were purchased for $0.6 million. The Company can meet its original capital commitment by incurring costs related to the additional undeveloped land purchased as well as on the lands purchased under the original agreement. In the event that Prairie Provident does not incur the minimum capital expenditures by the end of a given commitment period, the shortfall will be payable to the vendor. During the first two years of the leases, if the average WTI prices for a calendar quarter are below US$50/bbl, Prairie Provident may defer a portion of the drilling commitment from that commitment period to be allocated over the remaining term. Averaged WTI prices for the first two calendar quarters of the second commitment period ending July 1, 2017 were below US$50/bbl and, accordingly, the deferral option is exercisable by PPR Canada. On or before July 1, 2017, if PPR Canada fails to drill or elect to drill one well in a specific formation on certain lands, PPR Canada will be required to immediately surrender the leases pertaining to the specific formation. If PPR Canada makes the election but does not drill certain lands by July 1, 2018, $250,000 will be payable to the lessor. As of December 31, 2016, the capital commitment for the initial 12-month commitment period ending July 1, 2016 of $10.0 million was met and additional spending of $1.6 million has been applied towards the second 12-month commitment period ending July 1, 2017. In the first quarter of 2017, an additional $3.6 million has been incurred by drilling three wells in Wheatland, with $2.2 million expected to be spent towards these three wells in the second quarter of 2017. Prairie Provident expects to fulfill the remaining capital commitment under the lease acquisition agreement through its capital program at the Wheatland area. The deferral option noted above, if exercised, will provide PPR Canada with some flexibility around the timing of incurrence of such expenditures.

In December 2015, PPR Canada entered into a farm-in and option agreement to farm-in on certain additional lands in the Wheatland area. The lands in question are subject to a minimum gross capital commitment of $20 million in drilling and completion capital expenditures, of which PPR Canada's share is between 50% and 100% depending on the farmor's participation level. The gross capital commitment may be met by drilling a test well (an "Earning **Well**") in a targeted formation ("**Initial Earned Land**") or an additional well (an "**Option Well**") in the same geological formation in the offsetting half section ("**Offsetting Land**") of the Initial Earned Land. All Option Wells must be drilled prior to December 31, 2017. In exchange for drilling an Earning Well, PPR Canada will earn up to a maximum of 95% working interest in the Initial Earned Land, and may earn up to 100% working interest in the Offsetting Land. The farmor may participate up to a 50% working interest in each Earning Well and share capital expenditures accordingly. The farmor's participation in each Option Well will vary based on its working interest in the corresponding Earning Well. As at December 31, 2016, the $20 million gross capital commitment under the farm-in and option agreement had been fulfilled in entirety.

In June 2016, LPR Canada and Arsenal reached agreement on the terms of a strategic business combination, which was effected on September 12, 2016 pursuant to completion of the Arrangement. Upon completion, approximately 77% of the outstanding Common Shares (on a fully-diluted basis) were held by or issuable to former Lone Pine stakeholders, and approximately 23% were held by former Arsenal shareholders. LPR Canada was subsequently renamed Prairie Provident Resources Canada Ltd.

In connection with completion of the Arrangement, our senior secured credit facility was amended and restated to provide for a $55 million borrowing base. PPR Canada is the borrower under that facility, with Prairie Provident as guarantor.

On December 16, 2016, Prairie Provident completed a public offering for aggregate gross proceeds of approximately $4.95 million, comprised of 5,465,000 Common Shares issued on a flow-through basis under the *Income Tax Act* (Canada) with respect to "Canadian exploration expenses" at a price of $0.85 per share and 375,000 Common Shares issued on a flow-through basis with respect to "Canadian development expenses" at a price of $0.80 per share.

On January 1, 2017, PPR Canada and Arsenal amalgamated pursuant to the ABCA.

On February 13, 2017, Prairie Provident entered into an agreement with an arm's length vendor to acquire strategic light oil assets in the Greater Red Earth area of northern Alberta for cash consideration of $41.0 million, subject to customary adjustments (the "**Acquisition**"). The Acquisition was completed on March 22, 2017 and constitutes a "significant acquisition" for Prairie Provident for the purposes of Canadian securities law. We anticipate filing a business acquisition report in respect of the Acquisition on or before May 5, 2017, which will provide further information regarding the acquired properties. A copy of that business acquisition report (when filed) will be available under Prairie Provident's company profile on SEDAR at www.sedar.com.

On March 16, 2017, Prairie Provident completed a bought deal equity offering for aggregate gross proceeds of approximately $8 million, comprised of 5,195,000 Common Shares issued on a flow-through basis under the *Income Tax Act* (Canada) with respect to "Canadian exploration expenses" at a price of $0.77 per share and 5,971,000 subscription receipts at a price of $0.67 per subscription receipt. Each Warrant entitles the holder to acquire one Common Share at an exercise price of $0.87 per share until March 16, 2019.

In connection with completion of the Acquisition, our senior secured credit facility was amended and restated to provide for a $65 million borrowing base.

Business Plan and Strategy

Our strategy focuses on delivering accretive growth through development of conventional western Canadian oil and liquids plays that offer compelling economics and through opportunistic acquisitions. We are committed to maintaining strong financial position through capital discipline, operational efficiency and a robust hedging program.

Marketing and Delivery Commitments

Our natural gas production is generally sold on a month-to-month basis in the spot market, priced in reference to published indices. Our oil production is generally sold under short-term contracts at prices based upon refinery postings, and is typically sold at or near the wellhead. Our NGLs production is typically sold under term agreements at gas processing facilities at prices based on the average of posted prices less pipeline tariffs and fractionation fees. We believe that the loss of one or more of our current oil, natural gas or NGLs purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption.

Employees

As of December 31, 2016, we had 30 full-time employees and 45 contractors (on both full-time and part-time bases). In the ordinary course of our business we require the services of accountants, landmen, engineers, field operators and other professionals to aid in specialized areas and to explore and analyze hydrocarbon prospects and to determine a method in which prospects may be developed in a cost-effective manner. We also rely on the owners and operators of drilling and completion equipment to drill and develop our prospects to production. We have been able to acquire the services of these persons as needed in the past and believe that it will be able to continue to acquire these services as needed in the future.

Competition

The Company encounters competition in all aspects of its business, including acquisition of properties and oil and gas leases, marketing oil, natural gas and NGLs, obtaining services and labor and securing drilling rigs and other equipment necessary for maintaining, drilling and completing wells. Our ability to increase reserves in the future will depend on our ability to generate successful prospects on our existing properties, execute on organic development programs and acquire additional producing properties and/or prospects for future development and exploration. Many of the companies that we compete with have substantially larger workforces and greater financial and operational resources than the Company. Because of the nature of our oil and gas assets and management's experience in exploiting its reserves and acquiring properties, management believes that the Company effectively competes in its markets. See "*Risk Factors – Competitive Risk*" in this AIF.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial governmental authorities impose road bans that restrict the movement of drilling and service rigs and other heavy equipment, thereby limiting or temporarily halting drilling and producing activities and other oil and gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also adversely affect our ability to meet drilling objectives and capital commitments, and may increase competition for equipment, supplies and personnel during the winter months, which could lead to shortages and increased costs or delay or temporarily halt operations.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The Company's estimated reserves data at December 31, 2016, as set forth in the tables below, are based on the report dated January 20, 2017 prepared by Sproule Associates Limited ("**Sproule**") evaluating the crude oil, natural gas and NGLs reserves of the Company, as at December 31, 2016, using forecast prices and costs, in accordance with NI 51-101 and, pursuant thereto, the standards contained in the COGE Handbook (the "**Sproule Report**"), without any adjustment.

The estimates of the Company's proved reserves and probable reserves and related future net revenue set forth below (collectively, "**reserves data**") is based upon the Sproule Report, which evaluated the Company's crude oil, natural gas and NGLs reserves as at an effective date of December 31, 2016 using forecast prices and costs. The preparation date of the Sproule Report, being the most recent date to which information relating to the period ending December 31, 2016 was considered in its preparation, was January 20, 2017. Sproule evaluated proved and probable reserves attributable to the Company's interest in 100% of its properties and the net present value of estimated future cash flow from such reserves, based on forecast price and cost assumptions. Sproule did not evaluate possible reserves or resources.

The Sproule Report was prepared in accordance with NI 51-101 and, pursuant thereto, the standards set out in the COGE Handbook. We engaged Sproule to provide an evaluation of proved reserves and probable reserves only. No attempt was made to evaluate possible reserves or any resources other than proved reserves and probable reserves.

All of our reserves are located in Canada in the provinces of Alberta and British Columbia. We do not have unconventional reserves (bitumen, synthetic oil, coal bed methane, etc.).

A Report on Reserves Data by Independent Qualified Reserves Evaluator (Form 51-101F2) from Sproule and a Report of Management and Directors on Oil and Gas Disclosure (Form 51-101F3), each in the form required under NI 51-101, are attached as Schedules A and B, respectively, to this AIF.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions applied by Sproule in evaluating the Company's reserves will be attained, and variances could be material. The recovery and reserve estimates attributed to our properties are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and NGLs reserves may be greater than or less than the estimates provided herein, and the difference may be material.

See "*Reserves Data Disclosure*", "*Risk Factors*" and "*Forward-Looking Statements*".

The Company's estimated reserves data as at December 31, 2016 as set forth herein does not include any information regarding the additional reserves acquired by the Company pursuant to the Acquisition. Further information regarding the acquired properties will be included in the business acquisition report that Prairie Provident anticipates filing on or before May 5, 2017. A copy of that business acquisition report (when filed) will be available under Prairie Provident's company profile on SEDAR at www.sedar.com.

Reserves Data

Reserves Data (Forecast Prices and Costs)

The following tables set forth the Company's reserves data estimates as of December 31, 2016, as evaluated by Sproule using forecast prices and costs.

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2016

FORECAST PRICES AND COSTS

	Light and Medium Oil		Heavy Oil		Conventional Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED										
Developed Producing	4,463	3,953	77	76	14,040	11,710	304	237	7,184	6,218
Developed Non-Producing	328	283	–	–	4,407	3,671	49	38	1,111	933
Undeveloped	2,705	2,441	–	–	4,148	3,425	84	72	3,480	3,084
TOTAL PROVED	7,496	6,676	77	76	22,594	18,806	436	348	11,776	10,235
PROBABLE	2,798	2,392	228	214	8,740	7,127	164	135	4,646	3,929
TOTAL PROVED PLUS PROBABLE	10,294	9,068	305	291	31,335	25,933	600	483	16,421	14,163

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

FORECAST PRICES AND COSTS
(Before and After Income Taxes)

	Net Present Values of Future Net Revenue ($000s)										
	Before Income Taxes - Discounted at (%/year)					After Income Taxes - Discounted at (%/year)					Unit Value (1) Before Income Taxes - Discounted at 10%/year
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**$/boe**
PROVED											
Developed Producing	161,121	136,470	118,037	104,138	93,413	161,121	136,470	118,037	104,138	93,413	18.98
Developed Non-Producing	13,547	11,888	10,429	9,208	8,200	13,547	11,888	10,429	9,208	8,200	11.18
Undeveloped	67,146	44,863	30,150	20,149	13,107	67,146	44,863	30,150	20,149	13,107	9.78
TOTAL PROVED	241,814	193,222	158,616	133,495	114,720	241,814	193,222	158,616	133,495	114,720	15.50
PROBABLE	124,398	87,407	65,475	51,563	42,140	124,398	87,407	65,475	51,563	42,140	16.67
TOTAL PROVED PLUS PROBABLE	366,212	280,628	224,091	185,058	156,860	366,212	280,628	224,091	185,058	156,860	15.82

Note:

(1) Unit values are based on net reserves.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2016

FORECAST PRICES AND COSTS ($000s)

Reserves Category	Revenue (1)	Royalties (2)	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
TOTAL PROVED	681,706	71,110	279,002	65,230	24,549	241,814	–	241,814
TOTAL PROVED PLUS PROBABLE	976,557	109,531	393,675	79,099	28,040	366,212	–	366,212

Notes:

(1) Total Revenue includes company revenue before royalty and includes other income.

(2) Royalties include Crown, freehold, overriding royalties and freehold mineral tax.

FUTURE NET REVENUE BY PRODUCTION GROUP
as of December 31, 2016

FORECAST PRICES AND COSTS

		Future Net Revenue Before Income Taxes (3) (discounted at 10%/year)	
Reserves Category	**Production Type**	**$000s**	**$/boe**
TOTAL PROVED	Light and Medium Oil (1)	150,087	16.69
	Heavy Oil (1)	926	12.14
	Conventional Natural Gas (2)	7,604	6.52
	Total Proved	**158,616**	
TOTAL PROVED PLUS PROBABLE	Light and Medium Oil (1)	209,750	17.01
	Heavy Oil (1)	3,907	13.45
	Conventional Natural Gas (2)	10,434	6.75
	Total Proved Plus Probable	**224,091**	

Notes:

(1) Including solution gas (gas dissolved in crude oil) and other by-products.

(2) Including by-products but excluding solution gas.

(3) Unit values are based on net reserves for each production group.

Notes to Reserves Data Tables:

(1) Columns may not add due to rounding.

(2) All estimates of reserves data presented herein have been prepared in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook. Relevant definitions are set out in the following notes.

(3) Reserve estimates of natural gas include associated gas (the gas cap overlying a crude oil accumulation in a reservoir) and non-associated gas (an accumulation of natural gas in a reservoir where there is no crude oil).

(4) Unit values are based on net reserves volumes before income tax.

(5) Future Development Costs shown are associated with booked reserves in the Sproule Report and do not necessarily represent the Company's full exploration and development budget.

(6) "***Reserves***" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, with the use of established technology and under specified economic conditions which are generally accepted as being reasonable, and shall be disclosed. Reserves are classified according to the degree of uncertainty associated with the estimate.

(7) "***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.

(8) "***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.

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

(10) "***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.

(11) "***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.

(12) "***Undeveloped reserves***" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (*i.e.*, proved or probable) to which they are assigned.

(13) "***Forecast prices and costs***" are those: (i) generally acceptable as being a reasonable outlook of the future; and (ii) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in clause (i). The table under "Pricing Assumptions" below identifies benchmark reference prices that apply to the Company.

(14) "***Operating costs***" (or "***Production costs***") means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. Lifting costs become part of the cost of oil and gas produced. Examples of operating costs or production costs are: (i) costs of labour to operate the wells and related equipment and facilities; (ii) costs of repairs and maintenance; (iii) costs of materials, supplies and fuel consumed, and supplies utilized, in operating the wells and related equipment and facilities; (iv) costs of workovers; (v) property taxes and insurance costs applicable to properties and wells and related equipment and facilities; and (vi) taxes, other than income and capital taxes.

(15) "***Exploration costs***" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

(16) "***Development costs***" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from 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 the 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.

(17) "***Future income taxes***" are estimated: (i) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities; (ii) without deducting estimated future costs that are not deductible in computing taxable income; (iii) taking into account estimated tax credits and allowances; and (iv) applying to the future pre-tax net cash flows relating to the Company's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

(18) "***Exploratory well***" means a well that is not a development well, a service well or a stratigraphic test well.

(19) "***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.

(20) "***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.

(21) "***Stratigraphic test well***" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as: (i) "exploratory type" if not drilled into a proved property; or (ii) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

Pricing and Inflation Rate Assumptions

The reserves data estimates contained herein are based on forecast prices and costs, using Sproule's pricing, exchange rate and inflation rate assumptions as of December 31, 2016.

The forecast price and cost assumptions used in estimating the Company's reserves data assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The following table sets forth commodity benchmark reference pricing, inflation rates and exchange rates utilized by Sproule in the Sproule Report, which were provided by Sproule and was Sproule's then-current standard price forecast effective December 31, 2016. Price offsets and differentials for each property were determined by comparing actual historical benchmark prices to actual prices received at the property.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
USED IN PREPARING RESERVES DATA
(Forecast Prices and Costs)

Year	**Crude Oil**			**Natural Gas**	**NGLs**			**Inflation Rate**		
Year	**WTI Crude Oil** [(1)] ($US/bbl)	**Light Sweet Crude Oil** [(2)] ($Cdn/bbl)	**Western Canadian Select Crude Oil** [(3)] ($Cdn/bbl)	**Natural Gas AECO-C (NIT) Spot** ($Cdn/ MMBtu)	**Edmonton Propane** ($Cdn/bbl)	**Edmonton Butane** ($Cdn/bbl)	**Edmonton Condensate** ($Cdn/bbl)	**Inflation Rate – Operating Costs** (%/Year)	**Inflation Rate – Capital Costs** (%/Year)	**Exchange Rate** ($US/$Cdn)
Historical										
2012	94.19	86.57	73.08	2.43	47.40	64.48	100.76	1.0%	4.5%	1.001
2013	97.98	93.27	74.93	3.13	38.37	69.88	105.48	1.0%	0.7%	0.971
2014	93.00	93.99	81.06	4.50	44.42	68.02	102.39	2.0%	-1.0%	0.905
2015	48.80	57.45	44.83	2.70	6.17	36.81	61.45	1.8%	-23.2%	0.783
2016	43.32	52.80	38.30	2.18	13.60	34.32	55.71	1.6%	-3.3%	0.755
Forecast										
2017	55.00	65.58	53.12	3.44	22.74	47.60	67.95	0.0%	0.0%	0.78
2018	65.00	74.51	61.85	3.27	28.04	55.49	75.61	2.0%	2.0%	0.82
2019	70.00	78.24	64.94	3.22	30.64	57.65	78.82	2.0%	2.0%	0.85
2020	71.40	80.64	66.93	3.91	32.27	58.80	80.47	2.0%	2.0%	0.85
2021	72.83	82.25	68.27	4.00	33.95	59.98	82.15	2.0%	2.0%	0.85
2022	74.28	83.90	69.64	4.10	35.68	61.18	83.86	2.0%	2.0%	0.85
2023	75.77	85.58	71.03	4.19	37.46	62.40	85.61	2.0%	2.0%	0.85
2024	77.29	87.29	72.45	4.29	39.30	63.65	87.39	2.0%	2.0%	0.85
2025	78.83	89.03	73.90	4.40	41.19	64.92	89.21	2.0%	2.0%	0.85
2026	80.41	90.81	75.38	4.50	43.13	66.22	91.07	2.0%	2.0%	0.85
2027	82.02	92.63	76.88	4.61	45.14	67.54	92.96	2.0%	2.0%	0.85
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0%	2.0%	0.85

Notes:

(1) West Texas Intermediate (WTI) at Cushing, Oklahoma, 40º API, 0.5% sulphur.

(2) Canadian Light Sweet at Edmonton, Alberta, 40º API, 0.3% sulphur.

(3) Western Canadian Select at Hardisty, Alberta, 20.5 º API.

The weighted average historical prices realized by the Company for the year ended December 31, 2016 were $46.75 per bbl for crude oil, $2.21 per Mcf for natural gas and $17.91 per bbl for NGLs. For further information regarding the Company's production mix in 2016, see "*– Other Oil and Gas Information – Production History*" below.

Reserves Reconciliation

The following table sets forth a year-over-year reconciliation of the Company's estimated gross reserves as of December 31, 2016 to the prior year's estimates, based on forecast prices and costs, by principal product type.

	Light and Medium Oil			Heavy Oil			Conventional Natural Gas			Natural Gas Liquid			Total Oil Equivalent		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MBoe)	Gross Probable (MBoe)	Gross Proved Plus Probable (MBoe)
December 31, 2015 (1)	6,012	2,419	8,430	98	235	333	12,143	6,294	18,437	320	148	469	8,453	3,851	12,304
Extensions	87	79	166	–	–	–	1,173	2,080	3,253	22	33	55	304	459	763
Infill Drilling	36	9	45	–	–	–	673	177	850	11	3	13	159	42	200
Improved Recovery	81	72	153	–	–	–	27	20	47	4	3	7	90	78	167
Technical Revisions	(613)	(622)	(1,236)	35	3	39	(120)	(2,796)	(2,916)	(17)	(57)	(74)	(614)	(1,143)	(1,757)
Discoveries	333	76	409	–	–	–	8,193	1,949	10,142	138	33	170	1,836	433	2,269
Acquisitions	2,349	802	3,151	–	–	–	4,063	1,135	5,199	22	5	27	3,048	996	4,044
Dispositions	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Economic Factors	(98)	(36)	(134)	(18)	(10)	(28)	(280)	(117)	(397)	(8)	(4)	(12)	(171)	(70)	(241)
Production(3)	(690)	–	(690)	(38)	–	(38)	(3,278)	–	(3,278)	(55)	–	(55)	(1,329)	–	(1,329)
December 31, 2016 (2)	7,496	2,798	10,294	77	228	305	22,594	8,740	31,334	436	164	600	11,775	4,646	16,421

Notes:

(1) Opening balances based on an evaluation report prepared by Sproule dated April 12, 2016 and effective as of December 31, 2015.

(2) Columns may not add due to rounding.

(3) Production per above reserves reconciliation table does not include sulphur production, and therefore is slightly lower than the Company's reported production for 2016.

Year-over-year changes in the Company's estimated gross reserves from December 31, 2015 to December 31, 2016 are primarily the result of:

(i) new future development reserves bookings in the Wheatland area (extensions and infill drilling);

(ii) enhanced recovery from waterflood response in the Evi area (improved recovery);

(iii) revisions to undeveloped reserves in the Wheatland area, negative revisions to producing reserves in the Evi area, and positive revisions to producing reserves in the Wheatland area (technical revisions);

(iv) new drilling activities in the Wheatland area (discoveries);

(v) the Company's acquisition of Arsenal on September 12, 2016 (acquisitions); and

(vi) changes in the Sproule commodity price forecast (economic factors).

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are assigned by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Generally, proved undeveloped reserves are those reserves related to drilling wells or very near producing pools or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Generally probable undeveloped reserves are those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This category also includes probable reserves assigned to proved undeveloped locations.

The following tables set forth, for each product type identified, the volumes of proved undeveloped reserves and probable undeveloped reserves, respectively, attributed to the Company's properties in each of the financial years ended December 31, 2016, 2015 and 2014 and, in the aggregate, before that time, based on forecast prices and costs.

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBoe)	
Year	**First Attributed (1)**	**Total at Year End**	**First Attributed (1)**	**Total at Year End**	**First Attributed (1)**	**Total at Year End**	**First Attributed (1)**	**Total at Year End**	**First Attributed (1)**	**Total at Year End**
2014	–	2,332	–	–	–	167	–	16	–	2,376
2015	1,627	2,427	–	–	2,192	2,220	61	64	2,053	2,861
2016	579	2,705	–	–	2,687	4,148	33	84	1,059	3,480

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBoe)	
Year	**First Attributed (1)**	**Total at Year End**	**First Attributed (1)**	**Total at Year End**	**First Attributed (1)**	**Total at Year End**	**First Attributed (1)**	**Total at Year End**	**First Attributed (1)**	**Total at Year End**
2014	–	2,867	–	202	–	294	–	19	–	3,137
2015	240	1,420	–	204	3,341	3,574	78	82	875	2,302
2016	235	1,196	–	200	2,584	3,602	36	65	701	2,060

Note:

(1) "*First Attributed*" refers to previously unassigned volumes that were attributed to proved undeveloped reserves as at year-end of the corresponding fiscal year.

Once identified, undeveloped reserves are generally scheduled into the Company's development plans. We pace our development programs to optimize the value of undeveloped reserves. This pace is affected by changing economic conditions (due to pricing, and operating or capital costs), changing technical conditions (production performance or new data from wells, changing design parameters (such as using horizontal wells, rather than vertical wells, to develop a field), infrastructure constraints (pipeline or facility limitations), and surface access (landowners, weather, and/or regulatory approval). Over 95% of the Company's estimated proved plus probable undeveloped reserves are located in the Evi, Princess and Wheatland core areas. The Company has planned a program for the development of a portion of the undeveloped reserves in 2017, focusing on the Wheatland and Princess drilling and Evi waterflood programs.

Significant Factors or Uncertainties Affecting Reserves Data

Uncertainties are inherent in estimating quantities of reserves, including as a result of many factors that are beyond the Company's control. Subsurface accumulations of crude oil, natural gas and NGLs cannot be precisely measured. Reserves estimation is an inferential science that requires significant judgments based on available geological, geophysical, engineering and economic data as well as forecasts of commodity prices and anticipated costs. The accuracy of any reserves estimate is necessarily a function of available data and its interpretation. Estimates by different engineers can vary, sometimes significantly, and the quantities of crude oil, natural gas and NGLs actually and ultimately recovered will vary from reserves estimates.

As circumstances change and additional data becomes available – whether through the results of drilling, testing and production or other reservoir performance indicators, economic factors such as changes in commodity prices or development and production costs, changes in tax or regulatory regimes, or otherwise – reserves estimates also change. Revisions may be positive or negative.

Other than as discussed herein and the various risks and uncertainties to which participants in the oil and gas industry are exposed generally, the Company has not identified significant economic factors or uncertainties that it expects to affect any particular components of the reserves data disclosed herein. See "*Risk Factors*".

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs are estimated on an area-by-area basis using the Company's own internal historical costs when available and historical industry costs where necessary or appropriate. If representative comparisons are not readily available, an estimate is prepared based on regulatory requirements. The economic forecasts involved in the reserves estimates herein include abandonment, reclamation and salvage costs associated with existing and future wells with associated reserves. They do not include abandonment and reclamation costs associated with pipelines, facilities or wells that do not have associated reserves. Approximately $28.0 million (inflated and undiscounted) has been deducted in estimating the net present value of future net revenue of total proved and probable reserves as disclosed herein.

As at December 31, 2016, the Company had 1,173 gross (875 net) wells for which it expects to eventually incur abandonment costs, and 1,529 gross (1,219 net) wells for which it expects to eventually incur reclamation costs.

As at December 31, 2016, the Company's estimated future abandonment and reclamation obligations in respect of all of its properties (including those with no attributed reserves) was approximately $141 million (undiscounted). This was reflected in the Company's audited annual financial statements for the year ended December 31, 2016 as a decommissioning liabilities obligation of $97.7 million, as more particularly described in the notes thereto and related management's discussion and analysis.

Actual expenditures on abandonment and reclamation activities for the period ended December 31, 2016 totalled $4.5 million.

The following table sets forth the Company's estimated abandonment and reclamation costs, inflated at 1.7% per annum, for all owned wells and facilities as at December 31, 2016, on both an undiscounted basis and based on a 10% discount rate:

Abandonment and Reclamation Costs ($millions)	Undiscounted	Discounted at 10%
Total at December 31, 2016	141.1	38.7

Future Development Costs

The following table sets forth total future development costs deducted in Sproule's estimation of future net revenue (based on forecast prices and costs) attributable to the reserves categories noted below.

FUTURE DEVELOPMENT COSTS

	Forecast Prices and Costs ($000s) - Undiscounted	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2017	28,056	34,716
2018	22,350	27,291
2019	14,758	16,883
2020	–	–
2021	–	–
Thereafter	66	209
Total (undiscounted)	**65,230**	**79,099**
Total (discounted at 10%)	**58,701**	**71,134**

The Company currently expects that the capital required to fund estimated future development costs will be provided from its internally-generated cash flows, borrowings under its credit facility and, if necessary, issuance of equity or debt instruments. Costs of funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenues to some degree depending upon the funding sources utilized. The Company does not, however, anticipate that costs of funding would make the development of any property uneconomic. We may in the future consider alternative sources of financing in light of new or changing circumstances.

Estimates of reserves and future net revenues have been made assuming that each property in respect of which the estimate is made will be developed, without regard to the likely availability to the Company of funding required therefor. There can be no guarantee that such funds will be available or that the Company will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves could have a negative impact on future funds from operations.

Other Oil and Gas Information

Principal Properties

Following is a description of our principal oil and natural gas properties, all of which are located onshore in Canada with close proximity to processing and transportation infrastructure.

With respect to those properties to which reserves were attributed as of December 31, 2016 and were capable of producing but not then producing at such time, approximately 16% of such reserves were attributed to natural gas properties shut-in since May 2015 due to depressed gas prices, and approximately 25% and 39% related to wells drilled but not tied-in as of December 31, 2016 at Wheatland and Princess, respectively. As of the date of this AIF, two Wheatland wells have been tied-in. The Princess wells require future construction of gas pipelines to transport production to the nearest processing facilities.

Evi Area (Peace River Arch – Northern Alberta)

The Evi area is located in the Peace River Arch area of northern Alberta, which produced primarily light oil from the Devonian Slave Point, Gilwood and Granite Wash formations. As of December 31, 2016, we had an average working interest of approximately 82% in 36,160 gross (29,767 net) acres in and near the Evi field. This position offers a stable light oil production base with significant opportunity to increase our reserves base through waterflood development. The Company implemented its Evi waterflood pilot project in 2011, and currently has nine (nine net) injection wells (eight horizontal with one vertical) in operation through advancement of its waterflood project during 2015 and 2016. During the three months and year ended December 31, 2016, our Evi properties produced average sales volumes of approximately 1,458 boe per day (97% light oil) and 1,323 boe per day (95% light oil), respectively. The Company believes that it can ultimately enhance production rates and recoveries in the Evi area through further waterflood development, recompletions and infill drilling of its acreage.

Wheatland Area (Southeastern Alberta)

As of December 31, 2016, we leased approximately 78,143 gross (77,631 net) acres of freehold lands in and near the Wheatland area, located east of Calgary in Southeastern Alberta. This position offers an organic growth platform of medium grade oil and associated natural gas opportunities from the Mannville formations, primarily the Lithic Glauconite fluvial channels and the subaqueous marine Ellerslie deposition. During 2016, we drilled 14 gross (12.65 net) multi-stage fracture stimulated horizontal wells at Wheatland, of which 2 gross (2 net) wells remained to be tied in at December 31, 2016. During the three months and year ended December 31, 2016, our average sales volumes in the Wheatland area were approximately 1,797 boe per day (30% light/medium oil) and 1,264 boe per day (35% light/medium oil), respectively. The Company believes that it can significantly increase the area production with its large inventory of identified locations from this multi-zone stacked bypass pay oil play.

Princess Area (Southeastern Alberta)

Our Princess properties are located in Southern Alberta, approximately 55 miles northwest of Medicine Hat, where our ownership interest ranges between 50% and 100%. As at December 31, 2016, our Princess properties were comprised of 41,035 gross (39,515 net) acres. The zones of interest are the Second White Specks, Bow Island, Upper Mannville, Lower/Basal Mannville, Glauconitic, and Pekisko formations. During the three months and year ended December 31, 2016, our Princess properties produced average sales volumes of approximately 480 boe per day (83% medium oil) and 143 boe per day (approximately 83% medium oil), respectively.

Main Undeveloped Properties (Shales)

As of December 31, 2016, we held approximately 309,620 gross (241,884 net) acres in Québec that are prospective for the Utica Shale. Natural gas produced from this area is in close proximity to major markets in Canada and the northeastern United States, which historically has provided for premium product pricing compared to the NYMEX Henry Hub pricing. The Utica Shale is relatively shallow compared to other shale plays in North America, which the Company believes can provide for an economic advantage relative to the drilling costs associated with developing the resource. Development of these assets has, though, been suspended since 2011 due to changes in provincial energy policies and regulations.

As of December 31, 2016, we also had approximately 53,788 gross (52,995 net) acres in the Liard Basin located in the Northwest Territories, a natural gas shale play adjacent to the producing Horn River Basin, which are prospective for the Muskwa Shale. The Company believes that its Liard Basin acreage is analogous to the Muskwa Shale in the Horn River Basin. Our acreage is located in close proximity to a pipeline in the Northwest Territories, which would facilitate the sale and distribution of any natural gas that might be produced in the future. In 2011, we re-entered and recompleted a well in the Liard Basin, and in February 2012 applied to the National Energy Board of Canada for a commercial discovery declaration. That declaration was granted, and the Company's lease was continued to the year 2033.

No reserves are attributed to our Québec or Northwest Territories properties.

Oil and Gas Wells

The following table sets for the number and status of wells in which the Company owned a working interest as of December 31, 2016. A well bore with multiple completions is counted as only one well.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing (1)		Producing		Non-Producing (1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	400.0	326.0	418.0	336.0	75.0	28.9	184.0	146.0
British Columbia	–	–	–	–	25.0	12.1	37.0	13.6
Saskatchewan	3.0	0.7	16.0	4.8	–	–	1.0	0.4
Québec	–	–	–	–	–	–	11.0	4.4
Northwest Territories	–	–	–	–	–	–	3.0	2.2
Total	403.0	326.7	434.0	340.8	100.0	41.0	236.0	166.6

Note:

(1) Non-producing wells include wells capable of producing, but not producing, at December 31, 2016. Non-producing wells do not include wells that have been abandoned.

Properties With No Attributed Reserves

The following table summarizes undeveloped acreage in which the Company owned a working interest or held an exploration license as of December 31, 2016. Acreage related to royalty, overriding royalty and other similar interests, or related to options to acquire additional leasehold interests, is excluded from this summary.

	Undeveloped Acreage	
	Gross	Net
Alberta	245,252	207,544
Saskatchewan	281	99
British Columbia	14,502	10,578
Québec	304,500	237,788
Northwest Territories	53,788	52,995
West Cost (offshore)	112,310	112,310
East Coast (offshore)	19,084	343
Total	749,717	621,657

At December 31, 2016, 19,870 acres of our net undeveloped acreage will expire in 2017, if not extended by exploration or production activities.

Undeveloped acres are lands that have not been assigned reserves, and are mineral agreement specific. Except for the capital commitments disclosed in our annual financial statements for the financial year ended December 31, 2016, the Company does not have any other material work commitments related to its undeveloped acres in 2017. As of the date of this AIF, we are on track to meeting such 2017 work commitments.

Our land holdings range from discovery areas where tenure is held indefinitely by hydrocarbon test results or production to exploration areas in the early stages of evaluation. The Company regularly reviews the economic viability and ranking of its unproved properties on the basis of commodity pricing, capital availability and allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire and relinquished back to the mineral rights owner.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

Québec – Utica Shale Properties

In March 2011, the Government of Québec announced a strategic environmental assessment of the shale gas industry in the province.

In June 2011, the Province of Québec enacted legislation to exempt holders of exploration licenses from prescribed exploration work requirements and effectively extended the term of such licenses until June 2014, a deadline that was indefinitely extended in 2014 to a date to be determined by the government. The legislation prohibited oil and gas activities in the St. Lawrence River upstream of Anticosti Island and on the islands situated in that part of the river, and revoked without compensation oil and gas rights previously issued for that area. The revocation terminated exploration rights to 33,460 net acres of undeveloped lands under the St. Lawrence River held by the Company, representing approximately 14% of its overall net acres in Québec. In November 2012, the Company commenced proceedings under the North American Free Trade Agreement against the Government of Canada in response to Québec's expropriation of these rights, which are ongoing.

In 2013, the Québec government introduced a moratorium on shale gas development along the densely populated St. Lawrence valley for a period of up to five years, or until laws establishing new rules for hydrocarbon and exploration are adopted. Following completion in 2014 of the strategic environmental assessment on shale gas, the Government of Québec commissioned a further strategic environmental assessment of the broader oil and gas sector and committed to introducing new hydrocarbon legislation based on the new assessment. In April 2016, the Government of Québec released its Energy Policy 2030, which among other things expresses an intention to adopt a new approach for fossil fuels and plans to further clarify the legal framework governing such projects. In October 2016, the Québec legislature approved, in principle, Bill 106, An Act to implement the 2030 Energy Policy and amend various legislative provisions. These amendments include the new Petroleum Resources Act, which will govern the development of petroleum resources in Québec and replace existing provisions found in the Mining Act. The Bill was passed in December 2016; however, the related regulations and royalty regime have not yet been established. In light of the regulatory uncertainties, we continue deferring further field activity in respect of our Québec properties.

Northwest Territories – Liard Basin Properties

The remote location and geology of our Liard Basin properties result in drilling and capital costs that are much higher than those for other assets of the Company. In the current natural gas commodity price environment it is not economical to develop our Liard Basin properties. Liquefied natural gas ("**LNG**") projects proposed for the west coast of British Columbia may ultimately enhance the economic viability of developing the Liard Basin, but are themselves several years away from being developed. Furthermore, it is anticipated that many of these prospective LNG projects will secure supply from the Montney and Horn River gas fields that are being developed before the Liard Basin. Accordingly, development of the Liard Basin properties remains subject to significant economic hurdles. Our development activities in the Liard Basin have been limited to re-entering and recompleting an existing non-producing vertical test well in order to increase our understanding of the asset.

Forward Contracts

The Company is exposed to market risks from fluctuations in commodity prices, power prices, foreign exchange rates and interest rates in the normal course of operations, and maintains a risk management program to reduce the volatility of revenues, increase the certainty of funds from operations, and protect acquisition and development economics through hedging arrangements. Information regarding the Company's hedging arrangements in effect as of December 31, 2016 is set forth in the notes to our annual financial statements for the financial year then ended.

Tax Horizon

We were not required to pay any cash income taxes for the year ended December 31, 2016. Based on current estimates of future taxable income, levels of tax deductible expenditures and available tax pools, the Company anticipates that it will not face any cash income taxes before 2066.

Costs Incurred

The following table summarizes property acquisition costs, exploration costs, and development costs incurred by the Company for the year ended December 31, 2016.

Expenditures	**($000s)**
Property acquisition (disposition) costs (net) – proved properties	–
Property acquisition (disposition) costs (net) – unproved properties [(1)]	762
Exploration Costs [(2)]	126
Development Costs [(3)]	32,977
Non-oil and gas assets	1,010
Total	34,875

Notes:

(1) Includes cost of land acquired and lease rentals on unproved properties. See "*Properties with No Attributed Reserves*" above.

(2) Includes geological and geophysical costs and drilling and completion costs for exploratory wells.

(3) Includes drilling and completion costs for development wells and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The following table sets forth the number of exploratory wells and development wells completed during the year ended December 31, 2016 in which the Company had an interest, on both a gross and net basis.

	Development [(1)]		**Exploratory** [(2)]	
	Gross	**Net**	**Gross**	**Net**
Oil wells	14	12.65	–	–
Gas wells	–	–	–	–
Service wells	–	–	–	–
Stratigraphic test wells	–	–	–	–
Dry holes	–	–	–	–
Total	14	12.65	–	–

Notes:

(1) "*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.

(2) "*Exploratory well*" means a well that is not a development well, a service well or a stratigraphic test well.

Production Estimates

The following table sets forth the estimated 2017 production volumes reflected in Sproule's estimates of the Company's gross proved reserves, gross probable reserves and gross proved plus probable reserves, respectively, as disclosed in the tables set forth under "*Reserves Data*" above, together with information regarding the portion of those estimated first-year production volumes attributed to our Evi, Wheatland and Princess fields.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Total Oil Equivalent (boe/d)
TOTAL PROVED RESERVES					
Evi	1,845	–	320	44	1,943
Wheatland	491	–	9,636	166	2,263
Princess	643	–	845	1	785
Other Properties	267	44	2,959	31	835
Total Proved	3,246	44	13,760	242	5,826
TOTAL PROBABLE RESERVES					
Evi	324	–	42	6	336
Wheatland	178	–	2,425	41	623
Princess	36	–	43	–	43
Other Properties	6	2	348	2	68
Total Probable	544	2	2,857	48	1,070
TOTAL PROVED PLUS PROBABLE RESERVES					
Evi	2,169	–	362	50	2,279
Wheatland	669	–	12,061	207	2,886
Princess	679	–	888	1	828
Other Properties	273	46	3,306	34	904
Total Proved plus Probable	3,790	46	16,617	291	6,896

Our Evi, Wheatland and Princess fields are the only properties that account for 20% or more of the Company's estimated 2017 production as reflected in the Sproule Report.

Production History

The following table summarizes, on a quarterly basis for the year ended December 31, 2016, certain information in respect of our production volumes, product prices received, royalties paid, production (operating) costs incurred and resulting netback (before hedging).

	Quarter Ended			
	March 31, 2016	**June 30, 2016**	**Sept 30, 2016**	**Dec 31, 2016**
Average Daily Production [(1)]				
Light and Medium Oil (bbls/d)	1,762	1,672	1,618	2,578
Heavy Oil (bbls/d)	122	112	104	75
Conventional Natural Gas (Mcf/d)	7,698	9,733	7,269	12,300
NGLs (bbls/d)	124	134	104	142
Combined (boe/d)	3,291	3,540	3,038	4,845

	Quarter Ended			
	March 31, 2016	**June 30, 2016**	**Sept 30, 2016**	**Dec 31, 2016**
Average Price Received (2)				
Light and Medium Oil ($/bbl)	34.74	48.58	49.47	54.75
Heavy Oil ($/bbl)	17.47	32.89	33.53	38.40
Natural Gas ($/Mcf)	1.86	1.37	2.23	3.12
NGLs ($/bbl)	12.23	17.26	16.48	24.47
Combined ($/boe)	24.05	28.41	33.39	38.27
Royalties Paid				
Light and Medium Oil ($/bbl)	3.19	3.17	5.70	7.34
Heavy Oil ($/bbl)	0.99	1.70	2.40	2.67
Natural Gas ($/Mcf)	0.12	0.41	0.19	0.38
NGLs ($/bbl)	3.70	5.10	5.46	6.02
Combined ($/boe)	2.17	2.87	3.76	5.09
Production (Operating) Costs (3)(4)				
Light and Medium Oil ($/bbl)	25.14	19.56	25.26	18.60
Heavy Oil ($/bbl)	44.71	32.64	52.43	67.77
Natural Gas ($/Mcf)	2.47	1.82	2.06	1.09
NGLs ($/bbl)	15.40	8.88	12.22	6.99
Combined ($/boe)	21.47	15.60	20.60	13.92
Netback Received(5)				
Light and Medium Oil ($/bbl)	6.41	25.85	18.51	28.81
Heavy Oil ($/bbl)	(28.23)	(1.45)	(21.30)	(32.04)
Natural Gas ($/Mcf)	(0.73)	(0.86)	(0.02)	1.62
NGLs ($/bbl)	(6.87)	3.28	(1.20)	11.46
Combined ($/boe)	0.41	9.94	9.04	19.26

Notes:

(1) Before deduction of royalties.

(2) Not including any realized losses/gains on the Company's forward contracts on oil and natural gas.

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

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

(5) Netbacks are calculated by subtracting royalties and production (operating) costs from revenues. Realized losses/gains on the Company's forward contracts on oil and natural gas are not considered in the calculation of netbacks.

The following table indicates our average daily net production volumes (by product type) from the Company's important fields for the year ended December 31, 2016.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Total Oil Equivalent (boe/d)
Evi	1,224	–	395	34	1,323
Wheatland	371	–	4,924	72	1,264
Princess	119	–	145	–	143
Other Properties	195	103	3,789	20	950
Total	1,909	103	9,253	126	3,680

INDUSTRY CONDITIONS

The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and our oil and gas operations are subject to various Canadian federal, provincial, territorial and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure, and the exploration, development, production, handling, storage, transportation and disposal of oil and gas, oil and gas by-products and other substances and materials produced or used in connection with oil and gas operations. More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling and completion of wells, the method and ability to produce from wells, surface usage, transportation of production, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, loss or cancellation of governmental or regulatory approvals and the issuance of injunctions or similar orders that could delay, limit or prohibit certain of our operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil, natural gas and natural gas liquids that may be removed from the provinces and exported from Canada in certain circumstances. In order to conserve supplies of oil and natural gas, these agencies may also restrict the rates of flow of oil and natural gas wells below actual production capacity. Further, a significant spill from one of our facilities could have a material adverse effect on our results, operations, competitive position or financial condition.

We do not expect that any of these regulatory controls and restrictions will affect our operations in a manner significantly different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record. The Company is unable to predict what additional legislation, regulations or amendments may be enacted.

Transportation Capacity

Despite some recent oil pipeline capacity expansions, the overall capacity for Canadian oil to access tidewater and global markets is constrained. The transportation capacity deficit is not likely to be resolved quickly given that production of heavy oil and bitumen in Canada is expected to continue to increase. As further outlined below, several pipeline projects have been proposed and are in the approvals stage, and others have recently been completed. If the proposed projects are approved, the pipelines would help to alleviate the problems that Canada faces in accessing global markets for its oil supply.

While the use of rail transportation as an alternative to pipelines has significantly increased over the last few years, recent proposals for regulatory changes may also impact producers' ability to access markets by rail. The *Regulations Amending the Transportation of Dangerous Goods Regulations (TC 117 Tank Cars)* issued under the *Transportation of Dangerous Goods Act, 1992*, were adopted and came into force on May 20, 2015. The amended regulations will require rail tank cars to meet higher safety standards, which will be phased in over time until 2025.

Proposed Pipeline Projects

The proposed TransCanada Energy East pipeline would carry 1.1 million bbls/d of crude oil from Saskatchewan and Alberta to refineries in Eastern Canada and to a tidewater export terminal in Saint John, New Brunswick. In April 2016, the National Energy Board ("**NEB**"), the independent federal tribunal responsible for regulating pipelines and energy development and trade in Canada, released a preliminary timeline for the Energy East hearing process with an NEB report to the Governor-in-Council expected in March of 2018. Energy East panel sessions began in New Brunswick in August 2016, but were later suspended following protests at a panel session in Montreal. Following the suspension, the members of the panel recused themselves from further proceedings in an effort to preserve the integrity of the Energy East review process. In October 2016, the federal government appointed four temporary members to the NEB to carry out community and aboriginal engagement along the proposed pipeline route. In January, 2017, the NEB announced the appointment of three new panel members who will be responsible for continuing the review of the project.

Kinder Morgan Canada's proposed expansion of its existing Trans Mountain Pipeline from Edmonton, Alberta to Burnaby, British Columbia was approved by the NEB in May 2016. The project is expected to increase capacity by 590,000 bbls/d. Shortly after the NEB's approval of the pipeline expansion, the federal government announced an additional environmental review of the project by a three-member panel. On November 29, 2016, the Government of Canada granted approval for the Trans Mountain expansion project.

The TransCanada-led Keystone XL project would add 830,000 bbls/d in pipeline capacity for crude oil moving from Canada to the American Gulf Coast market. The project was previously rejected by former President Barack Obama on November 6, 2015, but may proceed following an executive order issued by President Trump on January 24, 2017. The executive order invited TransCanada to re-submit its application for a presidential permit to the U.S. Department of State, which the company did on January 26, 2017.

In 2014, the NEB approved the Enbridge Northern Gateway Pipeline with 209 conditions. The pipeline would have carried up to 525,000 bbls/d from Alberta to a new marine terminal in Kitimat, British Columbia for export; however in November 2016, the Government of Canada officially rejected the proposal.

Royalties

General

Each of the provinces and territories in which the Company operates has legislation and regulations governing royalties, land tenure, production rates and taxes, environmental protection and other matters under their respective jurisdictions. The royalty regime applicable in such jurisdictions is a significant factor in the profitability of our production. Crown royalties payable in respect of production from Crown, or public, lands are determined by government regulation and are typically calculated as a percentage of the value of gross production. The value of production and the rate of royalties payable depend on prescribed reference prices, well productivity, geographical location, field discovery date and the type of product produced.

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

Provincial governments will, from time to time, adopt incentive programs designed to encourage oil and gas exploration and development activity and improve earnings and cash flow within the industry. These programs may include royalty rate reductions, drilling credits, royalty holidays or royalty tax credits. Such programs are often of limited duration and target specified types of oil and gas activities.

Alberta

The majority of our current oil and gas production is from properties located in Alberta.

Modernized Framework

Royalties are important to the Alberta government's revenue stream. On January 1, 2017, the Government of Alberta implemented a modernized royalty framework (the "**Modernized Framework**") based on recommendations of the Royalty Review Advisory Panel. The Modernized Framework applies to all conventional wells spud on or after January 1, 2017, for a period of ten years. Wells spud prior to July 13, 2016 will continue to operate under the previous royalty framework (the "**Old Framework**"). Owners of wells spud between such dates may elect to opt-in to the Modernized Framework if certain criteria are met. After December 31, 2026, all wells will be subject to the Modernized Framework.

Under the Modernized Framework, royalties are determined on a "revenue-minus-costs" basis, with the cost component based on a drilling and completion cost allowance formula for each well, which is dependent on the vertical depth and horizontal length of the well. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis. The index attempts to incentivize innovation to reduce costs by allowing wells that operate under the average cost to remain at a lower rate of royalty even after recovering actual costs. Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative revenues from the well equals the drilling and completion cost allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate will be adjusted downward as the mature well's production declines, to a minimum of 5%. The drilling and completion cost allowance formula, post-payout royalty rates and production thresholds for mature wells came into effect on January 1, 2017.

As the Modernized Framework will use deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, efficient producers will benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they will continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

Strategic Royalty Programs

As part of the Modernized Framework, the Alberta government has announced two new strategic royalty programs to encourage oil and gas producers to boost production and explore new areas: the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs will take into account the higher costs associated with development of emerging resources and enhanced recovery methods when calculating royalty rates.

(1) Emerging Resources Program

The Emerging Resources Program began January 1, 2017, and is intended to encourage industry to pursue new oil and gas resources in higher-risk and higher-cost areas with large resource potential. To be eligible, the Minister of Energy must determine that the proposed project is in the public interest and the following criteria must be met:

- Large Resource Potential – The project must target a resource with large hydrocarbon potential that can generate substantial long-term returns for Albertans – wells must be expected to produce a minimum of 5,000 boe/day at peak production.

- Early Stage of Development – The project must develop a resource that is at an early and pre-commercial stage of development.

- Strong Potential of Commerciality – The project must be uncommercial and unlikely to become commercial without this program. In addition, a line of sight must be provided as to how the project could achieve commerciality within a reasonable timeframe with the program.

- Net Royalty Benefit to Albertans – The proposed project must provide incremental net royalty revenues with the assistance of the program in comparison to the royalty that would have been collected without the program.

Eligible wells pay a flat royalty rate of 5% until their combined revenue equals their drilling and completion cost. Unlike the Modernized Framework, the drilling and completion cost calculation includes a multiplier that ranges from 1.5 to 2.0, set at the time of project approval. The multiplier is based on the level of existing drilling activity at the time of application, and declines over time. After the benefit period ends, wells in the scheme will be subject to regular royalty rates under the Modernized Framework.

(2) Enhanced Hydrocarbon Recovery Program

This program began January 1, 2017 and replaces the Enhanced Oil Recovery Program under the Old Framework. Approved schemes target tertiary recovery methods involving the injection of materials into a reservoir to increase hydrocarbon production and recovery methods involving the injection of water or gas into a reservoir to increase hydrocarbon production. Eligible programs must receive technical approval from the AER and demonstrate increased hydrocarbon production from the pool over base recovery schemes for the pool, significantly greater costs than operating the base recovery scheme, and a net royalty benefit to the Crown over the life of the scheme as determined by a technical and economic review.

Eligible wells are subject to a flat 5% royalty on crude oil, natural gas and natural gas liquids produced from wells for a prescribed benefit period. After the benefit period ends, wells in the scheme will pay regular royalty rates under the Modernized Framework.

<u>Old Framework</u>

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional oil production under the Old Framework range from a base rate of 0% to a cap of 40%.

The Old Framework also included a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres, as well as the acid gas content of the produced gas. Subject to certain available incentives, effective from the January 2011 production month royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%.

Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

In terms of oil and natural gas production obtained from lands other than Crown lands, taxes are payable to the Province of Alberta. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the Crown. The tax levied in respect of freehold oil and gas production in the Province of Alberta is calculated annually based on a rate dependent on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

The Old Framework included a number of incentive programs, such as the Deep Oil Exploratory Well Program, the Enhanced Oil Recovery Royalty Program ("**EOR Program**"), the Natural Gas Deep Drilling Program, the Innovative Energy Technologies Program ("**IETP**") and the New Well Royalty Reduction program.

The Deep Oil Exploratory Well Regulation provided a limited royalty exemption for qualifying exploratory oil wells spudded or deepened between January 1, 2009 and December 31, 2013 that were deeper than 2,000 metres and had a producing interval below 2,000 metres. These wells qualified for a royalty exemption on either the first $1,000,000 of the royalty or the first 12 months of production. The Deep Oil Exploratory Well program expired on December 31, 2013 and no wells drilled after this date qualify for a reduction in royalty rates.

The EOR Program seeks to promote enhanced oil recovery methods that use the injection of fluids such as hydrocarbons, carbon dioxide, nitrogen or other approved chemicals. Operations that qualify for the program benefit from a reduced Crown royalty rate on oil production. The new Enhanced Hydrocarbon Recovery Program under the Modernized Framework replaced the EOR Program as of January 1, 2017.

The Natural Gas Deep Drilling Regulation, 2010 provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened after May 1, 2010, with producing intervals that are deeper than 2,000 metres. Exploratory wells will be subject to an escalating royalty credit in line with progressively deeper wells from $625/metre to $3,750/metre, with certain additional benefits available for the deepest wells. The royalty credit for development wells ranges from $625/metre to $3,000 per metre. All royalty adjustments under the program terminate within the earlier of five years from the finished drill date, or the date upon which the total royalty adjustment amount has been reduced to zero. The Modernized Framework extended the Natural Gas Deep Drilling program to allow all wells drilled throughout 2017 to qualify for the program, which will now continue until the end of 2022.

The IETP is intended to promote producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions to successful applicants. Alberta Energy determines which projects qualify for the IETP, as well as the level of support that will be provided. The IETP will expire on October 31, 2017.

The New Well Royalty Reduction ("**NWRR**") incentive program provides a maximum 5% royalty rate for the first 12 months of production of qualifying wells that commence or recommence producing conventional oil or natural gas on or after April 1, 2009. Production from a qualifying well is calculated at royalty of 5% until either the end of the eligible production month cap of the well, the date that the volume cap is reached for that well (or the date the well becomes part of a Project under the Oil Sands Royalty Regulation, 2009, whichever occurs first). The Modernized Framework extended the NWRR to the end of 2022.

As part of the NWRR, the government also enacted the Emerging Resources and Technology Initiative ("**ERTI**"), which is intended to accelerate new technologies and encourage the development of unconventional resources in the province by applying a maximum 5% royalty rate as set out below.

(1) Coalbed Methane New Well Royalty Rate – The purpose of the Coalbed Methane New Well Royalty Rate is to encourage new exploration, development and production from Alberta's gas resources within coal seams. Approved coalbed methane wells which (i) have a fluid code of "Coalbed Methane – Coals Only" when production commences, (ii) have no production prior to May 1, 2010, and (iii) have a Crown interest greater than zero when production commences, will receive a maximum royalty rate of 5% for 36 producing months or until production of 750 million cubic feet of gas.

(2) Shale Gas New Well Royalty Rate – The purpose of the Shale Gas New Well Royalty Rate is to encourage new exploration, development, and production from Alberta's shale gas resources. Approved shale gas wells which (i) have a fluid code of "Shale Gas Only" when production commences, (ii) have no production prior to May 1, 2010, and (iii) have a Crown interest greater than zero, will receive a maximum royalty rate of 5% for 36 producing months with no volume caps.

(3) Horizontal Gas New Well Royalty Rate – The purpose of the Horizontal Gas New Well Royalty Rate is to encourage the use of horizontal technologies and production from Alberta's gas resources. Approved horizontal gas wells which (i) are considered a horizontal gas well event as defined by the AER, (ii) have a spud date on or after May 1, 2010, and (iii) have a Crown interest greater than zero, will receive a maximum royalty of 5% for 18 producing months or until production of 500 million cubic feet of gas. This applies retroactively to wells where drilling commenced on or after May 1, 2010.

(4) Horizontal Oil New Well Royalty Rate – The purpose of the Horizontal Oil New Well Royalty Rate is to encourage deployment of new horizontal technologies in the development and production of Alberta's oil resources. Approved horizontal oil wells which (i) are oil or non-project oil sands well events defined as "horizontal" by the AER, (ii) have a spud date on or after May 1, 2010, and (iii) have a Crown interest greater than zero, will receive a maximum royalty rate of 5% and can apply retroactively to wells that commenced drilling on or after May 1, 2010.

British Columbia

After Alberta, the remainder of our current oil and gas production is from properties located in British Columbia.

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil can be up to 40% of the value of the oil produced and depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands can be up to 27% of the value of the natural gas and is determined by a sliding scale formula based on whether the gas is produced from Crown or freehold land, whether the gas is classified as conservation gas or non-conservation gas, the select price, and the reference price of the plant, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

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

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

(1) Deep Gas Well Credits – Credits are available for natural gas producers pursuing deep gas well projects through the deep well credit, the deep re-entry credit or the deep discovery well exemption. A well can only qualify for one of either the Deep Discovery Well, Deep Well or Deep Re-Entry incentives, and the producer is entitled to the incentive that is of the greatest benefit.

(a) Natural Gas Deep Well Credit – To earn a deep well credit, the well must be a gas well that is not part of a coalbed methane project. Deep gas wells are classified as either Tier 1 or Tier 2. Shallow gas wells with long horizontal segments with a spud date after April 1, 2014 will qualify as Tier 1, while all other wells that qualify for deep well credits will be Tier 2. Tier 1 deep well credits range from $445,000 to $2,800,000, and require the following: (i) the well is a horizontal well; (ii) the well has a spud date after April 1, 2014; (iii) the deepest productive well event has a true vertical depth to a completion point in the well of 1,900 metres or less; and (iv) the deepest productive well event has a deep well depth greater than 2,500 metres. Tier 2 deep well credits require the following: (i) for vertical wells, the well has a spud date on or after January 1, 2009, and the deepest productive well event has a true vertical depth to a completion point in the well greater than 2,500 metres; and (ii) for horizontal wells, the well has a spud date on or after September 1, 2009, the deepest productive well event has a true vertical depth to a completion point in the well greater than 1,900 metres, and the deepest productive well event has a deep well depth greater than 2,500 metres. Royalties are calculated based on deep well depth and the producer's share, which represents the producer's proportionate interest in the deepest well event in that well.

(b) Deep Re-Entry Credit – The deep re-entry credit was introduced to maximize the development of known resources by encouraging producers to re-enter previously drilled wells and drill deeper. Producers qualify for the credit if: (i) the well has a re-entry date after November 30, 2003; (ii) an application to alter the well has been submitted and approved before re-entry; (iii) if the spud date is before January 1, 2009, the total vertical distance to the top of the pay of the re-entry well event is greater than 2,300 metres; and (iv) if the well has a spud date after January 1, 2009, the total vertical distance to the completion point of the re-entry well event is greater than 2,300 metres. Royalties are calculated based on deep well depth and the producer's share.

(c) Deep Discovery Well Exemption – This program is intended to provide additional relief for extremely high risk drilling operations. Producers qualify for the credit if: (i) the well event discovers a new gas pool; (ii) the rig release date is after November 30, 2003; (ii) if the spud date is before January 1, 2009, the total vertical distance to the top of the pay is deeper than 4,000 metres; (iii) if the spud date is after January 1, 2009, the total vertical distance to completion point is deeper than 4,000 metres; and (iv) the surface location of the well is at least 20 kilometres away from the surface location of any well in a recognized pool of the same formation. Natural gas produced from a deep discovery well is exempt from payment of royalties for the first 36 producing months or 283,000,000 m^3 of raw gas, whichever comes first.

(2) Infrastructure Royalty Credit Program – The Infrastructure Royalty Credit Program is designed to increase oil and gas exploration and production in undeveloped areas and extend the drilling season to allow for year-round activity by providing royalty credits for up to 50% of the cost of building roads or pipelines. British Columbia has committed to a three year allocation of $360 million in royalty credits for 2016 to 2018 in order to construct and upgrade roads or construct pipelines. Special consideration will be given to application that provide access or enable or increase production in under-explored or under-developed areas of British Columbia. The selection criteria includes the benefit cost ratio, net present value and payback period to the Province, the leverage impact (in terms of opening up unexplored, under-explored or under-produced oil and gas areas) and the effect and degree the application has to accelerate the timing and amounts of new capital the proponent will invest in British Columbia.

(3) Clean Infrastructure Royalty Credit Program – In 2016, the Province of British Columbia initiated a new $20 million program to support the use of clean technologies to reduce greenhouse gas emissions in the oil and gas sector. The 2016 program will focus on retrofit, replacement or conversion projects to reduce greenhouse gas emissions from venting sources. Through this credit program, companies can apply for a credit to cover 50% of the cost of an eligible project. The evaluation criteria focuses on a Royalty Credit Emission Reduction Ratio, calculated by taking the clean infrastructure royalty credit request and dividing it by the GHG emissions reduction estimate, based on a five year period between January 1, 2017 and December 31, 2021.

(4) Coalbed Gas Royalty Program – This program is designed to initiate the development of the coalbed gas industry by providing royalty credits for coalbed gas wells. Base royalty rates are calculated in the same way as for conventional gas wells, but rates are reduced for wells with average daily natural gas production volumes less than 17,000 m^3 (0.6 MMcf). Producers are also eligible for a monthly Producer Cost Of Service allowance to help cover the costs of transporting the Province's share of raw gas to processing plants. The reduction is based on the actual cost of producing and transporting the gas, including water handling and disposal costs, and will be deducted from producers' gross royalties. Producers may also receive a credit of between $30,000 - $50,000 when a coalbed methane event is complete. The amount of the credit will depend on the producers' interest in the well event and the type of lease for the land in which the well event is located.

(5) Marginal Well Royalty Reduction – This program provides a royalty reduction for low productivity shallow gas wells that are not part of the coalbed gas royalty program. To qualify, the well must have an average daily production volume of less than 23 m^3 (0.81 Mcf) per metre (3.3 feet) of well depth. This program does not require the producer to apply. The Province will obtain product and depth information and automatically apply a lower royalty rate when the average daily rate of production in a calendar month is less than 25,000 m^3.

(6) Ultra-Marginal Royalty Program – This program provides an additional royalty reduction for low productivity shallow gas wells, and is more significant than the Marginal Well Reduction because it takes effect at higher rates of production; however, the conditions to qualify are more stringent. Qualification for wells spud between December 31, 2005 and April 1, 2014 require a true vertical depth of less than 2,500 metres for vertical wells, and less than 2,300 metres for horizontal wells. Horizontal gas wells spud after April 1, 2014 are not eligible for the reduction, and vertical wells must now have a completion point with a true vertical depth less than 2,500 metres. If the well is an exploratory "wildcat" well, the first 12-month period of production must yield an average daily production per metre of less than 17 m^3. For exploratory outpost or development wells, the first 12-month period of production must yield less than 11 m^3 of average daily production per metre.

(7) Net Profit Royalty Program – This program promotes the development and commercialization of technically complex and high risk oil and gas resources in British Columbia, and allows producers to pay lower royalty rates in early stages of the project in exchange for higher royalty rates once producers have recovered their capital costs. Established under the *Net Profit Royalty Regulation*, the program allows for royalty calculations based on the net profits of the project. A number of projects under this program were approved in the Horn River Basin in 2010; however, the Ministry of Natural Gas Development and Responsible Housing has confirmed that no further requests for applications have taken place since 2009.

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

Québec

Québec does not have a legislative and regulatory regime that is specific to the oil and gas industry and, accordingly, oil and gas exploration and development in Québec is subject to regulation under various laws and regulations. Currently, Québec's oil and gas resources are regulated principally under the province's mining laws and regulations pursuant to which, among other things, royalty rates of 5 to 12.5% of the market value in fees for petroleum and natural gas apply, depending on the depth of the wellhead. The previous attempt to amend the Mining Act, Bill 43, was defeated in the National Assembly on October 31, 2013. On December 10, 2013, Bill 70 – An Act to Amend the Mining Act, was given Royal Assent. The Act amends certain provisions of the Mining Act, including providing local municipalities with more decision-making powers; however, these amendments do not change any provisions relating to the royalty rates for oil and natural gas.

In April 2016, the Québec government unveiled its energy policy for 2016-2030 entitled "Energy Policy 2030, The Energy of Quebecers – a Source of Growth". This policy is the product of two major public consultations that took place in 2013 and 2015, and identifies five major targets to be met by 2030: (i) increase energy efficiency by 15%; (ii) reduce amount of petroleum product consumption by 40%; (iii) eliminate use of thermal coal-based energy; (iv) increase total renewable energy production by 25%; and (v) increase bioenergy production by 50%.

The Québec government aims to adopt a "new approach for fossil fuels" that will focus on safe transport of oil and petroleum products, responsible development of hydrocarbons in Québec, social acceptability of hydrocarbon projects in host communities and enforcement of the strictest environmental standards and techniques.

The Québec government is currently implementing a new statutory framework governing hydrocarbon exploration and exploitation in Québec, and has indicated that when a project is authorized, royalties will be demanded and used to fund energy transition and energy efficiency measures. A new agency responsible for energy saving and the energy transition will manage the royalties as The Energy Transition Fund.

In December 2016, the Québec National Assembly passed Bill 106, An Act to implement the 2030 Energy Policy and to amend various legislative provisions. Bill 106 contemplates the enactment of the new Petroleum Resources Act, which will govern the development of petroleum resources in Québec and replace existing provisions found in the Mining Act.

The government has not yet identified the new royalty regime for oil and gas that will be implemented under the new Petroleum Resources Act.

Northwest Territories

After the devolution of the authority of resource management from the federal government on April 1, 2014, public lands in the Northwest Territories ("**NWT**") are now managed under the Northwest Territories Lands Act and its related regulations. The Department of Industry, Tourism and Investment ("**ITI**") manages the onshore oil and gas.

Within the ITI, the Office of the Oil and Gas Regulator manages public health, safety and conservation regulatory responsibilities pursuant to the Oil and Gas Operations Act ("**OGOA**") for onshore oil and gas activities, outside of the Inuvialuit Settlement Region ("**ISR**"). Under federal legislation, the National Energy Board is the Regulator in offshore operations and is the Regulator under territorial legislation in the ISR.

With devolution, all relevant federal legislation became NWT legislation. Mirrored from the federal legislation, the content of the NWT legislation has not changed substantively. Royalties are now paid to the NWT government in most situations, with some exceptions. Through devolution, most federal land was transferred to the NWT government. The federal government has retained some "excluded" land such as the Norman Wells Proven Area. Royalties in respect of federal land are collected in accordance with the Devolution Agreement between the government of Canada, the government of NWT, the Inuvialuit Regional Corporation, the NWT Métis Nation, the Sahtu Secretariat, the Gwich'in Tribal Council and the Tlîchô government.

Royalties on production from Crown land in the NWT become payable once petroleum products from project lands become marketable. Royalties are not payable during the pre-production period when activities such as exploration, testing and drilling are being conducted.

Payout status is key in determining royalty rates. Prior to project payout, royalties of 1% of gross revenues are payable for the first 18 months of production, increasing 1% every 18 months to a maximum of 5%. After payout, the royalty will be the greater of 5% of gross revenues or 30% of net revenues.

Further to the OGOA, the government of the NWT published a draft of the Hydraulic Fracking Regulations on March 31, 2015. The proposed regulations set out new filing requirements in four areas: (1) baseline surface and groundwater information; (2) public disclosure of information; (3) measures to address air quality; and (4) enhanced reporting. The proposed regulation became available for online public comment for an initial period of 90 days, starting April 1, 2015. During this period, NWT residents were invited to provide comment on the draft through email, or through public engagement sessions that included stops in 11 communities across the NWT. The government later extended the consultation period until August 2015, and then announced that further consideration to the Hydraulic Fracking Regulations will be included in the broader NWT oil and gas strategy.

The development of the NWT government's oil and gas strategy will be broken up into three phases: (i) engagement reports, (ii) internal strategy, and (iii) plan implementation. The oil and gas strategy was initially expected to become available by July 2015, but a general territorial election held on November, 23, 2015 delayed the implementation of all phases of the oil and gas strategy. The government released the public engagement report, *Pathways to Petroleum Development*, in September 2015 and the government continues to work on the internal strategy. The internal strategy phase will involve the creation of goals and actions based on the engagement report and the plan implementation phase will require commitment from various NWT organizations to put resources and financial support behind the oil and gas strategy.

Land Tenure

The majority of oil and natural gas resources located in the provinces of Alberta, British Columbia, Québec and in the Northwest Territories are owned by the respective provincial and territorial governments. Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses and permits and regulations as issued by the applicable governments. Lease terms vary in length, usually from two to five years. Other terms and conditions to maintain a mineral lease are set out in the relevant legislation or are negotiated.

Lands in a petroleum and natural gas license are earned by the drilling of a well. A lease is proven productive at the end of its initial term by drilling, producing, mapping, being part of a unit agreement or by paying offset compensation. If a lease is proven productive, it will continue indefinitely beyond the initial term of the lease. The tenure only comes to an end when the holder can no longer prove his agreement is capable of producing oil or gas.

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

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

Environmental Regulation

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to international conventions and national, provincial, territorial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced or used in association with oil and gas operations, as well requirements with respect to oilfield waste handling, storage and disposal, land reclamation, habitat protection, and minimum setbacks of oil and gas activities from surface water bodies.

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

We have established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which we operate. We employ an environmental, health, and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance against the costs of clean-up operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

Alberta

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) and the *Oil and Gas Conservation Act* (Alberta).

The AER is the single regulator responsible for all energy development in Alberta. The mandate of the AER is to ensure the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment.

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

The Company may be affected by Alberta's frameworks for air quality, surface water quality and groundwater, under which parties may be required to participate in regional monitoring and report on the progress of implementation. The first of seven of these frameworks, the Lower Athabasca Region Plan ("**LARP**") under the *Alberta Land Stewardship Act* ("**ALSA**"), came into effect on September 1, 2012. LARP is a legislative instrument equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. There are four parts to the LARP's structure: the Introduction, the Strategic Plan, the Implementation Plan, and the Regulatory Details Plan. Currently the LARP is in the Implementation Plan stage, which includes regional actions, strategies and objectives that will support the achievement of the regional vision when carried out, as well as indicators to measure and evaluate the implementation's progress. Only the LARP's Regulatory Details Plan imposes binding legal obligations; however, the LARP does not create specific targets or regulate emissions of pollutants directly. Instead, it incorporates the pre-existing legislative framework that empowers the government and local authorities to establish and protect land conservation areas, encourage tourism, and regulate air, groundwater, and surface water quality. Current progress under the Implementation Stage is implemented by Alberta Environment and Parks, and current development focuses on a Biodiversity Management Framework, Landscape Management Plan, and the South Athabasca Oil Sands Regional Strategic Assessment and Sub-regional Plan.

The South Saskatchewan Regional Plan ("**SSRP**"), effective September 1, 2014, is the second of Alberta's regional plans and seeks to balance the government's economic, environmental, and social goals through an integrated system that considers the cumulative effects of all activities in a region. The SSRP provides for the establishment of seven land-use regions and the development of a corresponding regional plan for each region. Each plan identifies strategic directions for the region over the next ten years and can be updated every five years as required. Introduced under the auspices of the pre-existing land-use framework and the ALSA, SSRP approval was preceded by a consultation process involving aboriginal groups, stakeholders, municipalities and the public. The SSRP will be implemented through existing legislation governing the various forms of statutory consents.

Five additional regional plans under ALSA are in various stages of development: (i) Lower Peace Regional Plan; (ii) North Saskatchewan Regional Plan; (iii) Red Deer Regional Plan; (iii) Upper Athabasca Regional Plan; and (iv) Upper Peace Regional Plan.

The operations of the Company are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. It is impossible to predict the full impact of these laws and regulations on the

Company's operations. However, it is not anticipated that the Company's competitive position will be adversely affected by current or future environmental laws and regulations governing its current operations. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to environmental protection.

The AER has issued directives related to hydraulic fracturing operations in the areas of groundwater protection and induced seismicity. *Directive 083: Hydraulic Fracturing – Subsurface Integrity* mandates licensees demonstrate that operational risks have been considered in the selection and design of the wellbore construction, and to monitor and test to ensure that well integrity is maintained. It also subjects licensees operating in zones being drilled between 200 and 600 metres (depths above the base of groundwater protection in many areas) to conduct a risk assessment, observe prescribed setbacks for water wells and top of bedrock, and use environmentally friendly chemical additives or fluid compositions above the base of groundwater protection. *Directive 59: Well Drilling and Completion Data Filing Requirements* requires disclosure of hydraulic fracturing fluid composition, water source and volume data on a well-to-well basis.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future.

British Columbia

Environmental legislation in the Province of British Columbia is, for the most part, set out in the *Environmental Management Act* (British Columbia) ("**BCEMA**") and the *Oil and Gas Activities Act* (British Columbia) ("**OGAA**"), which regulate the storage, discharge and disposal of air contaminants, effluent and hazardous waste into the environment. The BCEMA provides for the imposition of significant penalties in the event of non-compliance and for the remediation of contaminated sites. New oil and gas projects, or modifications to existing projects, may be subject to a review under the *Environmental Assessment Act* (British Columbia).

The British Columbia Oil and Gas Commission (the "**BCOGC**") is the provincial, single-window regulatory agency with responsibilities for overseeing oil and gas operations in British Columbia, including exploration, development, pipeline transportation and reclamation. The BCOGC regulates all oil and gas activities under the OGAA, including shale and tight resources development activities.

The OGAA was enacted in 2010 to focus on effective oversight of oil and gas development while protecting public safety and the environment. Associated regulations under the Act include the *Drilling and Production Regulation*, *Pipeline Regulation*, *Environmental Protection and Management Regulation* and *Oil and Gas Waste Regulation*. These regulations also apply to conventional and unconventional development.

The Environmental Protection and Management Regulation establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the BCOGC to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act* (British Columbia), in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licenses, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licenses and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The government introduced mandatory public disclosure of hydraulic fracturing fluid ingredients in 2012 and established an online registry providing public access to information on fractured well locations and hydraulic fracturing fluid ingredients.

Québec

Environmental legislation in Québec is largely set out in the Environment Quality Act, which ensures the protection of the environment by way of a verification procedure that requires the issuance of a certificate of authorization for a wide range of commercial and industrial activities. The enabling legislation is widely construed so as to include anyone erecting or altering a structure, undertaking to operate an industry, carrying on an activity, using an industrial process, or increasing the production of any goods or services "if it seems likely" that this will result in an emission of contaminants, or change the quality of the environment, with some exceptions.

In 2011, Québec enacted legislation that revoked previously issued exploration licenses for the St. Lawrence River, upstream of Anticosti Island and the islands therein, and initiated a strategic environmental assessment of shale gas development in the province. In 2013, the Québec government introduced a moratorium on shale gas development along the densely populated St. Lawrence valley for a period of up to five years, or until laws establishing new rules for hydrocarbon and exploration are adopted.

The committee responsible for the strategic environmental assessment released their report in 2014. The report concluded that the risks associated with development are manageable. The findings were referred to the province's advisory office for environmental hearings, the Bureau d'audiences publiques sur l'environnement ("**BAPE**"). The BAPE subsequently conducted a series of public consultations and concluded that social acceptability, economic benefits and legislation were the main challenges associated with development in the near term.

The government has since commissioned an inter-ministerial committee to conduct a study on the entire oil and gas sector in the province with public consultation. In May 2016, the BAPE released the strategic environmental assessment of the entire hydrocarbon option, which among other things, recommended the government develop a strict legislative framework to develop resources responsibly to people and the environment. The particulars of any further prohibitions, restrictions or other requirements, including their duration, transitional provisions and exceptions, if any, that may arise from a strategic environmental assessment are not yet known.

Northwest Territories

Environmental legislation in the Northwest Territories is, for the most part, set out in federal legislation such as the Environmental Protection Act (Canada), the Northwest Territories Waters Act (Canada), the Canada Oil and Gas Operations Act (Canada), and associated regulations. These acts and regulations stipulate environmental conditions of operating approvals and the environmental standards to which monitoring and reporting obligations, in addition to emissions and waste discharge criteria, adhere to.

Environmental legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, or in the suspension or revocation of necessary licenses and approvals. The Company may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject the Company to statutory strict liability in the event of an accidental spill or discharge from a facility, meaning that fault on our part need not be established if such a spill or discharge is found to have occurred.

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 third parties and may require the Company to incur costs to remedy such a discharge in an event not covered by our insurance, which insurance is in line with industry practice. Furthermore, we expect incremental future costs associated with compliance with increasingly complex environmental protection requirements with respect to greenhouse gas ("**GHG**") emissions or otherwise, some of which may require the installation of emissions monitoring and measuring devices, the verification and reporting of emissions data and additional financial expenditures to comply with GHG emissions reduction requirements.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating ("**LLR**") program, which is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The Orphan Well Fund (the "**Orphan Well Fund**"), managed by the industry-funded Orphan Well Association ("**OWA**"), was established to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the LLR program if a licensee or working interest participant becomes defunct. The Orphan Well Fund is funded by licensees in the LLR program through a levy administered by the AER. The LLR program is designed to minimize the risk to the Orphan Well Fund posted by unfunded liabilities of licensees and prevent taxpayers in Alberta from incurring abandonment and reclamation costs. The LLR program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

On May 17, 2016, the Alberta Court of Queen's Bench issued a decision in the case of *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("***Redwater***") which may result in significantly higher costs for the public and industry related to abandonment and reclamation of uneconomic oil and gas assets. The Court in *Redwater* found that trustees and receivers of insolvent companies may disclaim to the AER uneconomic oil and gas assets, and then sell the valuable oil and gas assets for the benefit of secured creditors. The AER's historical approach to managing these liabilities has been to ensure that responsibility for both the uneconomic assets, i.e., those having a value less than the associated abandonment and similar liabilities, and the economic assets, is resolved prior to the transfer of any licenses associated with administered assets. The parties would achieve resolution of the liabilities through one of the following means: transferring those liabilities to a solvent licensee; posting security deposits; or by attending to the liabilities.

In situations where the assets were not purchased, financial liability would generally be limited to the current licensee and current working interest participants. Each party's liability was limited to its proportionate share of ownership in the assets (i.e., liability was not joint and several). To the extent that owners were insolvent or otherwise defunct, the AER could classify the assets as "orphaned". Orphaned assets became the responsibility of the OWA, and the receiver's liability would be limited to the value of the assets. Until *Redwater*, the licensee's obligations were thus imposed on trustees and receiver-managers by provincial legislation, including obligations with respect to the abandonment, reclamation and remediation of the administered assets.

Following the *Redwater* decision, receivers are now able to disclaim or renounce uneconomic assets to the AER. Once the assets are disclaimed, the receiver has no obligation to carry out the licensee's duties. Such duties will become the sole responsibility of the OWA if the AER deems the assets to be orphaned. This will result in higher costs being incurred by the OWA, which will be recovered through increased fees from industry participants. The Court of Queen's Bench decision has been appealed to the Alberta Court of Appeal.

On June 20, 2016, as part of its response to the *Redwater* decision, the AER released Bulletin 2016-16: Licensee Eligibility – Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("**Bulletin 2016-16**") that implements three important changes to the LLR program and the related regulatory regime, which are effective immediately and are likely to stay in effect until resolution of the *Redwater* litigation or implementation of further regulatory measures.

The first change is the AER will consider and process all applications for license eligibility under Directive 067: Applying for Approval to Hold EUB Licenses as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a license eligibility approval if appropriate in the circumstances. The second is for holders of existing but previously unused license eligibility approvals, prior to approval of any application (including license transfer applications), the AER may require evidence that there have been no material changes since approving the license 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 license eligibility was originally granted. The third is as a condition of transferring existing AER licenses, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management ratio of 2.0 or higher immediately following the transfer. Previously, the ratio threshold was 1.0. These changes may impact the Company's ability to transfer its licenses, approvals or permits, and which may further result in increased costs, delays and abandonment or restructuring of projects and transactions.

Based on the current economic environment, the number of orphaned wells in Alberta has increased significantly and accordingly, the aggregate value of the asset abandonment, reclamation and remediation liabilities assumed by the OWA has increased and may continue to increase. The OWA may seek compensation for such liabilities from industry participants, including the Company, through an increase in the annual levy, further changes to regulations or other means. While the impact on the Company of any legislative, regulatory or policy decisions as a result of the Redwater decision and its pending appeal cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact the Company and materially and adversely affect, among other things, the Company's business, financial condition, results of operations and cash flow.

The AER has also implemented the inactive well compliance program 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**"). This program 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 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 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 AER's inactive well compliance program is available on the AER's Digital Data Submission system.

British Columbia

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

Climate Change Regulation

Federal (Canada) – International Initiatives

Internationally, Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**"). All states that are parties to the UNFCCC are represented at the Conference of Parties. The main objective of the Conference of Parties is to adopt and review legal instruments and strategies to implement goals to stabilize greenhouse gas ("**GHG**") concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. In December 2015, UNFCCC members met in Paris, France. Members agreed to a new climate agreement (the "**Paris Agreement**") which Canada, along with over 160 other national governments, signed on April 22, 2016. The Paris Agreement is set to come into effect thirty days after at least 55 countries which together produce at least 55% of the world's GHGs ratify the Paris Agreement in their respective nations.

Canada ratified the Paris Agreement in October 2016. Under the Paris Agreement, Canada is legally bound to report and monitor its GHG emissions, though details of how this will take place have yet to be determined. Signatory countries agreed to meet every five years to review their individual progress on GHG emissions reductions and consider amendments to their targets. The Paris Agreement's main goal is to hold "the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C" overall, though individual country targets designed to meet these levels are not legally binding. Additionally, the Paris Agreement contemplates the parties will develop a new market-based mechanism related to carbon trading by 2020. It is expected that this mechanism will largely be based on the best practices and lessons learned from the

Kyoto protocol's clean development mechanism and joint implementation regimes. As described in more detail below, in October, 2016, the Canadian federal government announced a new national carbon pricing regime that will help Canada meet its goals under the Paris Agreement. U.S. President Donald Trump has indicated that he is seeking ways to withdraw the United States from the Paris Agreement.

On February 12, 2016 at the North American Energy Ministers' meeting, energy ministers from Canada, Mexico and the United States signed a memorandum of understanding on climate change and energy collaboration, and launched a website where information related to the North American energy industry will be aggregated and shared with the public. The memorandum of understanding provides that the signatories will collaborate and share information on six key areas: (i) experience and knowledge in the development of reliable, resilient and low-carbon electricity grids; (ii) modeling, deploying and accelerating innovation of clean energy technologies, including renewables; (iii) exchanging information in order to improve energy efficiency for equipment, appliances, industries and buildings, including energy management systems; (iv) exchanging information and promoting joint action to advance the deployment of carbon capture, use and storage; (v) identifying trilateral activities to further climate change adaptation and resilience; and (vi) sharing best practices and seeking methods to reduce emissions from the oil and gas sector, including methane and black carbon.

In March 2016, Canada and the United States announced a joint statement to take action on reducing methane emissions. The countries committed to reduce methane emissions by 40-45% below 2012 levels by 2025 from the oil and gas sector, and explore new opportunities for additional methane reductions.

On October 15, 2016, Canada and nearly 200 member countries of the United Nations agreed to reduce Hydrofluorocarbons ("**HFCs**") in Kigali, Rwanda. This agreement supports the Paris Agreement's goals to reduce GHGs internationally. Under this agreement, developed countries will start to phase down HFCs by 2019. Developing countries will follow with a freeze of HFCs consumption levels in 2024, with some countries freezing consumption in 2028. By the late 2040s, all countries are expected to consume no more than 15-20% of their respective baselines.

Canada is also part of a global initiative called the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants, supported by the United Nations Environment Programme. Their mandate is to address short-lived climate pollutants (e.g., black carbon, methane, tropospheric ozone, and hydrofluorocarbons), which exist in the atmosphere from between a few days to a few decades, in order to protect human health, the environment and to slow the rate of climate change within the first half of this century.

Federal (Canada) - Domestic Initiatives

Domestically, in December 2014, the Canadian government published Canada's Action on Climate Change, declaring its intention to take action on climate change by reducing GHG emissions through a sector-by-sector regulatory approach to protect the environment and support economic prosperity. To date, Canada has implemented GHG reducing regulations for renewable fuels, transportation, and coal-fired electricity.

Canada has sought to reduce short-lived climate pollutants through air emissions standards for new heavy-duty diesel vehicles and the national Air Quality Management System ("**AQMS**"). AQMS is a collaboration between the federal, provincial (excluding Québec), and territorial governments to improve Canadian air quality. Under AQMS, governments at every level collaborate with the Canadian Council of Ministers of the Environment in order to set and review the Canadian Ambient Air Quality Standards ("**CAAQS**"), which are numerical values of outdoor air concentrations of pollutants. CAAQS cover both fine particulate matter and ozone, with the current focus being on developing standards for nitrogen dioxide and sulphur dioxide. On May 25, 2013, the federal government incorporated CAAQS under sections 54 and 55 of the Canadian Environmental Protection Act, 1999 (Canada).

Under AQMS, each province and territory is committed to monitoring the air quality within its jurisdiction. Using the CAAQS as a baseline, each province and territory will then assess the level of management required to address current air quality levels. Provinces and territories will produce air zone reports, which include information regarding air management. Québec will not produce reports using CAAQS as a baseline, as the province believes the federal standards already exist under Québec's Clean Air Regulation. Once assessed, the provinces and territories provide air quality management levels for defined zones, ranging from 'Green' (maintain good air quality through proactive air management measures) to 'Red' (achieve air zone CAAQS through advanced air zone management actions).

It remains unclear what specific management tools the provinces and territories will utilize to bring air quality within CAAQS. The Government of Canada's current regulations are the Multi-sector Air Pollutants Regulations. Proposed amendments to the regulation would set base-level industrial emissions requirements for additional sectors. These regulations could affect the Company by requiring construction and operating permits and requiring air quality control expenditures in order to meet consistent standards across the country.

In February 2015, Environment Canada released a consultation document, titled Proposed Regulatory Measures on Hydrofluorocarbons, in order to promote discussion about HFC regulation and allow stakeholders from federal, provincial and territorial departments, as well as industry, environmental and public advocacy groups to comment on the proposed regulations. As of October 2016, none of the previously proposed approaches has been adopted to regulate HFCs domestically.

On March 21, 2015, the federal government proposed the Ozone-depleting Substances and Halocarbon Alternatives Regulations, which is intended to eventually replace the current Ozone-depleting Substances Regulation, 1998. The proposed regulation would introduce a system to monitor quantities of HFCs that are imported, manufactured and exported in Canada. This regulation would restrict the production or consumption of HFCs. This regulation is currently not in force with no indication from the government as to when it will be in force.

At the First Ministers Meeting in March 2016, the Prime Minister and all the provincial and territorial premiers agreed to the Vancouver Declaration on clean growth and climate change. To develop a pan-Canadian framework and implement the Declaration, four working groups were established: clean technology, innovation and jobs, carbon pricing mechanisms, specific mitigation opportunities, and adaptation and climate resilience. Each working group will assess impacts on economic and environmental outcomes and provide final reports to their appropriate Ministerial tables for review and implementation by early 2017.

On December 9, 2016, the federal government and all provinces except Saskatchewan signed a pan-Canadian framework (the "**Pan-Canadian Framework**") to meet the federal government's 2030 target of a 30-percent reduction in GHG emissions under the Paris Agreement. The Pan-Canadian Framework includes the following: all provinces and territories shall have carbon pricing in some form by 2018; provinces and territories can implement a carbon tax/carbon levy or a cap-and-trade system; each jurisdiction can choose to provide that all program revenues are to remain in the applicable jurisdiction; systems featuring a carbon tax/carbon levy shall have a $10/GHG tonne floor in 2018 rising by $10/GHG tonne per year to $50/GHG tonne by 2022; systems featuring a cap-and-trade program shall feature a declining cap to at least 2022 which mirrors the projected GHG emission reductions of carbon tax/carbon levy systems and shall result in aggregate GHG emission reduction outcomes by 2030 that line up with the federal plan; and each jurisdiction will provide regular, transparent and verifiable reports on the outcomes of their particular system. To date, there has been no legislation introduced on the federal carbon pricing scheme.

In comparison, Alberta's carbon levy (described in more detail below) was implemented at the beginning of 2017 with consumers paying $20/tonne, rising to $30/tonne by 2018. No announcement has been made by the Alberta government of price changes to the carbon levy past 2018. However, to comply with the federal carbon pricing scheme, the Alberta government will need to continuously increase the carbon levy to meet the $50/tonne federal target by 2022.

Alberta

In Alberta, GHG emissions are regulated under the Specified Gas Reporting Regulation ("**SGRR**") and the Specified Gas Emitters Regulation ("**SGER**") pursuant to the *Climate Change and Emissions Management Act* (Alberta). The SGRR requires facilities that emit 50,000 tonnes or more of GHGs per year to report their emissions to Alberta Environment and Parks ("**AEP**"). The SGER require Alberta facilities that emit more than 100,000 tonnes of GHGs per year to reduce emissions intensity by up to 20% below an average baseline taken from a facility's 2003 to 2005 emissions. Companies may meet these requirements through improvements to their operations; by purchasing Alberta-based emission reduction or offset credits; or by contributing to the provincial Climate Change and Emissions Management Fund. We do not operate any facilities that are regulated by the Alberta GHG emissions regulations.

In August 2015, the Alberta Government appointed a Climate Leadership Panel to provide advice to the government on the development of a comprehensive climate change strategy and to provide the AEP advice on a comprehensive set of policy measures to reduce GHG emissions in Alberta. In November 2015, the Government released the Panel's report and announced that it would implement the Climate Leadership Plan (the "**Plan**"), including the Panel's recommendations on phasing out coal-fired power production, replacing two-thirds of that production with renewable energy and imposing a new economy-wide price on GHG emissions of $20 per tonne on January 1, 2017, rising to $30 per tonne on January 1, 2018. The Alberta Government also announced a new overall annual emissions limit of 100 megatonnes for the oil sands industry. On November 1, 2016, the provincial government introduced Bill 25 – the *Oil Sands Emissions Limit Act*, which serves to implement the 100 megatonne limit for emissions from oil sands operations. It provides further clarity regarding the types of emissions that will be included and exempted from the calculation of the 100 megatonne limit, and gives the Lieutenant Governor in Council the ability to establish a system of GHG emission allowances and a regime for purchasing and trading the allowances. No further details of how the allowances will be allotted within the industry have yet been provided. The emission limit applies only to oil sands operations, and is not expected to increase the Company's operating costs.

The Panel also recommended replacing the SGER with a new *Carbon Competitiveness Regulation* that will require distributors of transportation and heating fuels to annually do one or more of the following in recognition that GHG emissions are created when their fuel products are combusted by their customers: (a) acquire and then retire emission performance credits or offset credits; or (b) make payments to a technology fund at a rate of $30 per tonne of GHGs for transportation and heating fuels sold and distributed in the province. The distributors are expected to pass on the costs of complying with the proposed Carbon Competitiveness Regulation to their customers. The Panel estimates these costs will require customers to pay an additional 7¢ per litre for regular gasoline and $1.68 Gigajoules for natural gas.

Emissions from flaring at oil and gas wells and facilities and from landfills will also be subject to a GHG emission levy starting at $20 per tonne in 2017 and increasing to $30 a tonne in 2018 and thereafter. Fuel gas consumed in operating oil and gas wells, pipelines and facilities will be subject to the $30 per tonne levy commencing January 1, 2023.

The Panel also recommended that the $30 per tonne levy increase annually at a rate equal to the rate of inflation plus 2% per year so long as the levy in Alberta does not significantly exceed carbon prices in comparable jurisdictions or any future national carbon standard.

The Panel recommended that new regulations require operators of facilities emitting more than 100,000 tonnes of GHGs per year to measure their facility's emissions intensity and then have AEP reward the lowest 25% of emitters in each industry by providing them with free emission permits which they can then trade or bank for future use. The remaining 75% of the emitters in each industry will be required annually to do one or more of the following: (a) reduce their actual emission intensity to the level of the lowest quartile of emitters; (b) acquire and retire emission performance credits, emission permits or offset credits in an amount that will bring their facility's emissions on a net basis within the lowest quartile of their industry; or (c) make payments to a technology fund at a rate of $30 per tonne for each tonne that their facility exceeds the baseline established by the lowest 25% of emitters within their industry.

The proposed Carbon Competiveness Regulation has not yet been released and how the lowest quartile of emitters within an industry will be established for facility's emitting 100,000 tonnes of GHGs or more per year has not been announced. Further, the number of free permits to be given to the lowest quartile and the extent to which facilities in the lowest quartile will be able to trade or bank such permits is not yet known.

Methane emission reduction in the oil and gas industry is also a key to Alberta's new GHG emission plan with a goal of reducing oil and gas methane emissions by 45% by 2025. The Panel has made two recommendations in this regard. First, if adopted by the government, new design specifications will be put in place by the AER over the next several years for oil and gas wells, pipelines and facilities as well as standards for key equipment and operational best practices. Fugitive emission standards will also be included in the regulatory requirements and will require raising current standards for performance, monitoring, measurement and reporting.

Second, the Panel recommended that regulators, the oil and gas industry, independent experts and environmental groups collaborate to develop and oversee a multi-year plan for updating or retrofitting methane emitting equipment in existing facilities before the end of the equipment's useful life. The plan's specifics have not yet been announced, but the work would be aimed at creating an offset trading system whereby operators who take early action in retiring methane-emitting equipment can be rewarded. The Panel recommended that at the end of five years, or longer if there is evidence of cost effectiveness, the government should mandate the replacement of such equipment at facilities that have not participated in the offset program before the end of the equipment's life. The alternative to such methane emitting-equipment replacement will be to prematurely shut in and abandon the well or facility which uses such equipment.

One of the first steps to implement the Plan will be taken through the *Climate Leadership Implementation Act* ("**CLIA**"), which came into effect on January 1, 2017 through the *Climate Leadership Act* and the *Energy Efficiency Alberta Act*. The CLIA establishes the legislative framework for Alberta's carbon levy/tax. The carbon pricing regime has several key elements. First, it establishes an Alberta economy-wide carbon pricing regime in the form of a carbon levy on various types of fuel, at a rate of $20/tonne of GHG emissions for 2017 and a rate of $30/tonne for 2018 and subsequent years. Second, it outlines a rebate program which will offset the incremental costs of the carbon levy on qualifying households. Third, it will include a reduction to Alberta's small business corporate income tax rate from 3% to 2%. Finally, the carbon levy revenue will be used to fund initiatives to reduce GHG emissions, to support Alberta's ability to adapt to climate change and for rebates or adjustments related to the carbon levy to consumers, businesses, and communities, including the rebate program for households described above. The *Climate Leadership Regulation* was released on November 3, 2016 and provides further details regarding the implementation of the carbon pricing regime and the exemptions thereto. The new carbon pricing regime may increase the Company's operating costs.

To collect the carbon levy, the CLIA imposes payment and remittance obligations on persons throughout the fuel supply chain. The person responsible for paying, collecting or remitting the carbon levy depends on the type of fuel and its use. Typically persons that deal in bulk fuel, such as purchasers of fuel at refineries or terminals, importers of fuel into Alberta, or natural gas distributors will be obligated to remit the carbon levy. The CLIA and associated regulation provide mechanisms, either through exemption licenses or refunds, to permit fuel to move through the supply chain without incurring multiple incidences of carbon levy. In some cases, consumers will be obligated to self-assess the carbon levy (for example, oil and gas producers and midstreamers that vent or flare gas or who remove fuel from the supply chain for their own consumption).

British Columbia

Pursuant to the *Greenhouse Gas Reduction Targets Act* (the "**GGRTA**"), the Province of British Columbia has set a goal of reducing its GHG emissions to 33% below 2007 levels by 2020 and 80% below 2007 levels by 2050. The GGRTA requires the province to report every second year on the level of emissions reductions achieved in the province.

The Government of British Columbia implemented a carbon tax on the purchase or use of fossil fuels (e.g., gasoline, diesel, natural gas, heating oil, propane, and coal) within the province. Since July 1, 2012, the carbon tax rates have been $30 per tonne of CO_2 emissions. Because different fuels generate different amounts of GHG when burned, the $30 per ton of CO_2 equivalent is translated into different tax rates for each specific fuel type.

Since 2008, British Columbia has worked under its Climate Action Plan, which outlines a number of strategies and initiatives to help the province meet its goal of reducing GHG emissions. In May 2015, the province created the Climate Leadership Team to review economic development options, review GHG emissions reductions, and to make recommendations for the new Climate Leadership Plan, which will replace the old Climate Action Plan. The province also released a discussion paper for public comment regarding British Columbia's future climate-change policies. The discussion paper outlines the province's achievements under the current plan and sets out its climate change principles and high-level goals for the new plan. The Climate Leadership Plan is comprised of the following elements:

- The Climate Leadership Plan will not increase the carbon tax rate, leaving the tax rate at $30 per tonne of CO_2 equivalent emissions.

- The Climate Leadership Plan affects electricity and gas utilities. In the future, any electricity acquired by BC Hydro that is not from a clean or renewable energy source must be approved by the government through an Integrated Resource Plan, where it will be aligned with specific reliability or cost concerns.

- The Climate Leadership Plan aims to reduce emissions from the transportation sector. The New Plan renews the Clean Energy Vehicle program which incentivizes the purchase of clean energy vehicles and scrapping of older, less energy-efficient vehicles. It also incentivizes the conversion of commercial vehicle fleets to renewable natural gas, and will increase the Low Carbon Fuel Standard to 15% by 2020.

The Climate Leadership Plan also establishes a methane emissions reduction strategy to reduce fugitive and vented emissions by 45% from current levels by 2025.

The *Greenhouse Gas Reduction (Cap and Trade) Act* and accompanying Reporting Regulation was repealed by the Greenhouse Gas Industrial Reporting and Control Amendment Act (the **"GGIRCA**") effective January 1, 2016. The Greenhouse Gas Emission Reporting Regulation provides the statutory framework for operations reporting emissions for the 2016 reporting year. The GGIRCA is an emissions intensity based system and requires any facility that emits 10,000 tonnes or more of carbon dioxide equivalent per year to report their emissions on an annual basis. Like the SGER, facility operators are able to meet the GGIRCA's requirements in various ways, such as: (1) purchasing funded units; (2) earning offset units via verified reduction of GHG emissions; (3) earning credits for each tonne of GHG emissions below the emissions limit; and (4) earning recognized units from another jurisdiction, to be determined under regulations under the GGIRCA. There are three enabled Regulations in force, which are The Administrative Penalties and Appeals Regulation, the Control Regulation, and the Report Regulation.

Québec

The province of Québec operates under its 2013 – 2020 Climate Change Action Plan ("**Québec Climate Plan**"), which calls for a 20% reduction in GHG emissions below 1990 levels by 2020. The Québec Climate Plan includes fuel oil energy efficiency measures, measures to encourage cleaner energy alternatives and tightened fuel oil sulphur level standards. As part of the overall Québec Climate Plan, the province has passed the Environmental Quality Act, which empowers the Government to set emission limits, establish reporting requirements for GHG emitters and also enables it to take part in the implementation of a cap-and-trade system.

In June 2016, the Québec Minister of Sustainable Development, Environment, and the Fight Against Climate Change introduced Bill 102 (An Act to amend the Environmental Quality Act to modernize the environmental authorization scheme and to amend other legislative provisions, in particular to reform the governance of the Green Fund), which aims to modernize the environmental authorization scheme in the Environment Quality Act, which will impact the environmental assessment procedure and authorization of industrial projects in Québec. Bill 102 has gone through first reading and will likely not be in force until late 2016 or early 2017 and may be subject to various amendments before adoption.

Under the current Environmental Quality Act, the government initially set a global GHG emission ceiling for all targeted emitters. The ceiling will gradually drop over time and achieve absolute reductions in GHG. Regulated businesses are required to monitor their GHG emissions as of January 1, 2013. The government may award a number of free emission units or "allocations" that take account of the historical level of a company's emissions and production. The number of free allocated units will gradually drop between 1 – 2% each year, which began in 2015. Businesses whose GHG emissions are higher than the number of units allocated will be required to modernize by adopting clean technologies, or by purchasing emission allowances (in the form of emission units, offset credits, or early reduction credits) at government auctions or on the carbon market. Businesses with GHG emissions below their allocation will be able to sell their excess carbon credits to other businesses on the carbon market.

The second cap-and-trade compliance period began January 1, 2015 whereby business operators in Québec that distribute fuel (such as gasoline, diesel fuel, propane, natural gas and fuel oil, with some exceptions) or import it for their own consumption and whose annual GHG emissions attributed to the use of fuel distributed and consumed in Québec equal or exceed an annual threshold of 25,000 metric tons of CO_2 equivalent will also be subject to the system. This second period ends on December 31, 2017.

On April 7, 2016, Québec released its comprehensive Energy Policy 2030 (**Policy 2030**). Policy 2030 seeks to significantly alter Québec's energy profile by 2030 through five main objectives: develop and favour a low-carbon economy, optimally develop energy resources, foster responsible consumption, capitalize on energy efficiency potential, and promote the entire technological and social innovation chain. Policy 2030 adopts several key targets which are: enhance energy efficiency by 15%, reduce the amount of petroleum products consumed by 40%, eliminate the use of thermal coal, increase overall renewable energy output by 25%, and increase bioenergy productions by 50%.

In December 2016, Bill 106, *An Act to implement the 2030 Energy Policy and to amend various legislative provisions* was passed by the Québec National Assembly. Bill 106 contemplates the enactment of the new *Petroleum Resources Act*, which will govern the development of petroleum resources while ensuring environmental protection, and optimal recovery of the resources in compliance with the GHG reduction targets set out by the government. It establishes a license and authorization system for the exploration, production, and storage of petroleum. The amendments also include the creation of Energy Transition Québec, an agency charged with implementing the government's clean energy plans to reduce GHG emissions to be 37.5% less than in 1990.

In September 2013, the California Air Resources Board, the California agency governing the state's cap-and-trade system and the government of Québec signed an agreement to harmonize and integrate the cap-and-trade systems of California and Québec. The agreement requires that the cap-and-trade regimes in California and Québec mutually recognize the emission credits and allowances issued by either jurisdiction. Accordingly, GHG emitters in both California and Québec will have the ability to purchase and sell emission allowances and carbon offset credits issued by either jurisdiction. Other key terms of the agreement include the development of a common electronic registry between the jurisdictions, mutual cooperation between the jurisdictions for enforcement purposes, and the holding of joint auctions of emission allowances using harmonized procedures. The agreement was implemented through the amendment of the Regulation respecting a cap-and-trade system for greenhouse gas emission allowances. The effect that Québec's GHG emission cap-and-trade system will have on the oil and gas industry in the province is uncertain at this time.

Québec is party to the Western Climate Initiative, which is an organization currently made up of the Provinces of British Columbia, Québec, Ontario, Manitoba and the State of California designed to assist in implementing GHG emissions trading programs. Within the Québec framework, businesses are obligated to remit to the government the emission allowances for each ton of GHG emitted. Without sufficient emission allowances, the company will be forced to purchase them on the carbon market. The objective is that a company will reduce its emissions to avoid the costs of purchasing emission allowances.

Québec has also enacted a carbon tax on the consumption of fossil fuels within the province under the Regulation respecting the annual duty payable to the Green Fund. Under this regulation, distributors must pay an annual duty to Québec's Green Fund according to the per tonne of carbon dioxide rate published in the Gazette officielle du Québec.

On August 31, 2015, at the 39th annual conference of New England Governors and Eastern Canadian Premiers, Québec adopted a resolution that aims to decrease carbon pollution by 35-45% below 1990 levels by 2030. Premiers from New Brunswick, Newfoundland and Labrador, Nova Scotia, Prince Edward Island, along with Governors from Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont also adopted the resolution. In the 2016 annual conference, another resolution was adopted for the jurisdictions to address climate change collaboratively and to require them to provide reports to the conference every two years.

Northwest Territories

In August 2011, the government of the Northwest Territories released A Greenhouse Gas Strategy for the NWT 2011-2015, which seeks to stabilize GHG emissions at 2005 levels by 2015, to limit GHG emission increases to 66% above 2005 levels by 2020, and to return GHG emissions to 2005 levels by 2030. The government plans to release a new climate change framework and energy strategy in the spring of 2017, and is currently conducting workshops and public information sessions for the project.

CAPITAL STRUCTURE AND OUTSTANDING SECURITIES

Share Capital

The authorized share capital of Prairie Provident consists of an unlimited number of Common Shares, of which 115,402,880 Common Shares are issued and outstanding as of the date of this AIF as fully paid and non-assessable shares.

Holders of Common Shares are entitled to receive notice of and to vote (on the basis of one vote for every share held) at meetings of Prairie Provident shareholders, and subject any priorities attaching to any future class of shares, the right to receive any dividend declared by Prairie Provident and to share rateably in any distribution of its remaining property on dissolution.

The Common Shares are the only voting securities of Prairie Provident.

Dividends

Prairie Provident has not paid any dividends on the Common Shares. Future dividends, if any, will be at the discretion of the Board of Directors, and any decision in respect thereof will be made based on the Company's operating results, cash flow, financial condition and funding requirements for ongoing operations and capital expenditures, and such other business factors and considerations as the Board of Directors considers relevant.

Prairie Provident does not anticipate paying dividends in the near term as cash flow will be reinvested in the Company's assets and operations.

The Company's credit facility includes negative covenants that restrict Prairie Provident from paying dividends on its Common Shares.

Convertible Securities

As of the date hereof, the only outstanding securities of Prairie Provident that are exercisable for or convertible into Common Shares are: (i) 471,332 performance share units ("**PSUs**"), each of which entitles the holder to receive, on settlement in December 2018 (as to 114,427 PSUs) or December 31, 2019 (as to 354,905 PSUs), up to two Common Shares or the cash equivalent thereof, subject to satisfaction of applicable performance conditions attached thereto; (ii) 2,621,969 incentive stock options ("**Options**"), each of which is exercisable for one Common Share at an exercise price of $0.76 (as to 752,174 Options) and $0.96 (as to 1,869,795 Options) per share, subject to vesting in accordance with its terms; and (iii) the 2,985,500 Warrants distributed pursuant to Prairie Provident's bought deal equity financing completed on March 16, 2017. Each Warrant entitles the holder to acquire one Common Share at an exercise price of $0.87 per share (subject to adjustment in certain circumstances) until March 16, 2019. All of the PSUs and Options are held by directors, officers and employees.

Escrow

To the knowledge of the directors and executive officers of the Company, there are no securities of Prairie Provident held in escrow or subject to a contractual restriction on transfer.

Market for Securities

The Common Shares commenced trading on the TSX on September 16, 2016, following completion of the Arrangement, under the symbol "PPR".

Price Range and Trading Volume

The following table sets out the reported high and low trading prices (which are not necessarily the closing prices) and aggregate trading volumes for the Common Shares on the Toronto Stock Exchange, as reported by TMX Datalinx, for the periods indicated.

	Price Range ($)		
	High	**Low**	**Trading Volume**
September 16-30, 2016 [(1)]	1.25	0.82	612,793
October 2016	0.98	0.84	1,037,165
December 2016	0.85	0.68	1,867,685
January 2017	0.80	0.70	2,043,427
February 2017	0.78	0.67	1,747,667
March 1 – 29, 2017	0.70	0.59	2,433,397

Note:

(1) The Common Shares commenced trading on the TSX on September 16, 2016.

Prior Sales

Pursuant to the completion of the Arrangement on September 12, 2016, Prairie Provident issued 74,730,618 Common Shares to former Lone Pine shareholders and 22,678,817 Common Shares to former Arsenal shareholders. The Arrangement also provided for the issuance of replacement restricted share units to former holders of restricted share units of Lone Pine, all of which were subsequently settled in accordance with the Arrangement through the issuance of 903,359 Common Shares and 84,086 Common Shares on October 3, 2016 and January 31, 2017, respectively.

On September 26, 2016, Prairie Provident granted 116,427 PSUs, each of which entitles the holder to receive, on settlement in December 2018, up to two Common Shares or the cash equivalent thereof, subject to satisfaction of applicable performance conditions attached thereto, and 752,174 Options, each of which is exercisable for one Common Share at an exercise price of $0.96 per share, subject to vesting in accordance with its terms and to expiry in 2021, all pursuant to its equity incentive plans.

On December 16, 2016, the Company completed a public offering of 5,465,000 Common Shares issued on a flow-through basis with respect to Canadian exploration expenses at a price $0.85 per share, and 375,000 Common Shares issued on a flow-through basis with respect to Canadian development expenses at a price of $0.80 per share.

On January 27, 2017, Prairie Provident granted 354,905 PSUs, each of which entitles the holder to receive, on settlement in December 2019, up to two Common Shares or the cash equivalent thereof, subject to satisfaction of applicable performance conditions attached thereto, and 1,869,795 Options, each of which is exercisable for one Common Share at an exercise price of $0.76 per share, subject to vesting in accordance with its terms and to expiry in 2022, all pursuant to its equity incentive plans.

On March 16, 2017, the Company completed a public offering of 5,195,000 Common Shares issued on a flow-through basis with respect to Canadian exploration expenses at a price $0.77 per share, and 5,971,000 subscription receipts at a price of $0.67 per subscription receipt. All such subscription receipts were, pursuant to their terms, automatically exchanged, without payment of any additional consideration, for 5,971,000 Common Shares and 2,985,500 Warrants in connection with closing of the Acquisition on March 22, 2017. Each Warrant entitles the holder to acquire one Common Share at an exercise price of $0.87 per share (subject to adjustment in certain circumstances) until March 16, 2019.

DIRECTORS AND OFFICERS

The following table sets out the names of our directors and executive officers, their jurisdictions of residence, their positions or offices with Prairie Provident and the period during which they have served in such capacities (or in the same capacity with Lone Pine prior to the Arrangement, and their principal occupations during the last five years.

Name, Jurisdiction of Residence and Position with Prairie Provident	**Principal Occupations for Past Five Years**	**Director and/or executive officer since**
Patrick McDonald[(1)] Colorado, USA *Chairman of the Board*	Chief Executive Officer of Carbon Natural Gas Company (oil and gas exploration and production) since 2011 and of its predecessor, Nytis Exploration, since 2004; prior to its business combination with Sabine Oil & Gas LLC in December 2014, Chief Executive Officer of Forest Oil Company (oil and gas exploration and production) since September 2012 and its Interim Chief Executive Officer since June 2012	March 2011
Tim Granger[(1)] Alberta, Canada *President, Chief Executive Officer and a Director*	President and Chief Executive Officer of the Company since April 2013; prior thereto, Chief Executive Officer and Managing Director of Molopo Energy Limited (oil and gas exploration and production) from January 2012 to January 2013; prior thereto, President and Chief Executive Officer of Compton Petroleum Company (oil and gas exploration and production) from January 2009 to December 2011	April 2013
David Fitzpatrick [(1)(3)(4)] Alberta, Canada *Director*	President and Chief Executive Officer of Veresen Midstream (natural gas and NGL processing) since July 2015; Chairman of Eagle Energy Inc. (oil and gas exploration and production) since March 2008; Director of Twin Butte Energy Ltd. (oil and gas exploration and production) from July 2008 to September 2016; Interim Chief Executive Officer of Lone Pine from February 2013 to April 2013	June 2011
Terence (Tad) Flynn [(2)(4)(5)] New York, USA *Director*	Managing Director, Financial Advisory Services, and head of Asset Management Services of Houlihan Lokey (investment bank) since April 2009	January 2014
Derek Petrie [(3)(4)(5)] Alberta, Canada *Director*	President of R2 Design & Manufacturing (oilfield services and equipment) since February 2016; prior thereto, retired businessman from April 2014 to February 2016; prior thereto, director of T&T Inspections & Engineering Ltd. (division of Hyduke Energy Services) (oilfield services) since February 2014; prior thereto, General Manager for Do All Industries (fabricating and engineering services to the drilling industry) from September 2012 to February 2014; prior thereto, General Manager at Mastco Derrick Services Ltd. (drilling rig fabricator) from 2000 to September 2012	September 2016
Ajay Sabherwal [(2)(3)(5)] Washington, DC, USA *Director*	Chief Financial Officer of FTI Consulting, Inc. (business advisory services) since August 2016; prior thereto, Executive Vice President and Chief Financial Officer of FairPoint Communications, Inc. (telecommunications) from July 2010 to August 2016	January 2014

Name, Jurisdiction of Residence and Position with Prairie Provident	**Principal Occupations for Past Five Years**	**Director and/or executive officer since**
Rob Wonnacott (2)(3)(4) Alberta, Canada *Director*	Partner and Director of Value Point Capital (private equity investment) since 2010; Principal of NVB Financial Corp. (financial advisory) since 2015; Chief Executive Officer of Pendo Petroleum Inc. (oil and gas exploration and production) from June 2012 to July 2013; prior thereto, Chief Financial Officer of Grizzly Oil Sands ULC (bitumen development company) from January to June 2011	September 2011
Mimi Lai Alberta, Canada *Vice President, Finance and Chief Financial Officer*	Vice President, Finance and Chief Financial Officer since September 2016; prior thereto, Vice President, Finance of the Company since January 1, 2015; prior thereto, Controller of Lone Pine since May 2014; prior thereto, Manager, Financial Reporting at Harvest Operations Corp. (oil and gas exploration and production) from January 2011 to May 2014	January 2015
Robert (Bob) Guy Alberta, Canada *Vice President, Operations*	Vice President, Operations of the Company since January 2016; prior thereto, consultant to Lone Pine since June 2015; prior thereto, Senior Client/Project Manager for an engineering consulting firm from November 2014 to June 2015; prior thereto, Vice President, Production Operations at Spyglass Resources Corp. (formerly AvenEx Energy Corp.) from August 2006 to August 2014	January 2016
Gjoa Taylor Alberta, Canada *Vice President, Land*	Vice President, Land of the Company since September 12, 2016; prior thereto, Vice President, Land of Arsenal since February 2008	September 2016
Tony van Winkoop Alberta, Canada *Vice President, Exploration*	Vice President, Exploration of the Company since September 12, 2016; prior thereto, President and Chief Executive Officer of Arsenal since July 2007	September 2016

Notes:

(1) Member of the Executive Committee of the Board of Directors, consisting of Messrs. McDonald (Chair), Granger and Fitzpatrick.

(2) Member of the Audit Committee of the Board of Directors, consisting of Messrs. Sabherwal (Chair), Flynn and Wonnacott. See "*Audit Committee Information*" below.

(3) Member of the Reserves Committee of the Board of Directors, consisting of Messrs. Wonnacott (Chair), Fitzpatrick, Petrie and Sabherwal.

(4) Member of the Compensation Committee of the Board of Directors, consisting of Messrs. Fitzpatrick (Chair), Flynn, Petrie and Wonnacott.

(5) Member of the Nominating and Corporate Governance Committee of the Board of Directors, consisting of Messrs. Flynn (Chair), Petrie and Sabherwal.

The term of office of each director expires at the next annual meeting of Prairie Provident's shareholders, which is scheduled to be held on May 18, 2017.

As of the date hereof, the directors and executive officers of the Company, as a group, beneficially own or control or direct, directly or indirectly, an aggregate of 1,912,585 Common Shares, representing approximately 1.7% of the outstanding Common Shares (calculated on an undiluted basis).

Messrs. McDonald, Fitzpatrick and Wonnacott were directors of, and Mr. Granger was an executive officer and director of, one or more members of the Lone Pine Group at the time that the proceedings which concluded on January 31, 2014 with the successful implementation of the Restructuring Plan were first commenced under the *Companies' Creditors Arrangement Act* (Canada) and Chapter 15 of the United States Bankruptcy Code, the Creditor Protection Proceedings were commenced, and continued in such capacities through implementation of the Restructuring Plan. Mr. McDonald was President and Chief Executive Officer of Forest Oil Corporation at the time of its business combination with Sabine Oil & Gas LLC in December 2014, and continued as a director of that corporation (renamed Sabine Oil & Gas Corporation) until July 2016. In July 2015, Sabine Oil & Gas Corporation and certain of its subsidiaries commenced proceedings under Chapter 11 of the United States Bankruptcy Code. From August 2010 through August 2016, Mr. Sabherwal was Executive Vice President and Chief Financial Officer of FairPoint Communications, Inc., which commenced proceedings under Chapter 11 of the United States Bankruptcy Code in October 2009 and completed its reorganization thereunder in January 2011. From November 2005 through March 2009, Mr. Sabherwal was Chief Financial Officer of Aventine Renewable Energy Holdings, Inc., which commenced proceedings under Chapter 11 of the United States Bankruptcy Code in April 2009 and completed its reorganization thereunder in March 2010. Mr. Fitzpatrick resigned as a director of Twin Butte Energy Ltd. in September 2016 concurrently with the appointment of a receiver and manager over that company's assets on application by its lenders.

There are potential conflicts of interest to which our directors and officers may become subject in connection with the Company's operations. In particular, certain of our directors have managerial or director positions with other oil and gas companies whose business could compete or interests could conflict with those of the Company, or that may provide financing or services to competitors. Conflicts, if any, will be subject to the procedures and remedies provided under the ABCA. In accordance with the ABCA, any director or officer who is a party to a material contract or material transaction (actual or proposed) with the Company, or is a director or officer of or has a material interest in any person who is a party to a material contract or material transaction (actual or proposed) with the Company, must disclose his or her interest, and is generally prohibited from voting on any resolution to approve the contract or transaction. See also "*Risk Factors – Potential Conflicts of Interest*".

AUDITOR INFORMATION

The auditors of the Company are Ernst & Young LLP, Chartered Professional Accountants, Calgary, Alberta, which firm has served as the auditors of the Company (having been first appointed as auditors of Lone Pine) since 2011.

Ernst & Young LLP is independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

External Auditor Service Fees

Following is a summary of the professional service fees billed by Ernst & Young LLP, fiscal years ended December 31, 2016 and 2015 for audit and other services.

	2015	**2016**
Audit Fees (1)	$246	$282
Audit-Related Fees (2)	$–	$256
Tax Fees (3)	$114	$52
All Other Fees	$2	$2
Total Fees	$363	$592

Notes:

(1) Audit Fees were paid, or were payable for the audit of Lone Pine's annual financial statements and the reviews of Lone Pine's quarterly financial statements.

(2) Audit-Related Fees are fees for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements are not reported as "audit fees".

(3) Tax Fees were fees paid or payable for corporate tax return filings, tax advice and tax planning services.

(4) All Other Fees were paid for subscriptions to auditor-provided and supported tools.

RISK FACTORS

The Company is exposed to a number of risks inherent in exploring for, developing and producing crude oil, natural gas and NGLs, some that impact the oil and gas industry as a whole and others that are unique to our operations. This section describes the important risks and other matters that could cause actual results to differ materially from those reflected in forward-looking statements. The impact of any risk or a combination of risks may adversely affect, among other things, our business, reputation, financial condition, results of operations and cash flows. The risks described below may not be the only risks that the Company faces, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. When assessing the materiality of the following risk factors, the Company takes into account a number of qualitative and quantitative factors, including, among others, financial, operational, environmental, regulatory, reputation and safety aspects of the identified risk factor. Events or circumstances described below could materially and adversely affect our business, financial condition, results of operations or cash flows. The risks described below are interconnected, and more than one of these risks could materialized simultaneously or in short sequence if certain events or circumstances described below actually occur. If any of the following risks develop into actual events, our business, financial condition, cash flows or results of operations could be materially and adversely affected. The following risk factors should be read in conjunction with the other information contained herein.

Exploration, Development and Production Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by the Company will result in new discoveries of oil and natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory or development program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior wells or additional seismic data and interpretations thereof.

Ability to Find, Develop or Acquire Additional Reserves

Our future oil, natural gas and NGLs reserves and production, and therefore its cash flows, are highly dependent upon its success in exploiting its current reserves base and acquiring, discovering or developing additional oil and gas reserves that are economically recoverable. Without additions to reserves through exploration, acquisition or development activities, our production will decline over time as reserves are depleted.

The business of exploring for, developing or acquiring reserves is capital intensive. To the extent our cash flows from operations are insufficient to fund capital expenditures and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil, natural gas and NGL reserves will be impaired. In addition, there can be no certainty that we will be able to find and develop or acquire additional reserves to replace our production at acceptable costs.

Hydrocarbons are a limited resource, and the Company is subject to increasing competition from other companies, including national oil companies. Successful acquisitions require an assessment of a number of factors, many of which are uncertain. These factors include recoverable reserves, development potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. If a high impact prospect identified by the Company fails to materialize in a given year, our multi-year exploration or development portfolio may be compromised. See "*Risk Factors – Volatility of Crude Oil, Natural Gas and NGL Prices*" in this AIF. The recent decline in commodity prices, if sustained, may result in promising exploration and development projects being deemed uneconomic. Continued failure to achieve anticipated reserve and resource addition targets may result in our withdrawal from an area, which in turn may result in a write-down of any associated reserves and/or resources for that area.

Exploration and development drilling may not result in commercially productive reserves and, if production begins, reservoir performance may be less than projected. Future oil and gas exploration and development may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage, processing or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Volatility of Crude Oil, Natural Gas and NGL Prices

Our financial performance and condition are highly sensitive to the prevailing prices of crude oil, natural gas and NGL. Fluctuations in these prices could have a material effect on our operations and financial condition, the value of its oil and natural gas reserves and its level of expenditure for oil and gas exploration and development. Prices for liquids and natural gas fluctuate in response to changes in the supply of and demand for liquids and natural gas, market uncertainty and a variety of additional factors that are largely beyond our control. We currently use derivative instruments to hedge our expected base production so as to manage the impact of fluctuations in crude oil and natural gas prices. See "*Risk Factors – Losses Resulting from Hedging Activities*" in this AIF. Fluctuations in crude oil and gas prices could have a material effect on the volatility of our earnings. Oil prices are largely determined by international supply and demand. Factors which affect crude oil prices include, among others, the actions of the Organization of Petroleum Exporting Countries, world economic conditions, government regulation, political stability throughout the world, the foreign supply of crude oil, the price of foreign imports, the ability to secure adequate transportation for products which could be affected by pipeline constraints, the availability of alternative fuel sources, technological advances affecting energy production and consumption, and weather conditions. Historically, NGLs prices have generally been correlated with oil prices, and are determined based on supply and demand in international and domestic NGLs markets. Natural gas prices are impacted by North American inventory levels which have increased year-over-year due to production growth in North America.

The substantial and extended decline in the prices of crude oil, natural gas and NGLs have resulted in delay or cancellation of drilling, development or construction programs, and curtailment in production and/or unutilized long-term transportation and drilling commitments, all of which could have a material adverse impact on the Company. Oil and gas producers in Canada currently receive discounted prices for their production relative to certain international prices due to constraints on their ability to transport and sell such production to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by oil and gas producers, including the Company. Poor economics for developing assets have resulted in an industry-wide reduction of drilling activity which may lead to loss of leases and skilled workers. Moreover, changes in commodity prices may result in downward adjustments to our estimated reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require that the Company impair, as a non-cash charge to earnings, the carrying value of our oil and gas properties. The Company is required to perform impairment tests on oil and gas properties whenever events or changes in circumstances indicate that the carrying value of properties may not be recoverable. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and gas properties, the carrying value may not be recoverable and, therefore, an impairment charge will be required to reduce the carrying value of the properties to their estimated fair value. The Company may incur impairment charges in the future, which could materially affect our results of operations, and its balance sheet, in the period incurred.

The continued low commodity price environment affects our ability to access capital in a number of ways, which include, among others, the following:

- our ability to access new debt or credit markets on acceptable terms may be limited, and this condition may last for an unknown period of time;

- our bank credit facility limits the amounts it can borrow to a borrowing base amount, determined by the lenders in their sole discretion based on their valuation of our estimated reserves and their internal criteria;

- our bank credit facility limits our ratio of total debt to trailing 12-month Adjusted EBITDAX to no more than 3.0 to 1.0;

- we may be unable to obtain adequate funding under its bank credit facility because its lenders may simply be unwilling to meet their funding obligations; and

- the operating and financial restrictions and covenants in our bank credit facility limit (and any future financing agreements likely will limit) its ability to finance future operations or capital needs or to engage, expand or pursue our business activities.

Due to these and other factors, the Company cannot be certain that funding will be available, if needed and to the extent required, on acceptable terms, or at all. If funding is not available when needed, or if funding is available only on unfavorable terms, we may be unable to meet our obligations as they come due or be required to post collateral to support our obligations, or may be unable to meet our drilling commitments, implement our development plans, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues, results of operations or financial condition. Moreover, if we are unable to obtain funding to acquire additional properties containing proved reserves, our total level of estimated oil, natural gas and NGL reserves may decline, and we may be unable to maintain our level of production and cash flow.

Uncertainty of Reserve Estimates

The process of estimating oil and gas reserves is complex and involves a significant number of assumptions in evaluating available geological, geophysical, engineering and economic data. In addition, the process requires future projections of reservoir performance and economic conditions; therefore, reserves estimates are inherently uncertain. Since all reserves estimates are, to some degree, uncertain, reserves classification attempts to qualify the degree of uncertainty involved.

Since the evaluation of reserves involves the evaluator's interpretation of available data and projections of price and other economic factors, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on estimated uncertainty, and the estimates of future net revenue or future net cash flows prepared by different evaluators or by the same evaluators at different times may vary substantially. Our actual production, revenues, royalties, taxes, and development and operating expenditures with respect to its reserves will likely vary from such estimates and such variances could be material.

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

Net Present Value of Future Net Revenues

The net present value of future net revenues attributable to our reserves will not necessarily be the same as the current market value of their estimated reserves. Sproule based the estimated discounted future net revenues from proved reserves on certain commodity price assumptions, which assumptions are described in the notes to the reserves tables. Actual future net revenues from our properties will be affected by factors such as:

- actual prices received for oil, natural gas and NGLs;

- actual cost of development and production expenditures;

- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both production and incurrence of expenses in connection with the development and production of oil, natural gas and NGLs from the properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor used when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with Prairie Provident or the oil and natural gas industry in general. Additionally, such calculation excludes a number of important costs that Prairie Provident will actually incur, such as interest expense, income taxes and general and administrative expenses. Actual future prices and costs may differ materially from those used in the present value estimates included in this AIF.

Operational Risks

Our business is subject to all of the operating risks normally associated with the exploration for, development of and production of natural gas, oil and NGLs. These risks include blowouts, explosions, fire, gaseous leaks, migration of harmful substances and liquid spills, acts of vandalism and terrorism, any of which could cause personal injury, result in damage to, or destruction of, natural gas and oil wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations.

In addition, all of our operations will be subject to all of the risks normally incident to the transportation, processing, storing and marketing of natural gas, oil, NGLs and other related products, drilling and completion of natural gas and oil wells, and the operation and development of natural gas and oil properties, including encountering unexpected formations or pressures, premature declines of reservoir pressure or productivity, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of natural gas, oil or well fluids, adverse weather conditions, pollution and other environmental risks.

If any of these industry-operating risks occur, the Company could suffer substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations.

Insurance

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

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial governmental authorities impose road bans that restrict the movement of drilling and service rigs and other heavy equipment, thereby limiting or temporarily halting drilling and producing activities and other oil and gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also adversely affect our ability to meet drilling objectives and capital commitments, and may increase competition for equipment, supplies and personnel during the winter months, which could lead to shortages and increased costs or delay or temporarily halt operations.

Risks Related to Mergers and Acquisitions

The Company believes that possible future mergers or acquisitions may strengthen our position and create the opportunity to realize certain benefits, including, among other things, operational synergies and potential cost savings. Achieving the benefits of mergers or acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as being able to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations. Mergers and acquisitions could also result in difficulties in being able to hire, train or retain qualified personnel to manage and operate such properties.

Acquiring oil and gas properties requires the Company to assess reservoir and infrastructure characteristics, including estimated recoverable reserves, type curve performance and future production, commodity prices, revenues, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain and, as such, the acquired properties may not produce as expected, may not have the anticipated reserves and may be subject to increased costs and liabilities.

Although the acquired properties are reviewed prior to completion of an acquisition, such reviews are not capable of identifying all existing or potentially adverse conditions. This risk may be magnified where the acquired properties are in geographic areas where the Company has not historically operated or in new or emerging formations. New or emerging formations and areas often have limited or no production history and we may be less able to predict future drilling and production results over the life-cycles of the wells in such areas.

Further, the Company may not be able to obtain or realize upon contractual indemnities from the seller for liabilities created prior to an acquisition, and may be required to assume the risk of the physical condition of the properties that may not perform in accordance with expectations.

Capital Allocation and Project Decisions

Our long-term financial performance is sensitive to the capital allocation decisions taken and the underlying performance of the projects undertaken. Capital allocation and project decisions are undertaken after assessing reserve and production projections, capital and operating cost estimates and applicable fiscal regimes that govern the respective government take from any project. All of these factors are evaluated against common commodity pricing assumptions and the relative risks of projects. These factors are used to establish a relative ranking of projects and capital allocation, which is then calibrated to ensure the debt and liquidity of the Company is not compromised. However, material changes to project outcomes and deviation from forecasted assumptions, such as production volumes and rates, realized commodity price, cost or tax and/or royalties, could have a material impact on our cash flow and financial performance as well as assessed impacts of impairments on our assets. Adverse economic and/or fiscal conditions could impact the prioritization of projects and capital allocation to these projects, which in turn could lead to adverse effects such as asset under investment, asset performance impairments or land access expiries.

Project Delivery

Our ability to operate, generate sufficient cash flows, and complete projects depends upon numerous factors beyond our control. In addition to commodity prices and continued market demand for its products, these non-controllable factors include, among others, general business and market conditions, economic recessions and financial market turmoil, the overall state of the capital markets, including investor appetite for investments in the oil and gas industry generally and our securities in particular, the ability to secure and maintain cost effective financing for its commitments, legislative, environmental and regulatory matters, reliance on industry partners and service providers, unexpected cost increases, royalties, taxes, and volatility in oil, natural gas or NGL prices. Global demand for project resources can impact the access to appropriately competent contractors and construction yards as well as to raw products, such as steel. Typical execution risks include, among others, the availability of seismic data, the availability of pipeline and processing capacity, transportation interruptions and constraints, technology failures, accidents, reservoir quality, the availability and proximity of pipeline capacity, the availability of drilling and other equipment, the ability to access water for hydraulic fracturing operations, the ability to access lands, weather, unexpected cost increases, accidents, the availability of skilled labour, including engineering and project planning personnel, the need for government approvals and permits, and regulatory matters. Subsurface challenges can also result in additional risk of cost overruns and scheduling delays if conditions are not typical of historical experiences. The Company utilizes materials and services which are subject to general industry-wide conditions. Cost escalation for materials and services may be unrelated to commodity price changes and may continue to have a significant impact on project planning and economics. In addition, some of these risks may be magnified due to the concentrated nature of funding certain assets within our portfolio of oil and natural gas properties that are operated within limited geographic areas. As a result, a number of our assets could experience any of the same risks and conditions at the same time, resulting in a relatively greater impact on our financial condition and results of operations compared to other companies that may have a more geographically diversified portfolio of properties.

Declines in oil, natural gas or NGLs prices or a continued low price environment for natural gas, oil or NGLs create fiscal challenges for the oil and gas industry. These conditions have impacted companies in the oil and gas industry and our spending and operating plans and may continue to do so in the future. There may be unexpected business impacts from market uncertainty, including volatile changes in currency exchange rates, inflation, interest rates, defaults of suppliers and general levels of investing and consuming activity.

The Company manages a variety of projects, including exploration and development projects. Project delays may impact expected revenues and project cost overruns could make projects uneconomic.

All of our operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact our existing and planned projects.

Egress and Gas and Liquid Buyers

The Company delivers its products through gathering, processing and pipeline systems (some of which we do not own). The amount of oil and natural gas that we can sell is subject to the accessibility, availability, proximity and capacity of these systems. This access to market affects regional price differentials, which could result in the inability to realize the full economic potential of our production. Although transportation systems are expanding, the lack of firm transportation capacity continues to affect the industry and has the potential to limit the ability to produce and to market our production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil. North America has an integrated network of natural gas pipelines; however regional restrictions can arise resulting in curtailments. Any significant change in market factors, infrastructure regulation or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could negatively impact our business and, in turn, its financial condition, results of operations and funds from operations. A portion of our production is processed through third-party owned facilities that we do not 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 discontinuance or decrease of operations could adversely affect our ability to process its production and to deliver the same for sale.

Credit and Liquidity

Market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, may cause significant volatility of the credit markets, which may then restrict timely access and limit our ability to secure and maintain cost-effective financing on acceptable terms and conditions. In addition, if any lender under our syndicated bank credit facility does not fund its commitment, our liquidity may be reduced by an amount up to the aggregate amount of such lender's commitment. See "*Risk Factors – Counterparty Risk*" in this AIF. Further, our ability to access funds under its bank credit facility is based on a borrowing base, which is subject to periodic redeterminations based on our estimated reserves and prices that will be determined by our lenders in their sole discretion using the pricing models determined by the lenders at such time.

Our ability to access the private and public equity and debt markets and complete future asset monetization transactions is also dependent upon oil, natural gas and NGL prices, in addition to a number of other factors, some of which are outside our control. These factors include, among others:

- the value and performance of our debt and equity securities;
- domestic and global economic conditions; and
- conditions in the domestic and global financial markets.

Recent credit concerns and related turmoil in the energy sector have had an impact on our business and access to capital, and we may face additional challenges if economic and financial market conditions worsen. The weakened economic conditions also may adversely affect the collectability of our trade receivables. For example, our accounts receivable are primarily from purchasers of our oil, natural gas and NGL production and other exploration and production companies that own working interests in the properties that we operate. This industry concentration could adversely impact our overall credit risk because our customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices and other conditions. Further, a credit crisis and turmoil in the financial markets in the future could cause our commodity derivative instruments to be ineffective in the event a counterparty is unable to perform its obligations or seeks bankruptcy protection.

Due to these factors, the Company cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms, or at all. If we are unable to access funding when needed on acceptable terms, we may not be able to implement our business plans, meet our capital commitments, take advantage of business opportunities, respond to competitive pressures or refinance our debt obligations as they come due, any of which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Operating Restrictions under our Credit Facility

The credit agreement governing our bank credit facility contains, and any future indebtedness that we incur may contain, restrictive covenants that will impose significant operating and financial restrictions on the Company, including restrictions on its ability to, among other things:

- sell assets, including equity interests in its subsidiaries;
- pay dividends on, redeem or repurchase Prairie Provident shares;
- make investments other than the ownership and related operation of oil and gas properties and assets in Canada;
- incur or guarantee additional indebtedness or issue preferred shares;
- create or incur certain liens;
- make certain acquisitions and investments;
- enter into agreements that restrict distributions or other payments from restricted subsidiaries to Prairie Provident;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;

- enter into certain sale and leaseback transactions that are in excess of $5,000,000; and

- engage in certain business activities.

In addition, the credit agreement governing our bank credit facility provides that it will not permit its ratio of total debt outstanding to Adjusted EBITDAX for a trailing 12-month period to be greater than 3.0 to 1.0. At December 31, 2016, this ratio was 1.2 to 1.0.

As a result of these covenants and restrictions, the Company will be limited in the manner in which we conducts our business, and may therefore be unable to engage in favorable business activities or finance future operations or capital needs. Our ability to comply with these covenants and restrictions in the future is uncertain and will be affected by the levels of cash flows from its operations and events or circumstances beyond its control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired.

The credit agreement governing our bank credit facility also limits the amounts it can borrow to a borrowing base amount, determined by the lenders in their sole discretion taking into account the estimated value of our oil and gas properties. Outstanding borrowings in excess of the borrowing base must be repaid with interest. If the Company does not have sufficient funds on hand for such repayment, we may be required to seek a waiver or amendment from our lenders, refinance our bank credit facility, sell assets or issue debt or equity. The Company may not be able to obtain such financing or complete such transactions on acceptable terms, or at all. Failure to make any required repayment could result in an event of default under the credit agreement governing our bank credit facility.

A failure to comply with the requirements of the agreement governing our bank credit facility or any future indebtedness could result in an event of default under the agreement, which, if not cured or waived, could have a material adverse effect on our business, financial condition, cash flows and results of operations. If an event of default under the credit agreement governing our bank credit facility occurs and remains uncured, the lenders thereunder:

- would not be required to lend any additional amounts to the Company;

- could elect to declare all borrowings outstanding, together with accrued and unpaid interest thereon and fees, to be immediately due and payable;

- may require the Company to apply all available cash to repay these borrowings; or

- may prevent the Company from making debt service payments under other agreements.

Our level of indebtedness could affect our operations by:

- requiring the Company to dedicate a portion of cash flows from operations to service indebtedness, thereby reducing the availability of cash flow for other purposes;

- reducing our competitiveness compared to similar companies that have less debt;

- limiting our ability to obtain additional future financing for working capital, capital investments and acquisitions;

- limiting our flexibility in planning for, or reacting to, changes in our business and industry; and

- increasing our vulnerability to general adverse economic and industry conditions.

Our ability to meet and service our debt obligations depends on future performance. General economic conditions, natural gas, oil or NGL prices, and financial, business and other factors affect our operations and future performance. Many of these factors are beyond our control. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance debt or repay debt with proceeds from an offering of securities or sale of assets. No assurance can be given that the Company will be able to generate sufficient cash flow to pay the interest obligations on our debt, or that funds from future borrowings, equity financings or proceeds from the asset sales will be available to pay or refinance our debt, at all or on acceptable terms. Further, future acquisitions may decrease our liquidity by using a significant portion of available cash or borrowing capacity to finance such acquisitions, and such acquisitions could result in a significant increase in our interest expense or financial leverage if the Company incurs additional debt to finance the acquisitions.

Ownership of the Common Shares.

The market price of our Common Shares is sensitive to a variety of market based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates and the comparability of the Common Shares to other yield oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

There may be future dilution to our Shareholders. One of our objectives is to continually add to our reserves through acquisitions and through development. Our success in growth from acquisitions and development may, in part, depend on our ability to raise capital from time to time by selling additional Common Shares. Shareholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Common Shares issued to acquire those assets. Shareholders may also suffer dilution in connection with future issuances of Common Shares to effect acquisitions.

Sale of Additional Securities

The Company may issue an unlimited number of additional Common shares and other securities in the future to finance its activities without the approval of shareholders. Subject to the policies of the TSX, the Board of Directors has the discretion to set the price and terms of the issuance of any such additional securities, and any issuance of additional securities may have a dilutive effect on the holders of Common Shares.

Major Incident, Major Spill / Loss of Well Control

Oil and gas drilling and producing operations are subject to many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome, including, among others, the risk of fire, explosions, mechanical failure, pipe or well cement failure, well casing collapse, pressure or irregularities in formations, chemical and other spills, unauthorized access to hydrocarbons, illegal tapping of pipelines, accidental flows of oil, natural gas or well fluids, sour gas releases, contamination, vessel collision, structural failure, loss of buoyancy, storms or other adverse weather conditions and other occurrences. If any of these should occur, the Company could incur legal defence costs and remedial costs and could suffer substantial losses due to injury or loss of life, human health risks, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, unplanned production outage, cleanup responsibilities, regulatory investigation and penalties, increased public interest in our operational performance and suspension of operations. Our application of horizontal and multi-stage hydraulic fracture stimulation techniques involve greater risk of mechanical problems than vertical and shallow drilling operations.

Health Hazards and Personal Safety Incidents

The employee and contractor personnel involved in exploration and production activities and operations of the Company are subject to many inherent health and safety risks and hazards, which could result in occupational illness or health issues, personal injury, and loss of life, facility quarantine and/or facility and personnel evacuation.

Regulatory Approvals / Compliance and Changes to Laws and Regulations

Our exploration and production operations are subject to extensive regulation at many levels of government, including municipal, state, provincial and federal governments, and operations are subject to interruption or termination by governmental and regulatory authorities based on environmental or other considerations. Moreover, the Company has incurred and will continue to incur costs in our efforts to comply with the requirements of environmental, safety and other regulations. Further, the regulatory environment in the oil and gas industry could change in ways that we cannot predict and that might substantially increase our costs of compliance and, in turn, materially and adversely affect our business, results of operations and financial condition.

Failure to comply with the applicable laws or regulations may result in significant increases in costs, fines or penalties and even shutdowns or losses of operating licences or criminal sanctions. If regulatory approvals or permits required for operations are delayed or not obtained, the Company could experience delays or abandonment of projects, decreases in production and increases in costs. This could result in our inability to fully execute the Company's strategy and adversely impact our financial condition. See "*Risk Factors – Socio-Political Risks*" in this AIF.

Changes to existing laws and regulations or new laws could have an adverse effect on our business by increasing costs, impacting development schedules, reducing revenue and cash flow from natural gas and oil sales, reducing liquidity, limiting operations or otherwise altering the way the Company conducts business. There have been various proposals to enact new, or amend existing, laws and regulations relating to greenhouse gas emissions, hydraulic fracturing (including associated additives, water use, induced seismicity, and disposal) and shale gas development generally. See "*Risk Factors – Environmental Risks*" in this AIF.

The Company continues to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact on our operations. Governmental actors unilaterally control the timing, scope and effect of any currently proposed or future laws or regulations, and such enactments are subject to a myriad of factors, including political, economic and social pressures. The direct and indirect costs of such laws and regulations (if enacted) could materially and adversely affect our business, results of operations and financial condition.

Fiscal Stability

Governments may amend or create new legislation that could impact our operations and that could result in increased capital, operating and compliance costs. Moreover, our operations are subject to various levels of taxation in the jurisdictions in which the Company operates. Federal, provincial and territorial income tax rates or incentive programs relating to the oil and gas industry in the jurisdictions where we operate may in the future be changed or interpreted in a manner that could materially affect the economic value of the relevant assets. For example, the Alberta Government recently announced the results of a royalty review. While many details of the implementation of the new regime have yet to be determined, royalties on existing wells are to remain unchanged for 10 years, and the new royalties will apply only to wells drilled in 2017 and onwards. Furthermore, the Alberta Government has pledged that the new system will be, in aggregate, "rate of return neutral" relative to the existing system, although individual assets may see higher or lower royalties. The impact of the new royalty regime to the Company has not yet been fully evaluated.

Stakeholder Opposition

Our planned activities may be adversely affected if there is strong community opposition to its operations. For example, there is heightened public concern regarding hydraulic fracturing in parts of North America, which could materially affect our shale operations. In some circumstances, this risk of community opposition may be higher in areas where Prairie Provident operates alongside indigenous communities who may have additional concerns regarding land ownership, usage or claim compensation.

Non-Operatorship and Partners Relations

Some of our projects are conducted through, joint ventures, partnerships or other arrangements, where Prairie Provident has a limited ability to influence or control operations (or their associated costs) or future development, safety and environmental standards and amount of capital expenditures. Companies which operate these properties may not necessarily share our health, safety and environmental standards or strategic or operational goals or approach to partner relationships, which may result in accidents, regulatory noncompliance, project delays or unexpected future costs, all of which may affect the viability of these projects and our standing in the external market. Our dependence on the operator and other working interest owners for these properties and assets, and its limited ability to influence operations and associated costs, could materially adversely affect our financial performance. The success and timing of our activities on assets operated by others therefore will depend upon a number of factors that are outside of our control, including timing and amount of capital expenditures, timing and amount of operating and maintenance expenditures, the operator's expertise and financial resources, approval of other participants, selection of technology and risk management practices.

If these co-participants do not approve or are unable to fund their contractual share of certain capital or operating expenditures, suspend or terminate such arrangements or otherwise fulfill their obligations, this may result in project delays or additional future costs to the Company, all of which may affect the viability of such projects.

These co-participants may also have strategic plans, objectives and interests that do not coincide with and may conflict with those of the Company. While certain operational decisions may be made solely at our discretion as operator of certain projects, major capital and strategic decisions affecting such projects may require agreement among the co-participants. While the Company and its co-participants generally seek consensus with respect to major decisions concerning the direction and operation of the project assets, no assurance can be provided that the future demands or expectations of any party, including the Company, relating to such assets will be met satisfactorily or in a timely manner. Failure to satisfactorily meet such demands or expectations may affect our or its co-participants' participation in the operation of such assets or the timing for undertaking various activities, which could negatively affect our operations and financial results. Further, the Company is involved from time to time in disputes with its co-participants and, as such, we may be unable to dispose of assets or interests in certain arrangements if such disputes cannot be resolved in a satisfactory or timely manner.

Losses Resulting from Hedging Activities

The nature of our operations results in exposure to fluctuations in commodity prices. To reduce our exposure to fluctuations in oil, natural gas and NGL prices, the Company enters into derivative instruments (or hedging agreements) for a portion of its oil, natural gas and NGL production. We expects that our commodity hedging agreements will be limited in duration, usually for periods of three years or less; however, in conjunction with acquisitions, we may enter into or acquire hedges for longer periods. The terms of our various hedging agreements may limit the benefit to the Company of commodity price improvements. We may also suffer financial loss if the Company is unable to produce natural gas, oil or NGLs, or if counterparties to our hedging agreements fail to fulfill their obligations under the hedging agreements.

Our hedging transactions will impact its earnings in various ways, known and unknown. Due to the volatility of commodity prices, the Company may be required to recognize mark-to-market gains and losses on derivative instruments, as the estimated fair value of our commodity derivative instruments is subject to significant fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period-to-period estimates and will be a function of the actual price of the commodities on the settlement date of the particular derivative instrument. The Company expects that commodity prices will continue to fluctuate in the future, and, as a result, our periodic financial results will be subject to fluctuations related to its derivative instruments.

Attraction, Retention and Development of Personnel

The success of the Company will depend in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the Company. The Company does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry has historically been intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. This includes not only key personnel at a senior level, but also individuals with the professional and technical skill sets critical for our business, particularly geologists, geophysicists, engineers, accountants and other specialists. Any deterioration of our corporate culture could adversely affect our operations and long-term success.

Information Systems

The Company has become increasingly dependent upon the availability, capacity, reliability and security of our information technology (IT) infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. We depend on various IT systems to estimate reserve quantities, process and record financial and operating data, analyze seismic and drilling information, and communicate with employees and third-party partners. Our IT systems are increasingly integrated in terms of geography, number of systems, and key resources supporting the delivery of IT systems. The performance of our key suppliers is critical to ensure appropriate delivery of key services. Any failure to manage, expand and update our IT infrastructure, any failure in the extension or operation of this infrastructure, or any failure by our key resources or service providers in the performance of their services could materially and adversely harm our business.

The ability of the IT function to support our business in the event of a disaster such as fire, flood or loss/denial of any of our data centres or major office locations and our ability to recover key systems from unexpected interruptions cannot be fully tested. There is a risk that, if such an event actually occurs, the business continuity plan may not be adequate to immediately address all repercussions of the disaster. In the event of a disaster affecting a data centre or key office location, key systems may be unavailable for a number of days, leading to inability to perform some business processes in a timely manner.

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 its competitive position. Further, disruption of critical IT services, or breaches of information security, could have a negative effect on our operational performance and earnings, as well as on our reputation.

The Company applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however these controls may not adequately prevent cyber-security breaches. There is no assurance that the Company will not suffer losses associated with cyber-security breaches in the future, and we may be required to expend significant additional resources to investigate, mitigate and remediate any potential vulnerabilities.

Claims, Litigation, Administrative Proceedings and Regulatory Actions

The Company may be subject to claims, litigation, administrative proceedings and regulatory actions. The outcome of these matters may be difficult to assess or quantify, and there cannot be any assurance that such matters will be resolved in our favour. If we are unable to resolve such matters favourably, the Company or its directors, officers or employees may become involved in legal proceedings that could result in an onerous or unfavourable decision, including fines, sanctions, monetary damages or the inability to engage in certain operations or transactions. The defense of such matters may also be costly and time consuming, and could divert the attention of management and key personnel from our operations. The Company may also be subject to adverse publicity associated with such matters, whether or not allegations are valid or we are ultimately found liable. As a result, such matters could have a material adverse effect on our reputation, financial position, results of operations or liquidity.

Securing and Maintaining Title to Properties

Our oil and gas properties are held in the form of licenses and leases and working interests in licenses and leases. If the Company or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse effect on our results of operations and business. In addition title to the properties can become subject to dispute and defeat our claim to title over certain of its properties. Furthermore, there may be legislative changes which affect title to the oil and gas properties we control that, if successful or made into law, could impair our activities on the properties and result in a reduction of the revenue received. Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. We are not aware that any material claims have been made in respect of our properties and assets; however, if a claim arose and was successful this could have an adverse effect on the Company and our operations.

Socio-Political Risks

Our operations may be adversely affected by political or economic developments or social instability in the jurisdictions in which it operates, which are not within our control, including, among other things, a change in crude oil, natural gas or NGL pricing policy and/or related regulatory delays, the risks of war, terrorism, abduction, expropriation, nationalization, renegotiation or nullification of existing concessions and contracts, difficulties in enforcing contractual terms, a change in taxation policies, economic sanctions, the imposition of specific drilling obligations, the imposition of rules relating to development and abandonment of fields, access to or development of infrastructure, jurisdictional boundary disputes, and currency controls.

Future Changes in Laws

Income tax laws, royalty regimes, environmental laws or other laws and regulations may in the future be changed or interpreted in a manner that adversely affects the Company or our securityholders. Changes to existing laws and regulations or the adoption of new laws and regulations could also increase our cost of compliance and adversely affect our business, financial position, cash flows or results of operations.

Controlling Shareholder

Goldman Sachs Asset Management, L.P. (GSAM) exercises control or direction, directly or indirectly, over 49,433,242 Common Shares representing approximately 42.8% of the total number of Common Shares (undiluted) outstanding at the date of this AIF. As such, GSAM currently holds a sufficient number of our voting securities to materially affect control of the Company, and in the absence of near unanimous disagreement by all other shareholders will, in accordance with applicable corporate and securities laws, be able to positively determine the outcome of any matter requiring shareholder approval by ordinary resolution, including the election and removal of directors. The support of GSAM will also be required for any matter requiring approval of the Prairie Provident shareholders by special resolution, such as amendments to the Company's articles, a sale of all or substantially all of the assets of the Company, and certain business combination transactions. No party is likely to make a take-over bid for the Common Shares or other acquisition proposal unless supported by GSAM. Although the interests of all shareholders are generally aligned, GSAM is entitled to act solely in its own interests in the exercise of its rights as a shareholder, whether those interests are consistent or conflict with (and any such conflict may be resolved against) the interests of the Company or any of its shareholders or other stakeholders. Any conflict between GSAM's interests and the interests of the Company or any of its shareholders or other stakeholders may be resolved contrary to the interests of the Company or its shareholders or other stakeholders.

In addition to the GSAM holdings, Goldman Sachs & Co. (GS&Co) beneficially owns or controls or directs, directly or indirectly, a further 14,791,376 Common Shares representing approximately 12.8% of the total number of Common Shares (undiluted) outstanding at the date of this AIF.

The Company understands that GSAM acts as the investment manager for clients of GSAM that are the beneficial owners of these Common Shares, being Goldman Sachs BDC, Inc., Lone Pine Luxembourg A Sarl and Goldman Sachs Long Short Credit Strategies Fund, and as such exercises control or direction over the shares. The Company further understand that GSAM and GS&Co are both wholly-owned subsidiaries of Goldman Sachs Group, Inc. GSAM's clients and GS&Co were shareholders of Lone Pine and received Common Shares pursuant to completion of the Arrangement.

Clients of GSAM and GS&Co (collectively, the "**Principal Holders**") were significant holders of senior notes and other unsecured debt of Lone Pine that was compromised under the Restructuring Plan implemented on January 31, 2014, pursuant to which they (together with other unsecured creditors) were issued common equity securities of Lone Pine in proportion to the principal amount of their compromised claims. The Principal Holders also provided backstop support for further capital investment provided under the Restructuring Plan and received a proportionate portion of a US$4 million backstop fee in partial consideration for their compromised debt claims. As participants in the future capital investment provided for under the Restructuring Plan, the Principal Holders subscribed for and purchased preferred equity securities of Lone Pine. Pursuant to the Arrangement, the Principal Holders received Common Shares in substitution for their Lone Pine securities on the same terms as were applicable to all other holders of such Lone Pine securities.

Exchange Rate Fluctuations

World oil prices are quoted in U.S. dollars. An increase (or decrease) in the exchange rate for the Canadian dollar versus the U.S. dollar would result in the receipt by the Company of fewer (or more) Canadian dollars for its production. Our expenses are primarily denominated in Canadian dollars. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar could impact our revenue and expenses and have an adverse effect on our financial performance and condition. The Company monitors and, when appropriate, uses derivative financial instruments to manage its exposure to currency exchange rate risk. Changes in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates may also impact the future value of the Company's reserves as determined by independent evaluators.

Counterparty Risk

The Company is exposed to the risks associated with counterparty performance including credit risk and performance risk. We may experience material financial losses in the event of customer payment default for commodity sales and financial derivative transactions. Our liquidity may also be impacted if any lender under our existing credit facilities is unable to fund its commitment. Performance risk can impact our operations by the non-delivery of contracted products or services by counterparties, which could impact project timelines or operational efficiency. Fluctuations in prevailing prices of crude oil, natural gas and NGLs could have a material adverse effect on the operations and financial condition of counterparties. The Company also has credit risk arising from cash and cash equivalents held with banks and financial institutions.

Interest Rates

The Company is exposed to interest rate risk principally by virtue of our borrowings. Borrowing at floating rates exposes the Company to movements in interest rates. Borrowing at fixed rates exposes the Company to reset risk associated with debt maturity. Variations in interest rates and schedule principal repayments could result in changes in the amount required to service debt, which may negatively impact our cash flows and financial condition.

Competitive Risk

The global oil and gas industry is highly competitive. The Company faces significant competition and many of our competitors have resources in excess of our available resources. We actively compete for the acquisition and divestment of properties, the exploration for and development of new sources of supply, the contractual services for oil and gas drilling and production equipment and services, the transportation and marketing of current production, and industry personnel, including, but not limited to, geologists, geophysicists, engineers and other specialists that enable the business. Many of our competitors have the ability to pay more for seismic and lease rights in crude oil and natural gas properties and exploratory prospects. They can define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. If we are not successful in the competition for oil and gas reserves or in the marketing of production, our financial condition and results of operations may be adversely affected. Many of our competitors have resources substantially greater than our and, as a consequence, the Company may be at a competitive disadvantage.

Income Taxes

Income tax laws, other laws or government incentive programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects the Company and our shareholders. Tax authorities having jurisdiction over the Company or our securityholders may disagree with how the Company calculates our income for tax purposes or tax liabilities or structure our arrangements, or could change their administrative practices, to the detriment of the Company or our securityholders. The Company is also subject to income tax audit and reassessment risks, the outcome of which may result in reduction in our tax pools, loss carry-forwards, or even cash tax liabilities. Reduction in our future income tax deductibility and any cash tax payable will lower our future cash flows and negatively impact its financial condition.

Environmental Risks

General

All phases of our oil, natural gas and NGL business are subject to environmental regulation pursuant to a variety of laws and regulations in the jurisdictions in which we do business (collectively, "environmental regulation").

Environmental regulation imposes, among other things, restrictions, liabilities and obligations in connection with the use, generation, handling, storage, transportation, treatment and disposal of chemicals, hazardous substances and waste associated with the finding, production, transmission and storage of our products, including the hydraulic fracturing of wells, the decommissioning of facilities and in connection with spills, releases and emissions of various substances to the environment. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and natural gas operations.

Environmental regulation also requires that wells, facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations including exploration and development projects and changes to certain existing projects may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties.

Although the Company currently believes that the costs of complying with environmental legislation and dealing with environmental civil liabilities will not have a material adverse effect on our financial condition or results of operations, there can be no assurance that such costs will not have such an effect in the future.

Our business is subject to the trend toward increased rigour in regulatory compliance and civil or criminal liability for environmental matters in Canada. Compliance with environmental legislation can require significant expenditures, and failure to comply with environmental legislation may result in the assessment of administrative, civil and criminal penalties, the cancellation or suspension of regulatory permits, the imposition of investigatory or remedial obligations or the issuance of injunctions restricting or prohibiting certain activities. Under existing environmental laws and regulations, the Company could be held strictly liable for the remediation of previously released materials or property contamination resulting from our operations, regardless of whether those operations were in compliance with all applicable laws at the time they were performed. Regulatory delays, legal proceedings and reputational impacts from an environmental incident could result in a material adverse effect on our business. Increased stakeholder concerns and regulatory actions regarding shale gas development could lead to third party or governmental claims, and could adversely affect our business and financial condition.

A number of federal, provincial and territorial governments have announced intentions to regulate greenhouse gases and certain air pollutants. These governments are currently developing the regulatory and policy frameworks to deliver on their announcements. The Canadian federal government has announced it will work with the provinces and territories to establish a pan-Canadian climate change framework that is consistent with the Paris Agreement. The Alberta government outlined its Climate Leadership Plan which includes four key areas, one of which is targeting a 45% reduction in methane gas emissions from oil and gas operations by 2025.

Hydraulic Fracturing

The Company utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated drilling fluids and other technologies in its drilling and completion activities. Hydraulic fracturing is a method of increasing well production by injecting fluid under high pressure down a well, which causes the surrounding rock to crack or fracture. The fluid typically consists of water, sand, chemicals and other additives and flows into the cracks where the sand remains to keep the cracks open and enable natural gas or liquids to be recovered. Fracturing fluids flow back to the surface through the wellbore and are stored for reuse or future disposal in accordance with regional regulations, which may include injection into underground wells. The design of the well bores protects groundwater aquifers from the fracturing process.

Hydraulic fracturing has been in use for some time in the oil and gas industry; however, the proliferation of fracturing in recent years to access hydrocarbons in unconventional reservoirs, such as shale formations, has given rise to public concerns about the environmental impacts of this technology. Public concern over the environmental impacts of the hydraulic fracturing process has focused on a number of issues, including water aquifer contamination; other qualitative and quantitative effects on water resources as large quantities of water are used and injected fluids either remain underground or flow back to the surface to be collected, treated and disposed; and the potential for fracturing activities to induce seismic events. Regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. Federal, provincial, territorial and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production. Public perception of environmental risks associated with hydraulic fracturing can further increase pressure to adopt new laws, regulation or permitting requirements, or lead to regulatory delays, legal proceedings and/or reputational impacts. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs and third party or governmental claims. They could also increase our costs of compliance and doing business as well as delay the development of hydrocarbon (natural gas and oil) resources from shale formations, which may not be commercial without the use of hydraulic fracturing.

If legal restrictions are adopted in jurisdictions in which the Company is currently conducting or in the future plans to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. In addition, if hydraulic fracturing becomes more regulated, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from our reserves. It is anticipated that federal, provincial and territorial regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While the Company is unable to predict the impact of any potential regulations upon our business and affairs, the implementation of new regulations with respect to water usage or hydraulic fracturing generally could increase our costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact our prospects, any of which may have a material adverse effect on our business, financial condition and results of operations.

In British Columbia, public disclosure of hydraulic fracturing fluid ingredients became mandatory as of January 1, 2012, and the provincial government established an online registry providing public access to information on fractured well locations and hydraulic fracturing fluid ingredients. In December 2012, the Alberta Energy Resources Conservation Board (now the AER) updated provincial data filing requirements used in hydraulic fracturing operations to increase public disclosure of hydraulic fracturing fluid ingredients, requiring licensees to submit fracturing fluid composition and fracturing water source data on a well-to-well basis within 30 days from conclusion of an operation.

Additionally, the Canadian federal government and certain Canadian provincial governments continue to review certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. However, certain environmental and other groups have suggested that additional federal, provincial, territorial and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources.

Further, certain governments in jurisdictions where we do not currently operate have considered or implemented moratoriums on hydraulic fracturing pending further study, and some governments have adopted, and others have considered adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs or third party or governmental claims, and could increase our cost of compliance and doing business as well as reduce the amount of natural gas and oil that we are ultimately able to produce from our reserves.

Although Company cannot predict with any degree of certainty the total impact of potential future regulations upon our business and affairs, it is possible that we could face increased operating costs or curtailment of production in order to comply with legislation governing emissions and hydraulic fracturing.

Seismicity

Seismicity events have been recorded as occurring at the same time that the Company has been conducting hydraulic fracturing and related operations. Although the size of these events is considered light, they raise stakeholder and regulatory concerns. In addition, if monitoring seismicity becomes more regulated, our fracturing activities could become subject to additional permitting requirements and result in delays as well as potential increases in costs. Restrictions on hydraulic fracturing due to a perceived correlation to seismicity could also reduce the amount of oil and natural gas that Prairie Provident is ultimately able to produce from its reserves in the affected areas.

Greenhouse Gas Emissions

The Company is subject to various GHG emissions-related legislation and monitors GHG emissions-related legislative developments in all jurisdictions in which we operate. Potential new or additional GHG legislation and associated compliance costs, in particular in association with the adoption of the Paris Agreement under the UNFCCC, may have a material impact on the Company.

In particular, key unresolved issues in relation to Canadian federal and provincial GHG regulatory requirements include the form of regulation, an appropriate common facility emissions level, availability and duration of compliance mechanisms and resolution of federal/provincial harmonization agreements. The Government of Alberta's Climate Leadership Plan includes measures to reduce methane emissions, implements an emissions limit for oil sands, introduces a broad-based carbon price (with phase-in for the upstream industry), and modifies the existing regulatory system for large emitting facilities (*see Industry Conditions – Climate Change Regulation*).

Current GHG emissions legislation does not result in material compliance costs, but compliance costs may increase in the future and may impact our operations and financial results. 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 of such matters on our operations and financial condition at this time.

Environmental and Decommissioning Liabilities

Despite our implementation of health, safety and environmental standards, there is a risk that accidents or regulatory non-compliance can occur, the outcomes of which, including remedial work or regulatory intervention, cannot be foreseen or planned for. The Company expects to incur site restoration costs over a prolonged period as existing fields are depleted. The process of estimating decommissioning liabilities is complex and involves significant uncertainties concerning the timing of the decommissioning activity; legislative changes; technological advancement; regulatory, environmental and political changes; and the appropriate discount rate used in estimating the liability. Any change to these assumptions could result in a change to the decommissioning liabilities to which we are subject. In addition, particularly with respect to operations for which the Company is not the operator and may not determine cost estimates or the timing of decommissioning, cost overruns are possible. Moreover, the Company is often jointly and severally liable for the decommissioning costs associated with our various operations and could, therefore, be required to pay more than its net share.

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. Separately, any changes to the values used to calculate each industry participant's share of the total decommissioning liabilities may also result in increases to the security that must be posted.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

In March 2001, a predecessor of PPR Canada acquired interests in certain heavy oil assets in the Eyehill Creek area of Alberta from certain predecessors of Encana Corporation. In 2003, IFP Technologies (Canada) Inc. ("**IFP**") commenced an action in the Court of Queen's Bench of Alberta against Encana Corporation and certain of its predecessors and affiliates and against certain predecessors of PPR Canada, claiming, among other things, damages in the amount of $45.6 million or, in the alternative, for an accounting of 20% of the revenues received by PPR Canada's predecessors from the acquired properties. Trial of the action and oral argument was completed in the first half of 2011. At the outset of the trial, IFP amended its claim to increase the damages sought to $56.7 million, plus interest and costs. The Court of Queen's Bench of Alberta issued reasons for judgment in August 2014 and dismissed IFP's claim in its entirety. IFP subsequently appealed the trial decision to the Court of Appeal of Alberta, challenging the lower court's findings on liability and its provisional assessment of damages. The appeal was heard in October and November 2015 and a judgment is pending. Although we cannot predict the final outcome of this case, we continue to believe that IFP's allegations are without merit, and in any event are largely covered by an indemnity between the predecessors of Encana Corporation and the predecessors of PPR Canada.

The Company is and was not otherwise a party to, and its property is and was not the subject of, any legal proceedings during the 2016 or current financial year, and the Company does not know of any such legal proceeding to be contemplated, that involves a claim for damages (exclusive of interest and costs) in an amount greater than 10% of the Company's current assets, or in respect of which an adverse determination would have a material effect on the Company.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed in this AIF, no director, executive officer, or person or company that beneficially owns or controls or directs, directly or indirectly, more than 10% of the Common Shares, nor any associate or affiliate of the foregoing, has any material interest, direct or indirect, in any transaction within the three most recently completed financial years of the Company or during the current financial year, that has materially affected or that would materially affect the Company.

TRANSFER AGENT AND REGISTRAR

Alliance Trust Company, Calgary, Alberta, is the appointed transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

Neither Prairie Provident nor any of its subsidiaries is a party to any contract entered into outside of the ordinary course of business that is material to the Company.

INTERESTS OF EXPERTS

No person or company whose profession or business gives the authority to a report, valuation, statement or opinion prepared or certified by it, which is described, included or referred to in a filing made by Prairie Provident under NI 51-102 during, or relating to, its most recently completed financial year, other than Ernst & Young LLP, the Company's independent auditors, Sproule, the Company's independent qualified reserves evaluator under NI 51-101 and Bennett Jones LLP, legal counsel to the Company.

The designated professionals of each of Sproule and Bennett Jones LLP, respectively, in each case as a group, at the time of preparing their respective reports and opinions, held less than 1% of any class of outstanding securities of Prairie Provident or its associates or affiliates, and thereafter none received or is to receive any registered or beneficial interest, direct or indirect, in any securities or other property of Prairie Provident or any of its associates or affiliates.

Ernst & Young LLP has advised they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information on Prairie Provident may be found on SEDAR at www.sedar.com, including financial information provided in the Company's annual financial statements and management's discussion and analysis for the year ended December 31, 2016, copies of are filed under Prairie Provident's company profile on SEDAR at www.sedar.com. In addition, information regarding remuneration and compensation of the Company's directors and officers, principal shareholders and securities authorized for issuance under equity compensation plans, will be contained in the Company's information circular for the meeting of Prairie Provident shareholders scheduled to be held on May 18, 2017, a copy of which will be filed under Prairie Provident's company profile on SEDAR at www.sedar.com.

SCHEDULE A

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR
(FORM 51-101F2)

(attached)

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of Prairie Provident Resources Inc. (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:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	December 31, 2016	Canada				
Total			**Nil**	**224,091**	**Nil**	**224,091**

6. In our opinion, the reserves data 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 Prairie Provident Resources Inc. (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
January 20, 2017

Original Signed by Douglas O. McNichol, P.Eng.

Douglas O. McNichol, 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, Geosciences

Original Signed by Scott W. Pennell, P.Eng.

Scott W. Pennell, P.Eng.
Senior Vice President, Engineering and Director

SCHEDULE B

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

(FORM 51-101F3)

(attached)

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

Management of Prairie Provident Resources Inc. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

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

The board of directors of the Company has:

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

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

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

The board of directors of the Company has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

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

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

(c) the content and filing of this report.

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

DATE: March 30, 2017.

(s) "*Tim Granger*"
Tim Granger
President and Chief Executive Officer

(s) "*Robert (Bob) Guy*"
Robert (Bob) Guy
Vice President, Operations

(s) *"Patrick McDonald"*
Patrick McDonald
Director

(s) "*Rob Wonnacott*"
Rob Wonnacott
Director

SCHEDULE C

AUDIT COMMITTEE CHARTER

(attached)

PRAIRIE PROVIDENT RESOURCES INC.

AUDIT COMMITTEE CHARTER

This Charter of the Audit Committee (the "Committee") of the board of directors (the "Board") of Prairie Provident Resources Inc. (the "Corporation") is adopted by the Board as of September 13, 2016.

A. Purpose

The Board has established the Committee for the principal purpose of assisting the Board in fulfilling its oversight responsibilities regarding (i) the integrity of the Corporation's financial statements and related accounting, financial reporting and audit processes, (ii) internal accounting and financial control systems and procedures, and disclosure controls and procedures, (iii) the qualification and performance of the Corporation's independent auditors ("Auditor"), and (iv) the Corporation's risk management strategies, and compliance by the Corporation with applicable legal requirements relating thereto.

While the Committee has the responsibilities set forth in this Charter, the role of the Committee is one of oversight and counsel. It is not the duty of the Committee to assure the Corporation's compliance with legal or regulatory requirements or corporate policies, or to assume the responsibilities of management of the Corporation ("Management"). In particular, the Committee is not responsible for planning or conducting financial audits or determining that the Corporation's financial statements are complete and accurate and in accordance with International Financial Reporting Standards ("IFRS"), or for planning or conducting audits. These matters are the responsibility of Management and the Auditor.

The Committee is authorized to conduct or authorize investigations into any matter that is within the scope of the powers and responsibilities delegated to the Committee, with full and unrestricted access to all books, records, facilities and personnel of the Corporation and its subsidiaries and (without limiting Part D of this Charter) the authority to engage and instruct independent counsel and such accounting and other advisors as it determines necessary or appropriate to perform its responsibilities.

B. Composition

The Committee shall consist of at least three (3) members of the Board, all of whom shall be independent under applicable securities laws pertaining to audit committees. All Committee members must also be financially literate, as determined by the Board in its business judgment, and satisfy all other requirements of applicable corporate and securities laws and stock exchange requirements regarding audit committee membership. Determinations as to whether the appointment of any particular director to the Committee meets applicable qualification criteria shall be made by the Board.

The Board shall annually appoint the members of the Committee and designate one such member to serve as Chair of the Committee, and in connection therewith review and confirm their independence and qualification.

C. Responsibilities

In furtherance of its purpose the Committee shall have the following responsibilities, and in addition to the activities specifically described in this Charter may conduct such activities incidental thereto that the Committee determines to be appropriate or as may otherwise be delegated to it from time to time by the Board:

Financial Reporting and Disclosure

- review, with Management and the Auditor, the Corporation's compliance with applicable legal and regulatory requirements regarding financial reporting and disclosure;

- review, with Management and the Auditor, significant accounting and financial reporting practices of the Corporation and related disclosure issues, including with respect to complex or unusual transactions, judgment areas such as reserves or estimates, and significant changes to accounting principles or policies, with a view to obtaining reasonable assurance as to the appropriateness of the Corporation's accounting and financial reporting practices and the fair presentation of the Corporation's financial statements in accordance with IFRS;

- review, with Management and the Auditor, their views on the appropriateness and quality (versus bare acceptability) of the Corporation's accounting principles and the degree of aggressiveness or conservatism of its accounting principles and underlying estimates;

- review, with Management and the Auditor, the identification of, accounting for and disclosure of transactions, arrangements and/or relationships with related parties;

- review new or proposed developments in accounting and financial reporting standards, or related legal or regulatory requirements, that could reasonably be expected to affect the Corporation;

- review, with Management and the Auditor, actual or anticipated litigation, contingencies or other events that could reasonably be expected to materially affect the Corporation's financial statements, and their disclosure in the financial statements;

- review, with Management and the Auditor, any "off-balance sheet" transactions or arrangements with unconsolidated entities or other persons, or that may have a material effect on the Corporation's financial statements;

- satisfy itself that adequate procedures are in place for review of the Corporation's external disclosure of financial information extracted or derived from the Corporation's financial statements, and periodically assess the adequacy of those procedures;

- review, with the Chief Executive Officer and Chief Financial Officer of the Corporation, the procedures undertaken in connection with any required certifications provided by such officers in respect of the annual or interim financial statements of the Corporation and any related management's discussion and analysis ("MD&A") or similar disclosure documents;

- review the annual and interim financial statements and any related MD&A with Management and the Auditor prior to the filing of such documents with applicable regulatory authorities or their public dissemination, and make recommendations to the Board regarding the approval of such documents;

- review earnings news releases (paying particular attention to any non-IFRS information contained therein) and any financial information or earnings guidance provided to analysts or rating agencies;

Internal Controls

- at least annually, review with Management and the Auditor the adequacy and effectiveness of the Company's accounting and financial control systems and procedures, and elicit recommendations for improvement;

- review, with Management, the Auditor and any third party engaged to provide advice on the subject, the design, evaluation, effectiveness and integrity of the Corporation's internal controls over financial reporting and disclosure controls and procedures;

- review any conclusions or analyses of Management, the Auditor and any third party engaged to provide advice on the subject, whether in connection with a certification process in respect of the annual or interim financial statements of the Corporation or otherwise, regarding the effectiveness of the Corporation's internal controls over financial reporting or disclosure controls and procedures, and any material weakness or deficiency relating to the design or operation of internal controls, and Management's response to any identified weakness or deficiency;

- obtain reasonable assurance from Management as to the payment by the Corporation to appropriate governmental authorities of all amounts required by applicable laws, including withholding taxes;

- review and oversee the investigation of any allegation of fraud, illegality or other impropriety against or otherwise involving Management or other personnel who have a role in the Corporation's internal controls, or relating in any way to the Corporation's financial position, accounting practices, internal controls, financial reporting or external disclosure;

- establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters;

- as applicable, review and approve the internal audit function (if any) for the Corporation, including with respect to scope, authority and internal reporting channels, and any annual audit plan and related budget and staffing requirements, and periodically meet with the personnel responsible for the internal audit function (if any) separately from Management;

- review any correspondence with governmental or regulatory authorities, any internal complaints and any published third party reports concerning the Corporation's financial position, accounting practices, internal controls, financial reporting or public disclosure;

Independent Auditors

- subject to requisite shareholder approvals, review and determine appointment or termination of the Auditor;

- review the independence, professional qualification and performance of the Auditor;

- oversee and approve (including by way of pre-approval with respect to non-audit services) all audit or non-audit engagements of the Auditor by the Corporation or any subsidiary, and approve the terms of engagement (including compensation);

- require that the Auditor report directly to the Committee;

- determine whether to pre-approve the provision of non-audit services by the Auditor to the Corporation or any subsidiary, and establish the scope and limits of any such pre-approval, with the Chair of the Committee having the delegated authority to grant such pre-approval on behalf of the Committee;

- in connection with any non-audit services to be provided by the Auditor, consider whether the provision of such services is compatible with the Auditor's independence;

- consider and resolve any disagreements or unresolved issues between Management and the Auditor;

- establish hiring policies regarding partners, employees and former partners and employees of the Corporation's current and former Auditors;

- review, with Management and the Auditor, the annual audit and quarterly review plans for the current year, including the scope thereof and procedures to be used;

- at the conclusion of each annual audit, review the audit directly with the Auditor and inquire into any problems or difficulties encountered, comments or recommendations of the Auditor, and Management responses;

- report the results of the annual audit to the Board;

- at least annually, obtain and review a report from the Auditor regarding: (i) its relationship(s) with the Corporation; (ii) its internal quality-control procedures; (iii) any material issues raised by its most recent internal quality-control review (or peer review), or by any inquiry or investigation by governmental or professional authorities, within the preceding 5 years, respecting one or more independent audits carried out by the Auditor, and any steps taken to deal with any such issues;

- review all material written communications between the Auditor and the Corporation, including any post-audit or management letter containing the recommendations of the Auditor, Management's response, and subsequent follow up on any identified weakness;

- at least once per fiscal quarter meet with responsible Management and the Auditor, together and also separately, to discuss and obtain feedback with respect to the annual audit or interim review process generally, significant accounting policies, alternatives discussed with Management, any preferences of the Auditor as between available alternatives, any restrictions or limitations imposed by Management or otherwise experienced by the Auditor, Management's response to any proposed adjustments identified by the Auditor, any disagreements or unresolved issues, the Auditor's evaluation of the Corporation's financial and accounting personnel, issues and concerns generally, and any other matters raised by Management, the Auditor or any Committee member;

- obtain reasonable assurance as to compliance by the Auditor with any applicable legal or professional requirements regarding partner rotation;

Risk Management

- review, with Management and the Auditor, the Corporation's assessment of its major financial risk exposures and the steps taken by Management to monitor and manage such exposures;

- review the Corporation's risk management policies and procedures concerning its principal business risks, and discuss with Management the Corporation's significant risk exposures and steps taken to monitor and mitigate such exposures;

- review the Corporation's commodity price, financial and credit risk management activities, including oil and natural gas, foreign currency and interest rate hedging activities and the use of derivative instruments;

- review the Corporation's insurance program;

- review, through discussions with Management, the Auditor and appropriate advisors, the Corporation's compliance with applicable legal or regulatory requirements and internal policies and procedures;

- review any completed or proposed related party transactions involving the Corporation or any subsidiary, including with respect to actual and potential conflicts of interest and appropriate approval processes;

Other

- maintain free and open communication among and between the Committee, the Board, the Auditor and Management;

- regularly review with Management any issues that arise with respect to the quality or integrity of the Corporation's financial statements, compliance with legal or regulatory requirements, and performance and independence of the Auditor;

- review reports and analyses prepared by the Auditor and Management with respect to any matters contemplated by this Charter;

- report to the Board on Committee activities (including review of any issues that arise with respect to the quality or integrity of the Corporation's financial statements, compliance with legal or regulatory requirements or the performance and independence of the Auditor) and make recommendations to the Board regarding any of the matters described in this Charter;

- develop and recommend to the Board such corporate policies as the Committee may from time to time determine to be appropriate in furtherance of its responsibilities;

- facilitate direct communication to the Committee, through the Chair of the Committee, by the Auditor and the internal auditor (if any);

- conduct an annual evaluation of the Committee's performance of its responsibilities under this Charter, and report to the Board on such evaluation and its results; and

- periodically review (at least annually) this Charter and any approved position description for the Chair of the Committee, including in light of any changes in law or updated regulatory guidance, and recommend to the Board such revisions (if any) as the Committee may determine to be appropriate.

Notwithstanding the responsibilities described herein, nothing in this Charter is intended to create, or shall be construed as creating, any personal duty or liability on the part of any Committee member or other director of the Corporation, beyond those duties and liabilities specifically provided for under applicable law.

D. Administrative Matters

- Meetings. The Committee shall meet on a regularly-scheduled basis at least four (4) times per year, and on such other occasions as the members of the Committee may from time to time determine or as the Board Chair or Chief Executive Officer of the Corporation may request. Unless otherwise specified in the articles or by-laws of the Corporation or this Charter, the time and place for Committee meetings, and the procedure for calling and holding such meetings, shall be determined by the Committee.

- Quorum. A majority of Committee members, present in person, or participating by electronic means, telephone or other communication facilities that permit all persons participating in the meeting to hear each other, shall constitute a quorum at any meeting of the Committee. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains.

- Change of members. The Board may at any time and from time to time remove or replace any member of the Committee, and may fill any vacancy on the Committee.

- Term of appointment. Each Committee member shall hold office as such until the close of the next annual meeting of shareholders of the Corporation following the date of his or her appointment (or re-appointment, as applicable), or until he or she resigns, is replaced or for any reason ceases to be a director, whichever first occurs.

- Attendance by others. The Committee or the Chair may, in its discretion, invite such other directors, officers and employees of the Corporation, the Auditor, outside legal counsel and other advisors as it sees fit to attend at all or any portion of any Committee meeting. A director who attends a Committee meeting but is not a member of the Committee shall not be entitled to vote on any matter before the Committee.

- Chair. The Chair of the Committee shall preside at all Committee meetings (including in camera sessions); provided that for any meeting in respect of which the Chair is absent (or there is a vacancy in the position of Chair), the other Committee members may choose one of their number to act as Chair for that meeting. The Chair of the Committee shall approve the agenda for Committee meetings in consultation with the Board Chair, appropriate executive officers of the Corporation and, as considered appropriate by the Committee Chair, other directors. Any Committee member may request that additional items be included on the agenda for a Committee meeting.

- Notice to independent auditors. Notice of Committee meetings shall be given to the Auditor, who shall have the right to appear before and be heard at any Committee meeting.

- Meeting on request of independent auditors. The Chair of the Committee shall, upon the request of the Auditor, call a meeting of the Committee to consider any matter that the Auditor wishes to bring forward.

- Advisers. The Committee shall have the authority to engage, at the Corporation's expense, independent legal counsel and such other advisers of its choosing as it may, in its discretion, from time to time determine to be appropriate in the performance of its responsibilities, and to determine the terms of engagement. The fees and expenses of such independent legal counsel and other advisors will be subject to the approval of the Chair of the Committee and paid by the Corporation.

- Funding. The Corporation shall provide the Committee with such funding as the Committee may require to pay the fees and expenses of any independent legal counsel or other adviser engaged by the Committee, and any ordinary administrative expenses incurred by the Committee in the performance of its responsibilities.

- Access to information and personnel. Without limiting their rights as members of the Board to receive and have access to information concerning the Corporation, the Committee shall, in the performance of its responsibilities, have the right to: (i) inspect any and all books and records of the Corporation; (ii) directly contact (through the Chair of the Committee) and meet with any officer, employee or consultant of the Corporation or any of its subsidiaries, or the Auditor; and (iii) discuss with any such officer, employee or consultant, or the Auditor, the information contained in such books and records and any other information or matter that the Committee determines to be appropriate.

- In camera sessions. Unless the Committee determines it to be impracticable in respect of any particular meeting, the Committee members shall hold an in camera session without Management at each regular Committee meeting.

- Minutes. Minutes shall be kept of all Committee meetings.

- Delegation. The Committee shall have the authority, in its discretion and as permitted by applicable law, to delegate to its Chair, any one or more of its members, or any subcommittee it may choose to form, its responsibility for, and authority with respect to, any matter or matters contemplated by this Charter; provided that unless expressly authorized by the Committee such delegated authority shall not include the authority to engage independent legal counsel or other experts or advisers.