PRAIRIE PROVIDENT RESOURCES

ANNUAL INFORMATION FORM

For the year ended December 31, 2019

March 26, 2020

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. See "*Company Overview and Background*" below.

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, 2019.

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;

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

"**Arsenal 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;

"**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, Lone Pine Resources Inc. and LPR Canada prior to their reorganization on September 12, 2016 under the Arsenal Arrangement, pursuant to which they became wholly-owned subsidiaries of Prairie Provident and their shareholders received Common Shares;

"**LPR Canada**" means Lone Pine Resources Canada Ltd., an Alberta corporation that was subsequently renamed Prairie Provident Resources Canada Ltd. 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 directly holds a controlling equity interest in PPR Canada;

"**Marquee**" means Marquee Energy Ltd., an Alberta corporation acquired by Prairie Provident pursuant to the Marquee Arrangement and thereafter amalgamated with Prairie Provident Resources Canada Ltd., all effective November 21, 2018;

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

"**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 (direct and indirect through LPRI) and is the amalgamated corporation continuing from amalgamations with Arsenal on January 1, 2017 and with Marquee on November 21, 2018;

"**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.

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 or plant gate.**

Although the six-to-one conversion factor is an industry-accepted norm, it is 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. 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 properties in Alberta. Our strategy is to grow organically in combination with accretive acquisitions of conventional oil prospects that can be efficiently developed. 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 operations are primarily focused on the Michichi and Princess areas in Southern Alberta targeting the Banff, the Ellerslie and the Lithic Glauconite ("**Glauconite**") formations, and an established waterflood project at 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, we completed a business combination of Lone Pine and Arsenal by plan of arrangement under section 193 of the ABCA (the "**Arsenal Arrangement**"), under which: (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 Arsenal Arrangement, and until September 12, 2016 did not carry on business other than in connection with the Arsenal Arrangement.

Our business today is conducted primarily through PPR Canada, which owns and operates substantially all of our oil and gas assets and is a wholly-owned subsidiary of Prairie Provident. PPR Canada is the amalgamation successor to LPR Canada, Arsenal and Marquee which we acquired on November 21, 2018.

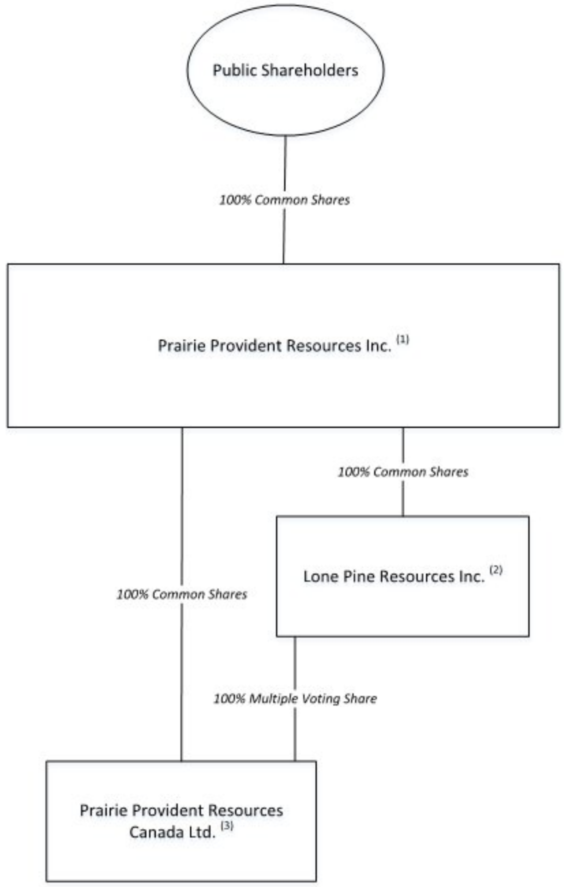
Our reserves, producing properties and principal exploration prospects are located in the provinces of Alberta and British Columbia and in the Northwest Territories.

Our head office is located at 1100, 640 - 5th Avenue S.W., Calgary, Alberta. Our 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, 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 Prairie Provident Resources Canada Ltd.

(3) Alberta corporation continuing from the amalgamation of Prairie Provident Resources Canada Ltd. and Marquee Energy Ltd. on November 21, 2018, and the amalgamation successor to (among others) Lone Pine Resources Canada Ltd. and Arsenal Energy Inc.

General Development of our Business

The Company significantly shifted its asset portfolio towards oil-focused opportunities in the latter half of 2014 when it disposed of its principal gas-weighted properties, and entered 2015 with its core operating area consisting of light oil properties at Evi in the Peace River Arch area of Northern Alberta.

During 2015, we expanded towards a second core area by acquiring mineral leases on approximately 70,000 net acres of undeveloped lands in the greater Wheatland area of southeast Alberta pursuant to a lease acquisition agreement. Our aggregate drilling expenditure commitment under the lease acquisition agreement was $45 million over a three-year period originally ending July 1, 2018, based on annual commitments of $10 million, $15 million and $20 million, respectively, for the three successive 12-month periods ending July 1, 2016, 2017 and 2018. We also entered into a farm-in and option agreement to farm-in on certain additional Wheatland area lands. An active drilling program was undertaken through December 31, 2016 pursuant to these arrangements.

In September 2016, we completed a business combination of Lone Pine and Arsenal pursuant to the Arsenal Arrangement, upon which 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. and, on January 1, 2017, amalgamated with Arsenal pursuant to the ABCA. The Arsenal Arrangement resulted in the Company becoming a public company and acquiring, through Arsenal, a new core area at Princess.

In December 2016, we completed a $4.95 million equity financing by way of prospectus offering of 5,840,000 Common Shares issued on a flow-through basis under the *Income Tax Act* (Canada), of which: (i) 5,465,000 were issued at $0.85 per share on terms requiring renunciation of "Canadian exploration expenses" to the purchasers; and (ii) 375,000 were issued for $0.80 per share on terms requiring renunciation of "Canadian development expenses" to the purchasers.

In March 2017, we added to our Evi area interests through an acquisition of strategic light oil assets in the Greater Red Earth area of northern Alberta for cash consideration of $40.9 million, subject to customary post-closing adjustments (the "**GRE Acquisition**"). The acquired assets included interests in 162 gross (97.4 net) producing oil wells, 44 gross (25.2 net) non-producing oil wells and related processing and field gathering facilities, as well as an average working interest of approximately 89% in approximately 105,000 gross (approximately 94,000 net) acres of undeveloped land. In aggregate, we acquired rights to approximately 130,000 gross (approximately 110,000 net) acres of land (both developed and undeveloped) in the GRE Acquisition.

The GRE Acquisition constituted a "significant acquisition" for Prairie Provident within the meaning of Canadian securities laws, and a business acquisition report was filed on June 5, 2017. A copy of the business acquisition report, which provides historical reserves data and financial information regarding the acquired properties, is available under Prairie Provident's company profile on SEDAR at www.sedar.com.

In connection with the GRE Acquisition, we completed an $8.3 million equity financing in March 2017 by way of bought deal prospectus offering of 5,195,000 Common Shares at a price $0.77 per share and 5,971,000 subscription receipts at a price of $0.67 per subscription receipt. The Common Shares were issued on a flow-through basis under the *Income Tax Act* (Canada) on terms requiring renunciation of "Canadian exploration expenses" to the purchasers. Each subscription receipt entitled the holder to receive, without payment of any additional consideration, on closing of the GRE Acquisition, one Common Share and one-half of one whole share purchase warrant (for an aggregate of 5,971,000 Common Shares and 2,985,500 warrants issued on conversion of all 5,971,000 subscription receipts). We subsequently issued an additional 146,170 flow-through Common Shares at the same $0.77 share price, and an additional 338,650 Common Shares and 169,325 warrants at the same $0.67 unit price, pursuant to partial exercise of the underwriters' overallotment option. Each whole warrant entitled the holder to purchase one Common Share at an exercise price of $0.87 per share (subject to adjustment in certain circumstances) until March 16, 2019. No such warrants are outstanding at the date of this AIF.

In October 2017, we completed a two-part debt financing with Prudential Capital Group ("**Prudential**") involving: (i) a three-year US$40 million senior secured revolving note facility due October 31, 2020 (the "**Revolving Facility**"), under which US$31 million principal amount of senior secured revolving notes due October 31, 2020 were issued at closing; and (ii) an issue of US$16 million principal amount of four-year senior subordinated notes due October 31, 2021 ("**Subordinated Notes**"). See "*Capital Structure and Outstanding Securities – Debt Securities*". Approximately $55.5 million (US$43 million) of proceeds was used to repay and retire the Company's previous syndicated credit facility and to cash collateralize approximately $4.8 million in outstanding letters of credit issued for ordinary business operations. All notes were issued at par by PPR Canada and are guaranteed by Prairie Provident and certain other subsidiaries. In connection with the debt financing, PPR Canada also entered into a secured $5 million letter of credit facility with a Canadian financial institution with respect to existing and future letter of credit requirements and the cash collateralization thereof. Contemporaneously with closing of the debt financing, we issued Prudential warrants to purchase up to 2,318,000 Common Shares at an original exercise price of $0.549 (subject to adjustment in certain circumstances) with a 5-year term expiring October 31, 2022. Upon completion of the Marquee Arrangement, the exercise price of these warrants was adjusted to $0.473 pursuant to their terms. See "*Capital Structure and Outstanding Securities – Convertible Securities*".

At December 31, 2017, after giving effect to additional 2017 drilling activity, amendments to the Wheatland lease acquisition agreement, and our exercise of a deferral election with respect to second-year commitments based on low commodity prices, our outstanding drilling expenditure commitments in the greater Wheatland area were approximately $23.7 million, to be satisfied over an extended final commitment period ending March 31, 2019 (subject to further extension to September 30, 2019 in certain circumstances). The capital commitment balance was further reduced in 2018 through additional drilling, which by late 2017 and into 2018 was focused on the Wayne region. Subsequent to December 31, 2018, the Company and lessor reached agreement to terminate further commitments, thereby eliminating further drilling expenditure obligations in the greater Wheatland area.

In June 2018, our Revolving Facility with Prudential was increased by US$5 million (from US$40 million to US$45 million).

In November 2018, we completed the corporate acquisition of Marquee by plan of arrangement under section 193 of the ABCA (the "**Marquee Arrangement**") under which Prairie Provident acquired all of the outstanding shares of Marquee in exchange for Common Shares, with former Marquee shareholders receiving an aggregate of 38,609,416 Common Shares based on an exchange ratio of 0.0886 Common Share for each Marquee share.

We combined the core assets of Marquee with our Wheatland properties to form one larger core area named Michichi. The Marquee Michichi assets also include a pipeline-connected 2,000 barrels of oil per day (bopd) central oil battery, and two gas plants and associated gas gathering infrastructure with 15 MMcf/d of combined processing capacity.

The Marquee Arrangement constituted a "significant acquisition" for Prairie Provident within the meaning of Canadian securities laws, and a business acquisition report was filed on February 4, 2019. A copy of the business acquisition report, which provides historical reserves data and financial information regarding Marquee, is available under Prairie Provident's issuer profile on SEDAR at www.sedar.com.

In connection with the Marquee Arrangement, we completed a $5.5 million equity financing in October 2018 by way of bought deal prospectus offering of 3,750,150 Common Shares at a price $0.46 per share and 6,810,200 subscription receipts at a price of $0.39 per subscription receipt, and concurrent private placement of an additional 2,780,000 subscription receipts at the same $0.39 price. The Common Shares were issued on a flow-through basis under the *Income Tax Act* (Canada) on terms requiring renunciation of "Canadian exploration expenses" to the purchasers. Each subscription receipt entitled the holder to receive, without payment of any additional consideration, on closing of the Marquee Arrangement, one Common Share and one-half of one whole share purchase warrant (for an aggregate of 9,590,200 Common Shares and 4,795,100 warrants issued on conversion of all 9,590,200 subscription receipts). Each whole warrant entitles the holder to purchase one Common Share at an exercise price of $0.50 per share (subject to adjustment in certain circumstances) until October 11, 2020. All such warrants remain outstanding at the date of this AIF. See "*Capital Structure and Outstanding Securities – Convertible Securities*".

On completion of the Marquee Arrangement, existing credit arrangements with Prudential in favour of PPR Canada were expanded through a US$20 million increase in the Revolving Facility (from US$45 million to US$65 million) and the issuance of an additional US$12.5 million principal amount of Subordinated Notes. See "*Capital Structure and Outstanding Securities – Debt Securities*". Additional amounts borrowed at closing were applied, in part, to finance repayment of approximately $38 million of Marquee indebtedness owed to former lenders, including a $30 million term loan from Crown Capital Partner Funding, LP with respect to which we also issued 4,400,000 Common Shares in respect of a $1,500,000 early repayment fee. Contemporaneously with closing of the expansion, we issued Prudential warrants to purchase up to 6,000,000 Common Shares at an exercise price of $0.282 (subject to adjustment in certain circumstances) with a 5-year term expiring October 31, 2023. See "*Capital Structure and Outstanding Securities – Prior Sales*".

Business Plan and Strategy

We are committed to maintaining a flexible financial position through capital discipline, operational efficiency and a robust hedging program. Our strategy focuses on building core areas with scale of liquids-rich production as well as organic and acquisition growth prospects to achieve compelling development economics. The key attributes to our business strategy include strong operational and capital efficiencies in our core areas, predictable and stable production base, and sizeable drilling inventory for organic growth.

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 also generally sold under month-to-month 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, 2019, the Company had 39 full-time employees and 32 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 add 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 estimates of the Company's proved reserves and probable reserves and related future net revenue (collectively, "**reserves data**") set forth below is based upon a report dated January 29, 2020 prepared by Sproule Associates Limited ("**Sproule**") evaluating the crude oil, natural gas and NGLs reserves of the Company as at December 31, 2019 using forecast prices and costs (the "**Sproule Report**"). The preparation date of the Sproule Report, being the most recent date to which information relating to the period ending December 31, 2019 was considered in its preparation, was January 29, 2020. 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, in accordance with NI 51-101 and, pursuant thereto, the standards contained 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 significant 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*".

Reserves Data

Reserves Data (Forecast Prices and Costs)

The following tables set forth the Company's reserves data estimates as of December 31, 2019, as evaluated by Sproule using forecast prices and costs.

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2019

FORECAST PRICES AND COSTS

	Light & Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED												
Developed Producing	6,065	5,471	403	356	19,120	17,221	324	289	329	254	10,037	8,999
Developed Non-Producing	137	128	—	—	253	215	—	—	4	3	183	167
Undeveloped	7,910	7,229	459	367	16,905	15,703	—	—	316	280	11,502	10,493
TOTAL PROVED	14,112	12,828	862	723	36,279	33,139	324	289	648	537	21,723	19,659
PROBABLE	8,003	6,976	748	634	21,554	19,720	108	96	383	318	12,744	11,230
TOTAL PROVED PLUS PROBABLE	22,115	19,803	1610	1357	57,833	52,859	432	385	1,031	855	34,467	30,889

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2019

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	22,594	129,844	135,442	127,171	117,430	22,594	129,844	135,442	127,171	117,430	15.05
Developed Non-Producing	4,804	3,874	3,219	2,740	2,378	4,804	3,874	3,219	2,740	2,378	19.31
Undeveloped	249,121	170,498	118,765	83,718	59,234	249,121	170,498	118,765	83,718	59,234	11.32
TOTAL PROVED	276,519	304,216	257,426	213,629	179,042	276,519	304,216	257,426	213,629	179,042	13.09
PROBABLE	342,818	241,269	180,312	140,492	112,901	342,818	241,269	180,312	140,492	112,901	16.06
TOTAL PROVED PLUS PROBABLE	619,337	545,485	437,739	354,121	291,943	619,337	545,485	437,739	354,121	291,943	14.17

Note:

(1) Unit values are based on net reserves.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2019

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	1,334,212	124,597	515,847	189,090	228,159	276,519	—	276,519
TOTAL PROVED PLUS PROBABLE	2,146,554	225,787	761,696	303,595	236,139	619,337	—	619,337

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, 2019

FORECAST PRICES AND COSTS

		Future Net Revenue Before Income Taxes [4] (discounted at 10%/year)	
Reserves Category	**Production Type**	**$000s**	**$/boe**
TOTAL PROVED	Light and Medium Crude Oil [1]	232,696	13.76
	Heavy Crude Oil [1]	18,431	15.74
	Conventional Natural Gas [2]	6,052	3.96
	Coal Bed Methane [3]	247	4.66
	Total Proved	257,426	
TOTAL PROVED PLUS PROBABLE	Light and Medium Crude Oil [1]	394,854	14.75
	Heavy Crude Oil [1]	34,687	16.42
	Conventional Natural Gas [2]	7,877	4.06
	Coal Bed Methane [3]	320	4.51
	Total Proved Plus Probable	437,739	

Notes:

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

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

(3) Including associated by-products but excluding solution gas.

(4) 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, 2019.

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, 2019. 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)

	Crude Oil			Natural Gas	NGLs			Inflation Rate		
Year	**WTI** [1] ($US/bbl)	**Canadian Light Sweet** [2] ($Cdn/bbl)	**Western Canada Select** [3] ($Cdn/bbl)	**AECO-C (NIT) Spot** ($Cdn/ MMBtu)	**Edmonton Propane** ($Cdn/bbl)	**Edmonton Butane** ($Cdn/bbl)	**Edmonton Condensate (Pentanes Plus)** ($Cdn/bbl)	**Operating Costs** (%/Year)	**Capital Costs** (%/Year)	**Exchange Rate** ($US/ $Cdn)
Historical										
2015	48.80	57.45	44.83	2.70	6.17	36.81	61.45	1.8%	-18.7%	0.78
2016	43.32	52.80	38.89	2.18	13.60	34.32	55.71	1.2%	-9.7%	0.76
2017	50.95	61.85	50.24	2.19	28.77	44.11	67.21	1.7%	2.4%	0.77
2018	64.77	68.49	52.34	1.53	27.00	33.65	79.31	2.4%	4.2%	0.77
2019	57.02	68.87	58.77	1.80	17.16	23.71	71.39	-0.6%	0.7%	0.75
Forecast										
2020	61.00	73.84	59.81	2.04	25.07	37.72	76.32	0.0%	0.0%	0.76
2021	65.00	78.51	63.98	2.27	31.84	43.90	80.52	1.0%	1.0%	0.77
2022	67.00	78.73	63.77	2.81	32.43	47.74	80.00	2.0%	2.0%	0.80
2023	68.34	80.30	65.04	2.89	33.26	48.69	81.68	2.0%	2.0%	0.80
2024	69.71	81.91	66.34	2.98	34.12	49.67	83.38	2.0%	2.0%	0.80
2025	71.10	83.54	67.67	3.06	34.99	50.66	85.13	2.0%	2.0%	0.80
2026	72.52	85.21	69.02	3.15	35.88	51.67	86.90	2.0%	2.0%	0.80
2027	73.97	86.92	70.40	3.24	36.78	52.71	88.72	2.0%	2.0%	0.80
2028	75.45	88.66	71.81	3.33	37.71	53.76	90.57	2.0%	2.0%	0.80
2029	76.96	90.43	73.25	3.42	38.65	54.84	92.45	2.0%	2.0%	0.80
2030	78.50	92.24	74.71	3.51	39.61	55.93	94.38	2.0%	2.0%	0.80
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%	0.80

Notes:

(1) West Texas Intermediate (WTI) at Cushing, Oklahoma, 40° API, 0.4% sulphur.

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

(3) Western Canada Select at Hardisty, Alberta, 20.5 ° API.

The weighted average historical prices realized by the Company for the year ended December 31, 2019 were $61.30 per bbl for crude oil, $1.72 per Mcf for natural gas and $30.48 per bbl for NGLs. For further information regarding the Company's production mix in 2019, 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, 2019 to the prior year's estimates, based on forecast prices and costs, by principal product type.

	Light & Medium Crude Oil			Heavy Crude Oil			Conventional Natural Gas			Coal Bed Methane			Natural Gas Liquids			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 (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBoe)	Gross Probable (MBoe)	Gross Proved Plus Probable (MBoe)	Gross Proved (MBoe)	Gross Probable (MBoe)	Gross Proved Plus Probable (MBoe)
Dec 31, 2018 [1]	15,085	7,413	22,498	446	552	998	36,331	18,925	55,256	353	116	469	714	365	1,080	22,360	11,504	33,863
Extensions	38	29	67	338	353	691	722	1,265	1,986	—	—	—	—	1	1	497	593	1,090
Infill Drilling	—	1,072	1,072	—	—	—	—	3,275	3,275	—	—	—	—	69	69	—	1,687	1,687
Improved Recovery	1,198	268	1,466	—	—	—	147	30	177	—	—	—	5	1	6	1,227	274	1,501
Technical Revisions	(336)	(869)	(1,205)	173	(150)	22	5,423	(2,149)	3,274	77	(41)	37	28	(58)	(31)	781	(1,443)	(662)
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(502)	90	(412)	(19)	(6)	(25)	(2,159)	208	(1,951)	(66)	33	(33)	(39)	5	(34)	(930)	129	(802)
Production [3]	(1,371)	—	(1,371)	(77)	—	(77)	(4,185)	—	(4,185)	(40)	—	(40)	(60)	—	(60)	(2,212)	—	(2,212)
Dec 31, 2019 [2]	14,112	8,003	22,115	862	748	1,610	36,279	21,554	57,832	324	108	432	648	383	1,031	21,723	12,744	34,466

Notes:

(1) Opening balances based on an evaluation report prepared by Sproule dated January 30, 2019 and effective as of December 31, 2018.

(2) Columns may not add due to rounding.

Year-over-year changes in the Company's estimated gross reserves from December 31, 2018 to December 31, 2019 are primarily the result of: (i) drilling and new future development reserves bookings in the Princess area (extensions); (ii) future waterflood undeveloped reserve bookings in the Evi area (improved recovery); (iii) lower operating costs in Michichi resulting in probable undeveloped drilling locations becoming economic (infill drilling) and positive technical revisions; (iv) negative technical revisions in the Wheatland and Evi areas due to removal of uneconomic undeveloped locations; (v) negative technical revisions in the Other area due to the shut-in of Chinchaga gas-weighted field; 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, 2019, 2018 and 2017 and, in the aggregate, before that time, based on forecast prices and costs.

Proved Undeveloped Reserves

	Light & Medium Crude Oil (Mbbl)		Heavy Crude 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**
2017	1,435	4,074	—	—	1,931	5,840	46	125	1,803	5,172
2018	4,827	7,803	124	124	12,979	15,953	320	374	7,434	10,960
2019	—	7,910	328	459	722	16,905	—	316	448	11,502

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**
2017	1,433	2,556	—	197	1,789	5,394	38	92	1,769	3,744
2018	3,064	5,005	235	445	9,470	13,355	212	275	5,090	7,951
2019	1,072	5,948	338	607	4,540	16,391	69	297	2,236	9,584

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 96% of the Company's estimated proved plus probable undeveloped reserves are located in the Evi, Princess and Michichi core areas. The Company currently plans to pursue the development of its proven and probable undeveloped reserves over the next four years through ordinary course capital expenditures. The development of certain probable undeveloped reserves is scheduled to occur after the end of year two to accommodate the Company's development program, which needs to be spread out over several years to optimize capital allocation and facility utilization. The Company may choose to delay development depending on a number of circumstances, including the existence of higher priority expenditures and prevailing commodity prices and cash flow. The Company has planned a program for the development of a portion of the undeveloped reserves in 2020, focusing on the Princess and Michichi drilling program.

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, decommissioning and reclamation costs associated with active assets. Active assets are fields that are in daily operation, including producing wells, suspended wells, service wells, gathering systems, facilities, and surface land development within the active fields. The reserve estimates do not include abandonment and reclamation costs associated with assets outside the active fields. Approximately $236.0 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, 2019, the Company had 1,566 gross (1,255 net) wells for which it expects to eventually incur abandonment costs, and 2,578 gross (2,030 net) wells for which it expects to eventually incur reclamation costs.

As at December 31, 2019, the Company's estimated future abandonment and reclamation obligations in respect of all of its properties (including those with no attributed reserves) was approximately $266.4 million (inflated and undiscounted), of which $20.0 million is estimated to be incurred over the next five years primarily for regulatory compliance. This was reflected in the Company's audited annual financial statements for the year ended December 31, 2019 as a decommissioning liabilities obligation of $167.8 million (discounted at risk-free rates), as more particularly described in the notes thereto and related management's discussion and analysis.

Actual expenditures on abandonment and reclamation activities for the year ended December 31, 2019 totaled $3.8 million. The Company has successfully achieved cost savings through economy of scale by managing its decommissioning activities on an area or project basis. As such, the Company may elect to spend more than the regulatory requirements to capture the economic benefits.

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, 2019, on both an undiscounted basis and based on a 10% discount rate:

Abandonment and Reclamation Costs ($millions)	**Undiscounted**	**Discounted at 10%**	**Discounted at risk-free rates**
Total at December 31, 2019	266.4	40.8	167.8

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**
2020	46,717	64,126
2021	73,373	104,684
2022	32,040	68,220
2023	36,904	66,452
2024	—	—
Thereafter	56	113
Total (undiscounted)	189,090	303,595
Total (discounted at 10%)	159,991	253,418

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 Revolving Facility (defined herein) 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, 2019 and were capable of producing but not then producing at such time, approximately 70% of such reserves were attributed to oil and natural gas properties temporarily shut-in due to depressed prices, and approximately 30% related to pending recompletions within existing wellbores.

Evi Area (Peace River Arch – Northern Alberta)

The Evi area is located in the Peace River Arch area of northern Alberta, which produces primarily light oil from the Devonian Slave Point, Gilwood and Granite Wash formations. As of December 31, 2019, we had an average working interest of approximately 81% in 100,588 gross (81,862 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 began injecting into seven additional horizontal wells in 2018. There are currently twenty-seven injection wells in operation. During the three months and year ended December 31, 2019, our Evi properties produced average sales volumes of approximately 1,668 boe per day (98% light oil and NGLs) and 1,837 boe per day (97% light oil and NGLs). 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.

Michichi Area (Southeastern Alberta)

The Michichi area is located east of Calgary in Southeastern Alberta. As of December 31, 2019, we have an average working interest of approximately 84% in 252,518 gross (211,401 net) acres. This large land position offers an organic growth platform of medium grade oil and associated natural gas opportunities from both the Lower Cretaceous Mannville formations and the Mississippian Banff formations. During the three months and year ended December 31, 2019, our average sales volumes in the Michichi area were approximately 2,243 boe per day (43% light/medium oil and NGLs) and 2,496 boe per day (45% light/medium oil and NGLs), respectively. The Company believes that it can systematically continue to increase the area production with continued development of identified locations from these oil plays.

Princess Area (Southeastern Alberta)

Our Princess properties are located in Southern Alberta, approximately 55 miles northwest of Medicine Hat. As at December 31, 2019, we have an average working interest of approximately 98% in our Princess properties comprising 36,185 gross (35,529 net) acres. The primary zones of interest are the Glauconite and Detrital formations. During 2019, we drilled, multi-stage fracture stimulated and tied in 2 gross (2 net) Glauconitic development wells and drilled and abandoned 1 gross (1 net) Glauconitic exploratory stratigraphic test well. During the three months and year ended December 31, 2019, our Princess properties produced average sales volumes of approximately, 1,361 boe per day (67% medium oil and NGLs) and 1,257 boe per day (approximately 68% medium oil and NGLs), respectively.

Main Undeveloped Properties (Shales)

As of December 31, 2019, 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 Northwest Territories properties.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company owned a working interest as of December 31, 2019. 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	446	376	660	552	176	120	245	180
British Columbia	—	—	—	—	—	—	13	11
Saskatchewan	—	—	13	4	—	—	12	12
Northwest Territories	—	—	—	—	—	—	1	1
Total	446	376	673	556	176	120	271	204

Note:

(1) Non-producing wells include wells capable of producing, but not producing, at December 31, 2019. 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, 2019. 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	233,505	193,800
Saskatchewan	4,125	3,944
British Columbia	4,527	3,092
Northwest Territories	53,788	52,995
West Cost (offshore)	112,310	112,310
East Coast (offshore)	19,084	343
Total	427,339	366,484

At December 31, 2019, 39,137 acres of our net undeveloped acreage will expire in 2020, 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, 2019, the Company does not have any other material work commitments related to its undeveloped acres.

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

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, 2019 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, 2019. 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 2072.

Costs Incurred

The following table summarizes property acquisition costs, exploration costs, and development costs incurred by the Company for the year ended December 31, 2019.

Expenditures	**($000s)**
Property acquisition (disposition) costs (net) – proved properties	(284)
Property acquisition (disposition) costs (net) – unproved properties (1)	1,832
Exploration Costs (2)	1,302
Development Costs (3)	7,460
Capitalized G&A	1,547
Total	11,856

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, 2019 in which the Company had an interest, on both a gross and net basis.

	Development (1)		**Exploratory (2)**	
	Gross	**Net**	**Gross**	**Net**
Oil wells	4.0	4.0	—	—
Dry holes	—	—	1.0	1.0
Total	4.0	4.0	1.0	1.0

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 or a service well.

Production Estimates

The following table sets forth the estimated 2020 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, Michichi and Princess fields.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbls/d)	Total Oil Equivalent (boe/d)
TOTAL PROVED RESERVES						
Evi	1,561	—	20	—	1	1,566
Princess	638	350	2,718	—	1	1,442
Michichi	1,103	—	5,768	98	127	2,208
Other Properties	381	98	2,613	—	37	952
Total Proved	3,684	448	11,119	98	166	6,167
TOTAL PROBABLE RESERVES						
Evi	84	—	1	—	—	85
Princess	83	86	431	—	1	242
Michichi	387	—	1,281	2	27	628
Other Properties	167	72	1,402	—	19	491
Total Probable	721	158	3,115	2	47	1,445
TOTAL PROVED PLUS PROBABLE RESERVES						
Evi	1,646	—	21	—	1	1,650
Princess	721	436	3,149	—	2	1,684
Michichi	1,490	—	7,049	100	154	2,835
Other Properties	548	170	4,015	—	56	1,443
Total Proved plus Probable	4,404	606	14,234	100	213	7,612

Our Evi, Princess and Michichi fields are the only properties that account for 20% or more of the Company's estimated 2020 production as reflected in the Sproule Report.

Production History

The following table summarizes, on a quarterly basis for the year ended December 31, 2019, 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, 2019	June 30, 2019	Sept 30, 2019	Dec 31, 2019
Average Daily Production [1]				
Light and Medium Oil (bbls/d)	3,640	4,028	3,759	3,436
Heavy Oil (bbls/d)	252	202	270	278
Conventional Natural Gas (Mcf/d)	11,438	11,570	11,968	11,049
Coal Bed Methane (Mcf/d)	130	139	125	120
NGLs (bbls/d)	142	204	169	149
Combined (boe/d)	5,962	6,386	6,214	5,725
Average Price Received [2]				
Light and Medium Oil ($/bbl)	57.95	66.48	62.23	60.03
Heavy Oil ($/bbl)	38.63	65.69	56.32	54.59
Conventional Natural Gas (Mcf/d)	2.45	1.14	1.15	2.22
Coal Bed Methane (Mcf/d)	2.01	1.65	0.71	1.72
NGLs ($/bbl)	38.65	28.60	25.53	31.00
Combined ($/boe)	42.67	47.03	43.01	43.81
Royalties Paid				
Light and Medium Oil ($/bbl)	4.77	8.24	7.95	7.08
Heavy Oil ($/bbl)	4.60	7.00	7.73	7.57
Conventional Natural Gas (Mcf/d)	0.02	(0.12)	(0.30)	(0.20)
Coal Bed Methane (Mcf/d)	0.22	0.19	0.10	0.16
NGLs ($/bbl)	8.92	6.59	10.30	9.97
Combined ($/boe)	3.36	5.42	4.85	4.49
Production (Operating) Costs [3][4]				
Light and Medium Oil ($/bbl)	25.01	21.16	19.95	22.45
Heavy Oil ($/bbl)	29.56	27.62	18.77	22.39
Conventional Natural Gas (Mcf/d)	3.37	3.05	2.84	3.32
Coal Bed Methane (Mcf/d)	1.05	1.71	1.98	1.31
NGLs ($/bbl)	19.37	18.17	19.48	23.72
Combined ($/boe)	23.47	20.36	18.92	21.62
Netback Received[5]				
Light and Medium Oil ($/bbl)	28.17	37.08	34.33	30.50
Heavy Oil ($/bbl)	4.47	31.07	29.82	24.63
Conventional Natural Gas (Mcf/d)	(0.94)	(1.79)	(1.39)	(0.90)
Coal Bed Methane (Mcf/d)	0.74	(0.25)	(1.37)	0.25
NGLs ($/bbl)	10.36	3.84	(4.25)	(2.69)
Combined ($/boe)	15.84	21.25	19.24	17.70

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, 2019.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbls/d)	Total Oil Equivalent (boe/d)
Evi	1,772	—	316	—	11	1,836
Princess	726	133	2,377	—	2	1,257
Michichi	822	—	5,537	122	103	1,868
Other Properties	394	117	3,280	6	50	1,110
Total	3,714	250	11,510	128	166	6,071

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 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 laws and regulations are a matter of public record and the Company is unable to predict what additional laws, regulations or amendments may be enacted.

Transportation Capacity

Canada's overall pipeline capacity and ability to access the United States and other international 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. In addition, major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other conditions have been satisfied. As further outlined below, although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory obstacles, litigation and economic and other socio-political factors. If the proposed projects are approved, improved pipeline capacity would help to alleviate the problems that Canada faces in accessing global markets for its oil supply.

The use of rail transportation as an alternative to pipelines has significantly increased in recent years. In particular, on November 28, 2018, the previous Government of Alberta announced that Alberta had commenced negotiations for investment in new rail capacity to address the historically high price differential between benchmark U.S. crude and Western Canadian Select heavy oil. In February 2019, the previous government finalized $3.7 billion in crude-by-rail contracts in order to expand transportation capacity. However, the new UCP Alberta Government has made plans to divest the $3.7 billion in crude-by-rail contracts.

The Canadian regulatory framework may impact the ability of producers 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

In 2012, Kinder Morgan Canada announced its intention to expand its existing Trans Mountain Pipeline from Edmonton, Alberta to Burnaby, British Columbia. The proposed expansion was approved by the NEB in May 2016, and by the Federal Government in November 2016. However, the project has been subject to significant legal and political opposition. Consequently, Kinder Morgan halted all non-critical spending on the expansion project and, on May 29, 2018, the Federal Government entered into an agreement with Kinder Morgan Cochin ULC to acquire the Trans Mountain Pipeline system. The shareholders of Kinder Morgan Cochin ULC subsequently voted to approve the transaction in August 2018. In August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Federal Government's indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. Following the Court's direction, Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal's decision. On February 22, 2019, the NEB announced that, following such reconsideration, it had determined to recommend that the government of Canada proceed with the project subject to 156 conditions and 16 non-binding recommendations. Although the project is approved by the Government of Canada, further appeals have been filed.

The TransCanada-led Keystone XL project would add 830,000 bbls/d in pipeline capacity for Canadian crude oil to flow to the American Gulf Coast market. Despite having been previously rejected by the Obama administration, President Trump announced his administration's approval of the project in March 2017. TransCanada has indicated that it expects construction of the project to commence after remaining local and state permits are issued, and for the pipeline to be in service two to three years following the commencement of construction. While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, pre-construction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. This decision has been appealed.

Enbridge's Line 3 replacement project, which contemplates the replacement of an existing pipeline between Hardisty, Alberta and Superior, Wisconsin, was approved by the NEB in April 2016 and by the Federal Government in November 2016. The pipeline is expected to increase pipeline capacity from Alberta by 370,000 bbls/d. United States regulatory approval processes are currently underway. Although the project has encountered multiple delays, the Minnesota Public Utilities Commission approved the Line 3 replacement project on June 28, 2018, granting a Certificate of Need and approving Enbridge's preferred route with minor modifications and certain conditions. On November 19, 2018, Minnesota regulators unanimously approved the Line 3 project, finding that the earlier conditions attached to the project had been met. Initially, Enbridge targeted an in service date of November 2019. On March 4, 2019, Enbridge revised this estimate, stating that the target in service date had been delayed until the second half of 2020. Such revision followed an announcement from Minnesota Governor Tim Walz that the Minnesota commerce department would petition the Minnesota Public Utility Commission to reconsider its approval of Line 3 through Minnesota.

Curtailment

On December 2, 2018 the Government of Alberta announced that, commencing January 1, 2019, it would mandate a reduction in provincial crude oil and crude bitumen production. Such announcement was implemented by an Order in

Council issued on December 3, 2018 approving Alta Reg 214/2018 (the "**Curtailment Rules**"). Under the Curtailment Rules, the Government of Alberta, on a monthly basis, directs oil producers producing more than 20,000 bbl/d to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The Curtailment Rules provide the framework for the Minister to make monthly curtailment orders from January 1, 2019 to December 31, 2020. This end date was extended from December 31, 2019 to December 31, 2020 in August 2019. The initial January 2019 limit was established at 3.56 million bbls/day. The most recent monthly production limit is 3.81 million bbls/day for December 2019 and January 2020.

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, but usually range from two to five years. Other terms and conditions to maintain a mineral lease are set out in the relevant legislation or are negotiated.

Continuing interests in petroleum and natural gas licenses 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 its initial term. The tenure only comes to an end when the holder can no longer prove its agreement is capable of producing oil or gas.

Many jurisdictions in Canada, including 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.

Certain oil and natural gas mineral interests are privately owned and rights to explore for and produce on such lands are granted by leases on such terms and conditions as may be negotiated between the landowner and the lessee.

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 generally calculated as a percentage of the value of gross production. The value of production and the royalty rates 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, also known as freehold 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 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 energy 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 the Company's current oil and gas production is from properties located in Alberta.

Modernized Royalty 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 from the Royalty Review Advisory Panel. The Modernized Framework applies to all wells spud on or after January 1, 2017, while wells spud prior to July 13, 2016 will continue to operate under the old royalty framework (the "**Old Framework**") for a period of 10 years ending December 31, 2026. After the expiry of this 10-year period, these older wells will become subject to the Modernized Framework. Owners of wells spud between July 13, 2016 and January 1, 2017 may elect to opt-in to the Modernized Framework early if certain criteria are met.

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 its vertical depth and horizontal length. 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 cost component attempts to incentivize innovation to reduce costs by allowing wells that are drilled and completed for less than the industry average cost to remain at a lower royalty rate 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, the royalty rate will be reduced to a minimum of 5% as the mature well's production declines.

In connection with the implementation of the Modernized Framework, the Government of Alberta has also announced two strategic royalty programs to encourage oil and gas producers to maximize production and explore resources in new areas: the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs will take into account the higher costs associated with developing emerging resources and enhanced recovery methods when calculating royalty rates.

1. Emerging Resources Program

The Emerging Resources Program began January 1, 2017 and is meant 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 must determine that all of the following criteria are met:

(i) Large Resource Potential: The project must target a resource with large hydrocarbon potential that will generate substantial long-term returns. Wells must be expected to produce a minimum of 5,000 bbls of oil per day at peak production.

(ii) Uncommerciality: 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.

(iii) Net Royalty Benefit to Albertans: The 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.

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

(v) Public Interest: It must be in the public interest to approve the project.

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 it declines over time. After the benefit period ends, wells in the scheme will be subject to normal royalty rates under the modernized framework.

2. Enhanced Hydrocarbon Recovery Program

The Enhanced Hydrocarbon Recovery 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 secondary recovery methods involving the injection of water or gas into a reservoir to increase hydrocarbon production. Programs must meet all of the following criteria:

(i) <u>Type of Well</u>: The well must be classified as crude oil, natural gas or NGL.
(ii) <u>Production</u>: The enhanced recovery scheme must produce more hydrocarbons from the pool than could be produced from the base recovery scheme for that pool by adopting either a secondary or tertiary method to inject substances into an oil or gas pool.
(iii) <u>Costs</u>: Costs of the enhanced recovery scheme are significantly greater than operating the base recovery scheme.
(iv) <u>Net Royalty Benefit</u>: The enhanced recovery scheme must provide a net royalty benefit to the Crown over the life of the scheme
(v) <u>Technical Approval</u>: The enhanced recovery scheme must be granted technical approval from the AER.

Eligible wells are subject to a flat 5% royalty for a prescribed benefit period. After the benefit period ends, wells in the scheme will be subject to regular royalty rates under the modernized framework.

<u>Royalty Freeze</u>

On July 18, 2019, the Alberta Government passed Bill 12, the Royalty Guarantee Act. The purpose of the Royalty Guarantee Act was to ensure long-term certainty that the current royalty structure will be maintained, providing assurances to long-term oil and gas investments in Alberta. Bill 12 amended the Mines and Minerals Act guaranteeing that for a period of at least 10 years, no major changes to the oil and gas structure will occur and when a well starts producing, it will be under the same royalty structure for that same time.

<u>Old Framework</u>

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017, as well as certain bitumen production. Subject to certain available incentives, and 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 includes 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, and 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.

Taxes on Freehold Production

Taxes are payable to the Province of Alberta in respect of oil and natural gas production obtained from lands other than Crown lands. The tax levied in respect of freehold oil and gas production in Alberta is calculated annually and varies depending on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

British Columbia

After Alberta, the remainder of the Company's 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 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 volume of oil produced in a month and whether the oil is produced from Crown land or freehold land. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" (oil produced from a pool discovered before October 31, 1975), "new oil" (oil produced from a pool discovered between October 31, 1975 and June 1, 1998), and "third-tier oil" (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.

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 based on: whether the gas is produced from Crown land or freehold land; whether the gas is classified as conservation or non-conservation gas; the select price set by the administrator (the Ministry of Natural Gas Development); and the reference price of the plant.

Natural gas by-products have a fixed royalty rate and gas reference prices do not apply to their sales values. There are three marketable natural gas by-products associated with natural gas production and the royalty rates are as follows: (i) natural gas liquids - 20%; (ii) condensate - 20%; and (iii) sulphur - 16.667%.

Conservation gas (conserved or marketed gas produced in association with an oil well) is subject to a lower royalty rate than non-conservation gas. For non-conservation gas, the royalty rate depends on the date of acquisition of the natural gas tenure rights and the spud date of the well. The rate may also be impacted by the select price of the non-conservation gas, 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.

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, determined using a sliding scale formula based on the level of production. For natural gas, the freehold production tax determined through a calculation using the reference price. The tax also 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.

Northwest Territories

Since the devolution of the authority of resource management from the Federal Government to the government of the Northwest Territories ("**NWT**") in 2014, public lands in the NWT have been managed under the *Northwest Territories Lands Act* and its related regulations. The Department of Industry, Tourism and Investment manages onshore oil and gas activities.

Within the Department of Industry, Tourism and Investment, the Office of the Oil and Gas Regulator manages public health, safety and conservation regulatory responsibilities for onshore oil and gas activities outside of federal areas and the Inuvialuit Settlement Region pursuant to the *Oil and Gas Operations Act.* The Petroleum Resources Division is responsible for resource management pursuant to the *Petroleum Resources Act.* Under federal legislation, the Canada Energy Regulator is the regulator for offshore operations (under federal legislation) and the regulator for the Inuvialuit Settlement Region for a period of 20 years after devolution (under territorial legislation).

With devolution, all relevant federal legislation became NWT legislation. NWT legislation mirrors the federal legislation and the content has not changed substantively. Royalties are now paid to the NWT government in most situations. As a consequence of devolution, most federal land was transferred to the NWT government. However, the Federal Government has retained some land such as the Norman Wells Proven Area.

Royalties are determined under the *Petroleum Lands Royalties Regulation*. Before a project reaches payout, royalties of 1% of gross revenues are payable for the first 18 months of production, increasing by 1% every 18 months to a maximum of 5%. After payout is reached, the royalty is the greater of 5% of gross revenues or 30% of net revenues.

In August 2019, Members of the Legislative Assembly in the NWT modernized its petroleum laws, updating the *Petroleum Resources Act and the Oil and Gas Operations Act*. The updates expand the powers of the Office of the Regulator of Oil and Gas Operations and the Minister allowing them to compel information from resource companies and decide when to withhold information from the public. Further, companies will now have 15 years to investigate a significant discovery. They must then either begin exploration or request an extension. An extension will lengthen the allowable amount of time without production to 25 years. The two acts received royal assent, but still need regulatory approval to come into force.

Environmental Regulation

All phases of the oil and gas business present environmental risks and are subject to environmental regulation under international conventions and national, provincial, territorial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges and emissions of various substances produced or used in association with oil and gas operations, as well as requirements for 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, the Company is subject to stringent federal, provincial, territorial and local laws relating to environmental protection, abandonment and reclamation. Compliance with these laws can affect the location or size of wells and facilities, the extent of exploration and development, and the 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, the imposition of remedial obligations, the incurrence of capital or increased operating costs relating to compliance and injunctions that limit or prohibit activities.

We have established internal guidelines to comply with environmental laws 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, health and safety laws. Although we maintain pollution insurance against the costs of clean-up operations, public liability, and physical damage, there is no guarantee that such insurance will be adequate to cover all such costs.

Federal

Federal environmental legislation may apply to various aspects of oil and gas projects. Current Federal environmental legislation includes, among other sources, the *Impact Assessment Act,* the *Canadian Environmental Protection Act, 1999* and the *Canadian Navigable Waters Act.* Additionally, projects may be subject to the *Fisheries Act*, which prohibits the deposit of deleterious substances or the carrying on of work that could result in serious harm to fish, and the *Species at Risk Act*, which protects critical habitat for species of concern and may limit the Company's development.

On February 8, 2018, the Government of Canada introduced Bill C-69: *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*. Bill C-69 received Royal Assent on June 21, 2019, and came into force August 28, 2019.

The *Impact Assessment Act* came into force in August 2019 and replaced the *Canadian Environmental Assessment Act, 2012*. It established the Impact Assessment Agency of Canada, which will lead and coordinate impact assessments for all designated projects, including those previously administered by the National Energy Board. The *Impact Assessment Act* applies to designated projects listed in the *Physical Activities Regulations* and physical activities designated by the Minister of Environment and Climate Change Canada on an *ad hoc* basis. The legislation expands the assessment considerations beyond the environment to expressly include health, economic, social and gender impacts, as well as considerations related to sustainability and Canada's climate change commitments. The *Canadian Energy Regulator Act* also came into force in August 2019, and replaced the National Energy Board with the Canada Energy Regulator and modified the regulator's role in federal impact assessments.

The specific project types include fossil-fuel fired power generating facilities over a certain MW, new in-situ oil sands extraction facilities over a certain bitumen production capacity, offshore production platforms and natural gas liquids storage facilities over a certain storage capacity. The *Impact Assessment Act* provides a time limit for report finalization being 300 days after the day on which the Agency posts notice that they are satisfied with the proponent's submissions. For designated projects, the Impact Assessment Agency of Canada may establish a longer time limit to cooperate with jurisdictional requirements or to take into account specific project circumstances. The Impact Assessment Agency of Canada may also establish a shorter time limit for any reason it considers appropriate.

Under the new *Canadian Energy Regulator Act*, the Canada Energy Regulator's jurisdiction for energy projects is largely the same as the current NEB. The Canada Energy Regulator continues to have jurisdiction over energy projects. The purpose of the *Canadian Energy Regulator Act* is, among other things, to ensure that pipelines and other projects are constructed, operated and abandoned in a way that is safe, secure and efficient.

The amendments to the *Fisheries Act* restore the previous prohibition against harmful alteration, disruption or destruction of fish habitat and the prohibition against causing the death of fish by means other than fishing. The amendments also introduce several new requirements to expand the scope of protection and role of Indigenous groups and interests. The prohibitions against the death of fish, and the harmful alteration, disruption or destruction of fish habitat may result in increased permitting requirements where the Company's operations potentially impact fish or fish habitat. The amendments came into force in August 2019.

Alberta

The *Environmental Protection and Enhancement Act* and the *Oil and Gas Conservation Act* are key pieces of environmental legislation in Alberta. Under the *Environmental Protection and Enhancement Act*, certain oil and activities involving substance release and reclamation may require approval from the AER or Alberta Environment and Parks, and certain activities may require an environmental impact assessment to be carried out. The *Oil and Gas Conservation Act* establishes a regulatory regime and scheme of approvals for the development of oil and gas resources and related facilities.

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, 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 comply with environmental limits and participate in regional monitoring. These frameworks are being created under the *Alberta Land Stewardship Act* ("**ALSA**") as legislative instruments equivalent to regulations. The first of seven of these frameworks, the Lower Athabasca Region Plan ("**LARP**"), came into effect on September 1, 2012, and has four parts: the Introduction, the Strategic Plan, the Implementation Plan, and the Regulatory Details Plan. Currently the LARP is in the Implementation Plan stage, under which Alberta is completing environmental management plans.

In addition, the South Saskatchewan Regional Plan was approved by the Government of Alberta in 2014, while other regional plans are at various stages of development.

Additionally, on December 19, 2017, Alberta released its Draft Provincial Woodland Caribou Range Plan, with the aim of recovering woodland caribou populations while protecting jobs and local economies.

The AER has also issued directives related to hydraulic fracturing operations in the areas of groundwater protection and induced seismicity. AER Directive 083 (*Hydsraulic 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 requires licensees to conduct a risk assessment if hydraulic fracturing operations will be conducted above or within 100 metres below the base of groundwater protection, 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. AER Directive 059 (*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.

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.

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 regulations in British Columbia are, for the most part, set out in the *Environmental Management Act* (British Columbia) ("**BCEMA**") and the *Oil and Gas Activities Act* (British Columbia) ("**OGAA**"). The OGAA regulates 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.

The British Columbia Oil and Gas Commission (the "**BCOGC**") is the provincial regulatory agency responsible 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 *Dormancy and Shutdown Regulation*. These regulations apply to both conventional and unconventional development. The *Dormancy and Shutdown Regulation* came into force in May 2019, and allows the BCOGC to order the decommissioning and reclamation of "dormant" wells.

The *Environmental Protection and Management Regulation* establishes British Columbia'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. 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.

British Columbia also requires mandatory public disclosure of hydraulic fracturing fluid ingredients under the *Drilling and Production Regulation* and has an online registry providing public access to information on fractured well locations and hydraulic fracturing fluid ingredients.

In November 2018, British Columbia passed Bill 51 which sets out new framework legislation for the *Environmental Assessment Act*. The changes to British Columbia's environmental assessment process are stated as enhancing public confidence, advancing reconciliation with Indigenous nations and protecting the environment while offering a clear pathway to sustainable project approvals. The new framework legislation came into force on December 16, 2019. Leading up to the legislation coming into force, there was a public consultation period for policy development and regulations relating to core elements of the framework.

The new Act creates an early engagement process and increases public participation in environmental assessments for resource projects. Bill 51 also requires the Environmental Assessment Office ("**EAO**") to seek to achieve consensus with Indigenous nations at various stages of the assessment process. Indigenous nations will also have an opportunity at two decision points to indicate whether the nation consents to a proposed EAO decision: i) whether to exempt a project from the assessment process or terminate the assessment process for a project; and ii) whether an Environmental Assessment Certificate should be issued. If consent is not secured, Bill 51 sets out a codified dispute resolution process.

Projects that fall within certain categories must submit a notification to the Environmental Assessment Office, even if its parameters are within prescribed thresholds. The Minister then determines whether the project is a reviewable project. Bill 51 provides specific considerations for the Minister when determining whether to designate a project. Once the project is designated as reviewable, the new early engagement process will begin. The early engagement process, increased public participation opportunities and the requirement to seek to achieve consensus with Indigenous nations, raise potential concerns surrounding increased timelines for assessments. The Ministry expects timelines to be shorter with the changes because of increased consultation at the start of projects, but the practical implications of this change remain to be seen.

On November 26, 2019, British Columbia passed Bill 41, draft legislation to implement the United Nations Declaration on the Rights of Indigenous Peoples ("**UNDRIP**"), becoming the first Canadian province to do so. UNDRIP consists of 46 articles that offer guidance to governments on recognizing and promoting rights of Indigenous people around the world. The most debated principles relate to obtaining the free, prior and informed consent of Indigenous communities before taking actions or approving projects affecting Indigenous land or resources. There has been debate about whether this means Indigenous groups have a veto, and it seems to now be generally accepted that they do not, but the legislation could nonetheless give litigious First Nations an opportunity to argue for a veto and tie up regulatory processes. Government fact sheets on the legislation emphasize that the Province retains authority for making decisions in the public interest and the legislation does not provide for the ability to veto decisions on resource projects.

In 2019, the British Columbia government submitted a constitutional reference to the British Columbia Court of Appeal regarding its ability to amend the *Environmental Management Act*. The amendments would introduce the concept of hazardous substance permits to regulate heavy oil and interprovincial pipelines. On May 24, 2019 the British Columbia Court of Appeal unanimously ruled that it is beyond the jurisdiction of the BC Legislature to enact the proposed amendments to the *Environmental Management Act*. The Court held that the proposed amendments were aimed at regulating interprovincial pipelines, which are under federal jurisdiction. Despite the unanimous decision, British Columbia's Attorney General appealed the decision to the Supreme Court of Canada. The appeal was dismissed by the Supreme Court of Canada on January 16, 2020.

Northwest Territories

Environmental legislation in the NWT is, for the most part, set out in the territorial *Environmental Protection Act* and *Oil and Gas Operations Act*, the federal *Northwest Territories Act* (Canada) and their associated regulations. In 2018, the NWT Government released its *Petroleum Resources Strategy*, which sets out ten goals under three pillars for developing the economic potential of the NWT's petroleum resources. The goals are identified as short-, medium, and long-term and the implementation of the strategy is to be reported on every three years (expected in 2021).

Environmental Legislation overall

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

The AER implements the Licensee Liability Rating ("**LLR**") program, a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The *Oil and Gas Conservation Act* established an Orphan Well Fund (the "**Orphan Well Fund**"), managed by the industry-funded Orphan Well Association ("**OWA**"), 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 posed by unfunded liabilities of licensees and prevent taxpayers in Alberta from incurring abandonment and reclamation ("**A&R**") 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 enforcement action by the AER.

The AER also employs liability management programs through the Large Facility Liability Management program, as described in Directive 024*: Large Facility Liability Management Program* and the Oilfield Waste Liability Program, as described in Directive 075*: Oilfield Waste Liability (OWL) Program.*

The AER also has an 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 AER Directive 013 (*Suspension Requirements for Wells*). The objective is to bring inactive wells into compliance with the requirements of Directive 013. Directive 013 was updated in October and December of 2018 to give licensees an additional option when suspending and inspecting medium-risk type 6 wells based on an AER closure plan, to better communicate the initial suspension and ongoing inspection requirements, and to update the Directive. The list of current wells subject to this program is available on the AER's Digital Data Submission system.

Redwater Decisions

On January 31, 2019, the Supreme Court of Canada released its decision in the case of *Orphan Well Association v Grant Thornton Ltd.* ("**Redwater**"). Reversing the decisions of the Alberta Court of Queen's Bench (the "**Redwater QB Decision**") and Alberta Court of Appeal, the Supreme Court of Canada held that trustees and receivers of insolvent parties cannot disclaim or renounce uneconomic oil and gas assets to the AER before commencing the sales process for an insolvent party's assets. Following this ruling, corporations that become insolvent will generally be required to apply the value of any remaining assets to satisfy the liabilities associated with their A&R obligations in priority to the claims of secured and unsecured creditors.

On June 20, 2016, as part of its response to the Redwater QB 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 implemented three important changes to the LLR program and the related regulatory regime, which were effective immediately.

The first change involves the consideration and processing of applications for licence eligibility under Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals. This change was codified in an amendment to Directive 067 in December 2017. The AER now has broad discretion to determine whether a party poses an "unreasonable risk" such that it should not be eligible to hold AER licences and companies now must provide more financial information to the AER. The AER assesses risk using financial, behavioural, and inventory factors to identify companies that may be unable to meet their financial responsibilities.

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

Finally, as a condition of transferring existing AER licences, approvals, and permits, the AER requires all transferees to demonstrate that they have a liability management rating of 2.0 or higher immediately following the transfer. The AER calculates liability management rating as a ratio of a company's deemed assets (production) to its deemed liabilities (abandonment and reclamation costs).

British Columbia

The BCOGC implements the Liability Management Rating (LMR) Program. Like Alberta LLR program, the LMR program manages public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations. Under the LMR Program, the BCOGC determines the required security deposits for permit holders under section 30 of the OGAA. Permit holders whose deemed liabilities exceed their deemed assets are 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, which may result in enforcement action by the BCOGC.

The Government of British Columbia has announced amendments to its LMR programs following the Redwater proceedings. In the spring of 2018 the Government of British Columbia passed certain amendments to the OGAA (the "**OGAA Amendments**") which replaced the orphan site reclamation fund tax currently paid by permit holders with a levy paid to the Orphan Site Reclamation Fund ("**OSRF**"). The OGAA Amendments require permit holders to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the OSRF. The OGAA Amendments permit the B.C.

Commission to impose more than one levy in a given calendar year. In May of 2019, the BCOGC introduced the *Dormancy and Shutdown Regulation*, introducing mandatory timelines for oil and gas site remediation.

Climate Change Regulation

Federal (Canada) - International Initiatives

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 annual Conference of Parties, the objective of which is to adopt and review legal instruments and strategies to implement goals to stabilize 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 and agreed to a new climate agreement (the "**Paris Agreement**"). Canada ratified the Paris Agreement in October 2016 and the Paris Agreement came into force on November 4, 2016. As of January 1, 2019, 184 of the 197 parties to the convention have ratified the Paris Agreement. The Paris Agreement's primary objective is to limit "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." Individual country targets designed to meet these levels are not legally binding.

At the 2016 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 in 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. No recent action on this initiative has been taken.

Canada has also agreed to reduce hydrofluorocarbons ("**HFCs**") through the Kigali Amendment to the Montreal Protocol. The amendment came into force on January 1, 2019 following ratification by 65 countries. Under the amendment, developed countries will incrementally reduce HFC consumption beginning with a 10% reduction in 2019, and reaching an 85% reduction by 2036. Most developing countries will freeze consumption in 2024, with a small number of developing countries with unique circumstances freezing consumption in 2028. The plan also provides financing to certain countries, to help them transition to climate-friendly alternatives. Unlike the Paris Agreement, this agreement is legally binding.

Canada is part of a global initiative called the *Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants* (the "**Coalition**"), which has over 100 members. The mandate is to address short-lived climate pollutants (*e.g.*, black carbon, methane, tropospheric ozone and HFCs) in order to protect human health and the environment and to slow the rate of climate change.

On June 28, 2019, the Canadian Government announced new support for international climate action and the phasing out of coal. While at the Ministerial Meetings on Climate Action, the Minister of Environment and Climate Change announced $223.5 million in funding to the Canadian Climate Fund for the Private Sector in the America Project and investments of up to $600K on global efforts to phase out coal power.

Federal (Canada) - Domestic Initiatives

Canada's Action on Climate Change initiative declares the Federal Government's intention to reduce GHG emissions through a sector-by-sector regulatory approach in order 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 air pollution using the 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**"). Standards have been developed for nitrogen dioxide, sulphur dioxide, fine particulate matter and ozone.

In 2016, the *Multi-sector Air Pollutants Regulations* introduced mandatory national performance standards for nitrogen oxides and sulphur dioxide emissions. These regulations apply specifically to oil and gas facilities and require ongoing emissions testing and reporting, although these obligations have a long-term implementation schedule.

On December 29, 2016, the *Ozone-depleting Substances and Halocarbon Alternatives Regulations* came into force, replacing the *Ozone-depleting Substances Regulations, 1998.* These regulations aim to control the level of production and consumption of certain ozone-depleting substances through a permitting and reporting system for HFCs, as well as a system for phasing out the importation and manufacturing of HFCs in Canada. Amendments to the regulations made in April 2018 added limitations on the importation of products containing HFCs and the destruction of HFCs, created consumption allowances for HFCs and elaborated on the restrictions regarding manufacturing HFCs.

In December 2016, the Government of Canada signed the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). A central feature of the Framework was the creation of a national carbon-pricing program. Accordingly, the Federal Government introduced draft carbon pricing legislation on January 15, 2018, which required all Canadian jurisdictions to implement a carbon-pricing scheme. Provinces and territories were however free to implement either a carbon tax or a cap-and-trade system, provided that they met the federal benchmark carbon price.

The *Greenhouse Gas Pollution Pricing Act* received royal assent on June 21, 2018 and provides a national carbon-pricing system that applies to GHG emissions from various sources. On October 23, 2018, pursuant to the *Greenhouse Gas Pollution Pricing Act*, the Federal Government made an announcement regarding the federal backstop standard for carbon pricing and how the revenues gained would be used. The federal backstop standard applies to any province or territory that fails to meet the federal benchmark, either increasing the carbon price or expanding the sources of emissions covered.

The federal backstop standard has two parts. First, there is a carbon levy on fossil fuels. This levy applies to prescribed liquid, gas, and solid fossil fuels at a rate of $10 per tonne of carbon dioxide in 2018. This will increase each year until it is capped in 2022 at a rate of $50 per tonne of carbon dioxide. Second, there is an output-based pricing system for industrial facilities which report emissions of 50,000 or more tonnes of carbon dioxide per year during any year after 2014. There is also an opt-in provision for facilities that report emissions in between 10,000 and 50,000 tones of carbon dioxide per year for any year starting in 2017.

The federal Department of Finance published draft regulations on October 23, 2018 outlining the applicability of the fuel charge and the relevant rates. The period of public consultation on the regulations closed on November 23, 2018. As Ontario, New Brunswick, Manitoba, and Saskatchewan do not have carbon pricing systems, the federal backstop standard is applicable to those provinces. In Ontario, New Brunswick, Manitoba, and Saskatchewan, the output-based pricing system began to apply in January 2019. The carbon levy began to apply to these provinces in April 2019. The program started in Nunavut and the Yukon in July 2019. The carbon levy will also apply to Alberta starting January 2020. PEI has implemented a provincial carbon levy. Therefore, the federal backstop standard will supplement this standard with the output-based pricing system to apply in January 2019. Saskatchewan and Ontario have challenged the constitutionality of the Federal Government's pricing regime and the cases will be heard at the Supreme Court in 2020.

On June 28, 2019, Environment and Climate Change Canada released the Proposed Regulatory Approach for the Clean Fuel Standard. This regulation will establish lifecycle carbon intensity requirements on certain liquid, gaseous and solid fuels that are used in transportation, industry and buildings, and establish rules relating to the trading of compliance credits. The stated purpose is to incentivize the use of low carbon fuels, energy sources and technologies. The carbon intensity requirements would become more stringent over time. Carbon intensity would be differentiated between different types of renewable fuels to reflect the associated emissions reduction potential. Regulated parties, which may include fuel producers and importers, would have some flexibility with respect to how to achieve lower carbon fuels in Canada.

Environment and Climate Change Canada has since published a Regulatory Design Paper for the Clean Fuel Standard in December 2018 and a Proposed Regulatory Approach for the Clean Fuel Standard in June 2019. These documents present additional details of the proposed regulatory design of the Clean Fuel Standard. The Canadian Government is reporting that new regulations under the Clean Fuel Standard are targeted to come into force on January 1, 2022 (for liquid fuels) and January 1, 2023 (for gaseous and solid fuel regulations). The Canadian federal government has indicated that over time, the new Clean Fuel Standard would replace the current Renewable Fuels Regulations.

On April 26, 2018, the Federal Government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector. The regulatory requirements for fugitive equipment leaks, venting from well completion and compressors came into force on January 1, 2020. The regulatory requirements for facility production venting restrictions and venting limits for pneumatic equipment come into force on January 1, 2023. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, while ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit the amount of methane that upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The Federal Government anticipates that these actions will reduce annual GHG emissions by approximately 20 megatonnes by 2030.

British Columbia has entered into an equivalency agreement with the Government of Canada, declaring that the federal methane regulations do not apply in British Columbia. Alberta is still trying to negotiate an equivalency agreement with the Government of Canada.

Alberta

The *Technology Innovation and Emissions Reduction Regulation* ("TIER") replaced the *Carbon Competitiveness Incentive Regulation*, effective January 1, 2020. The TIER system was released pursuant to the *Emissions Management and Climate Resilience Act*. The TIER system is an improved way to manage emissions from large industries such as the oil and gas industry, encouraging industrial facilities to find innovative ways to reduce emissions and invest in clean technology to stay competitive. The TIER system has been deemed equivalent to the federal carbon-pricing system for 2020, but in the absence of an equivalent economy-wide price on carbon, the federal fuel charge will apply to Alberta-based facilities outside the TIER system. The TIER system will automatically apply to industrial sources that emit greater than 100,000 tonnes of GHG emissions per year. Facilities that do not meet the emissions threshold of 100,000 tonnes of GHG emissions per year can opt-into the TIER system, thereby avoiding the federal fuel charge, if they compete against a facility regulated under the TIER system, or emit over 10,000 tonnes of GHG emissions and belong to a sector with high emissions intensity and trade exposure. Companies in the conventional oil and gas sector will be regulated under the TIER system.

Facilities subject to TIER have to reduce emissions by 10% in 2020, then by an additional 1% each year. To meet the requirements, the facilities have the option to reduce emissions, use credits from facilities meeting emission targets, or use emissions offsets from organizations not regulated by TIER, but have reduced emissions or pay into a TIER fund.

The *Carbon Tax Repeal Act*, which came into force on June 4, 2019 eliminated Alberta's carbon tax that was imposed on all carbon-based fuels. As Alberta is included as a "listed province" under the federal Greenhouse Gas Pollution Pricing Act (Canada), however, the federal backstop standard was imposed in Alberta starting January 1, 2020. Alberta joined Saskatchewan and Ontario in challenging the constitutionality of the federal carbon tax legislation. Following arguments heard in December 2019, the Alberta Court of Appeal held, by a 4-1 majority decision released on February 4, 2020, that the federal legislation was unconstitutional. The Alberta decision departs from decisions of the Ontario Court of Appeal and the Saskatchewan Court of Appeal upholding constitutionality. Currently, the federal backstop applies to all provinces who do not meet the federal threshold, which as of February 2020 includes Alberta, Manitoba, New Brunswick, Ontario, and Saskatchewan. It is not clear, however, whether it will continue to be applied in Alberta in light of the Alberta Court of Appeal ruling, or whether the case will be appealed to the Supreme Court of Canada.

In December 2017, Alberta pledged to create a $1.4 billion fund to help industry reduce GHG emissions. The fund will be divided into five categories, including $440 million earmarked for oil sands projects, $225 million available across sectors for projects that support climate change technology and $400 million in loan guarantees to support efficiency and renewable energy measures.

The now repealed *Climate Leadership Act* also created Energy Efficiency Alberta, a carbon tax funded Government of Alberta agency that works to develop and deliver programs and services promoting energy efficiency and the development of small-scale energy systems. Some recent initiatives include the Business, Non-Profit and Institutional Energy Savings Program in 2017, which offers rebates to organizations that install high-efficiency heating or lighting products, and the Residential and Commercial Solar Program, which offers rebates to organizations that install solar photovoltaic systems. In October of 2019, the Alberta Government scrapped a series of programs instituted by Energy Efficiency Alberta and the agency is no longer accepting new applications.

Finally, Alberta joined interprovincial alliances to further climate change initiatives. On May 26, 2016, Alberta's Climate Change and Emissions Management Fund and Ontario Centres of Excellence signed a memorandum of understanding ("**MOU**") to accelerate the development of clean technology initiatives. This alliance is aimed at helping both provinces reduce GHG emissions and shift to a lower-carbon economy. Alberta and Manitoba also signed a MOU in January 2016, which included a commitment to share information and develop measures relating to energy conservation, renewable energy development and GHG reduction policies. On February 16, 2012, the Government of Alberta and the Government of Canada signed a Memorandum of Understanding with the purpose of establishing a strategic framework for collaboration on research and innovation promoting responsible and sustainable development of oil sands and heavy oil. This Memorandum of Understanding was renewed on February 13, 2017, with both governments continuing the collaboration with an expanded scope to include clean energy technologies. It is unclear what actions the new Alberta Government will take with this Memorandum of Understanding going forward.

British Columbia

In May 2017, the British Columbia New Democratic Party and the British Columbia Green Party entered into a coalition to form the provincial government. The new government has started implementing its climate change policies, which differ from those of the previous government.

British Columbia's current GHG emissions reduction goals are set out in the *Climate Change Accountability Act*. The province intends to reduce its GHG emissions by 40% below 2007 levels by 2030, 60% by 2040 and 80% by 2050. Moreover, the government intends to set sector-specific reduction goals for transportation (30% reduction by 2030), industry (30% reduction by 2030), and buildings and homes (50% reduction by 2030). In October 2019, legislation was tabled amending the *Climate Change Accountability Act* to set interim emission targets on the path to the legislated 2030 emissions target. The amendments will also include separate sectoral targets, established following engagement with stakeholders, Indigenous peoples and communities throughout the province.

British Columbia has primarily attempted to reduce GHG emissions by means of a carbon tax on the purchase and use of fuels (e.g., gasoline, diesel, natural gas, heating oil, propane, and coal). On April 1, 2019, the carbon tax rose from $35 to $40 per tonne of carbon dioxide equivalent emissions. The *Climate Change Accountability Act* requires the government to report every second year on the level of emissions reductions achieved in the province. The provincial carbon tax will continue to increase by $5 per tonne of carbon dioxide equivalent per year until it reaches the federal target carbon price of $50 on April 1, 2021.

The *Greenhouse Gas Emission Reporting Regulation* requires any facility that emits 10,000 tonnes or more of carbon dioxide equivalent per year to report their emissions annually. Facilities emitting over 25,000 tonnes of carbon dioxide equivalent per year are required to have their emission reports independently verified. The associated *Greenhouse Gas Industrial Reporting and Control Act* provides the regulatory framework for reporting emissions. The *Greenhouse Gas Industrial Reporting and Control Act* sets an emissions limit for LNG of 0.16 tonnes of carbon dioxide equivalent per tonne of LNG produced. Performance standards for other sectors will likely be added in the future. Facility operators are able to meet such limits in various ways, including: (i) earning offset units via verified reductions of GHG emissions; (ii) purchasing funded units; and (iii) earning credits for each tonne of GHG emissions below the emissions limit.

The *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and the associated *Renewable and Low Carbon Fuel Requirements Regulation* require fuel suppliers to progressively decrease the average carbon intensity of their fuels with the aim of achieving a 10% reduction of 2010 levels by 2020. Fuel suppliers must ensure that they have a minimum renewable fuel content of 5% for gasoline and 4% for diesel on a provincial annual average basis.

On October 23, 2017, British Columbia appointed a Climate Solutions and Clean Growth Advisory Council to advise the government on matters, including carbon dioxide reduction policies, while maximizing job and economic opportunities and implementing the recommendations of the 2015 Climate Leadership Team. The 2015 Climate Leadership Team recommendations included measures to reduce fugitive and vented methane emissions and amending the *Clean Energy Act* to increase the target for clean energy on the integrated grid from 93% to 100% by 2025 (except where fossil fuel capacity is required for back-up or reliability).

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan ("**CleanBC**"). The government estimates that the industry, buildings and transportation initiatives in the CleanBC plan will collectively reduce the province's emissions by 18.9 Mt, or 75% of the province's 2030 climate target, with the remaining 6.1 Mt to be achieved through other initiatives currently being planned. Key initiatives under the CleanBC plan include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of oil and gas production; (v) reducing methane emissions from upstream oil and gas operations by 45%; and (vi) mandating that 10% of new cars will be zero-emissions vehicles ("**ZEVs**") by 2025, 30% will be ZEVs by 2030, and 100% will be ZEVs by 2040.

On January 16, 2019, the B.C. Commission announced a series of amendments to the Drilling and Production Regulation that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules are planned to come into effect on January 1, 2020.

Given the price on carbon in BC, the federal backstop standard does not apply to BC. It will likely not apply to BC in the near future, as the government has announced a planned annual increase of $5 per tonne of carbon dioxide until the carbon tax is $50 per tonne of carbon dioxide in 2021, a year before the federal backstop standard would require this rate of carbon tax.

On August 29, 2019, the Canadian and British Columbia Governments announced a Memorandum of Understanding to affirm the joint commitment to power British Columbia's natural gas production and liquefied natural gas sectors with its clean electricity. A new Canada-British Columbia Clean Power Planning Committee, including representatives from the provincial and federal governments and BC Hydro, will work to advance projects that increase power transmission and electrification across the province.

Northwest Territories

On May 1, 2018, the Government of the NWT released the 2030 Climate Change Strategic Framework. The goals of the framework are to transition to an economy that uses less fossil fuel, reducing greenhouse gas emissions by 30% below 2005 levels by 2030, increase understanding of climate change impacts occurring in the NWT and build resilience to a changing climate. On May 29, 2019, the Government of NWT released its 2030 NWT Climate Change Strategic Framework 2019-2023 Action Plan, the first of two five-year Action Plans guiding implementation of the 2030 Climate Change Strategic Framework. The Action Plan focuses on improving knowledge of climate change impacts, building resilience and adapting to a changing climate and aiming to support ecosystem viability, while managing the natural environment and demands on it.

In April 2018, the Government of NWT released the 2030 Energy Strategy. The objectives of the Energy Strategy are to: work together to find solution through community engagement, participating and empowerment; reduce GHG emissions from electricity generation in diesel-powered communities by an average of 25%; reduce GHG emissions from road vehicles by 10% per capita; increase the share of renewable energy used for space heating to 40%; increase residential, commercial and government building energy efficiency by 15%: and to develop the NWT's energy potential. In August 2019, the Government of NWT released its 2019 Energy Action plan report summarizing the actions and initiatives undertaken to contribute to the six strategic objectives in the 2030 Energy Strategy.

The NWT is a signatory to the Pan-Canadian Framework for Clean Growth and Climate Change. The territory released its plan for implementing carbon pricing. The carbon pricing plan introduces a carbon tax of $20 per tonne of carbon dioxide effective September 1, 2019 and increasing annually until it reaches $50 per tonne. This tax will exclude aviation fuel. In addition, the plan aims to enhance benefit programs to offset the tax, to rebate the NWT Power Corporation for tax paid on fuel necessary to produce electricity to stabilize electricity prices and to establish rebate programs for large GHG emitters to offset the impact of the tax and incentivize reductions in GHG emissions. In order to accomplish this, the Government of NWT plans to amend the *Petroleum Products Tax Act* effective July 1, 2019.

As the NWT has its own system which meets the federal standard, the federal backstop standards will not apply to the territory.

CAPITAL STRUCTURE AND OUTSTANDING SECURITIES

Share Capital

The authorized share capital of Prairie Provident consists of an unlimited number of Common Shares, of which 172,064,362 Common Shares are 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 arrangements include 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:

- incentive awards held by directors, officers and employees and outstanding under the Company's security based compensation arrangements; and
- share purchase warrants issued under financing transactions described above under "*Company Overview and Background – General Development of our Business*", as follows: (i) 4,795,100 warrants issued in our October 2018 equity financing undertaken in connection with the Marquee Arrangement, each of which is exercisable for one Common Share at an exercise price of $0.50 per share (subject to adjustment in certain circumstances) until October 11, 2020; (ii) 2,318,000 warrants issued to Prudential contemporaneously with our October 2017 debt financing, each of which is currently exercisable for one Common Share at an adjusted exercise price of $0.473 per share (subject to adjustment in certain circumstances) until October 31, 2022; (iii) 6,000,000 warrants issued to Prudential contemporaneously with the November 2018 expansion of our credit arrangements, each of which is exercisable for one Common Share at an exercise price of $0.282 per share (subject to adjustment in certain circumstances) until October 31, 2023.

Outstanding incentive awards at the date of this AIF are comprised of: (i) 6,565,992 incentive stock options held by officers, employees and directors, each exercisable for one Common Share at an exercise price of $0.05 (as to 2,633,673 options), $0.21 (as to 2,175,480 options), $0.76 (as to 1,294,130 options) and $0.96 (as to 462,709 options) per share, subject to vesting in accordance with their terms; (ii) 2,337,081 deferred share units (DSUs) held by non-executive directors, each entitling the holder to receive, on settlement following cessation of service, one Common Share or the cash equivalent thereof; and (iii) 2,933,571 restricted share units (RSUs) held by officers and employees, each entitling the holder to receive, subject to vesting in accordance with their terms, on settlement thereafter, one Common Share or the cash equivalent thereof.

Debt Securities

Outstanding debt securities are comprised of senior secured revolving notes under the US$60 million Revolving Facility due April 30, 2021 and US$28.5 million original principal amount of Subordinated Notes due October 31, 2021 issued by PPR Canada to Prudential pursuant to the debt financing transactions described above under "*Company Overview and Background – General Development of our Business*".

Secured Notes (Revolving Facility)

The Revolving Facility is a borrowing base facility that (as amended in connection with completion of the Marquee Arrangement) provides for total revolving commitments equal to the lesser of USD $60 million and the then-applicable borrowing base determined by the secured noteholders in accordance with their customary procedures and standards having regard to, among other things, the Company's proved reserves. The borrowing base is subject to a semi-annual redetermination following scheduled delivery of year-end and mid-year reserves reports on or before March 31 and September 30 for each year during the term. The next borrowing base redetermination will occur on or about March 31, 2020 based on delivery of the 2019 year-end reserves report.

The Revolving Facility is a three-year facility, and all Secured Notes issued thereunder extended the maturity date from October 31, 2020 to April 30, 2021, and removed the "term out" feature so as to keep the facility as a revolving facility for the remaining of the term. PPR Canada can make further draws under the Revolving Facility on or before April 30, 2021, subject at all times to the then-applicable commitment amount. The Secured Notes are repayable at PPR Canada's election at par plus interest and any applicable breakage costs, without reduction in the aggregate commitment under the Revolving Facility.

The Revolving Facility is ultimately denominated in United States dollars but accommodates Canadian dollar denominated advances up to the lesser of $54 million and the Canadian dollar equivalent of US$30 million. Of the Secured Notes outstanding at December 31, 2019, $40.5 million are denominated in Canadian dollars (US$30.0 million equivalent using the exchange rate at the time of borrowing).

Amounts borrowed under the Revolving Facility can be drawn in the form of USD or CAD prime advances bearing interest based on reference bank USD and CAD prime lending rates announced from time to time, or LIBOR advances (in the case of USD amounts) or CDOR advances (in the case of CAD amounts) bearing interest based on LIBOR and CDOR rates in effect from time to time, plus an applicable margin. Applicable margins per annum are as follows:

- for CDOR advances and Canadian dollar prime advances, the margins are between 350 and 500 basis points ("bps");
- for LIBOR advances and US dollar prime advances, the margins range from 325 to 475 bps; and

except that, pursuant to amendments agreed in the fourth quarter of 2019, the applicable margin for the period between December 1, 2019 and March 31, 2020 is fixed at 500 bps for all advance types. Standby fees on any undrawn borrowing capacity are between 50 and 87.5 bps per annum. The applicable margins (except as fixed for the period ending March 31, 2020) and standby fees depend on the Company's debt-to-EBITDAX ratio as of the previous quarter end.

The note purchase agreement for the Revolving Facility and related parent and subsidiary guarantees contain various covenants on the part of the Company and its subsidiaries. Included among the covenants are commitments by PPR Canada to meet certain financial tests, calculated in accordance with the note purchase agreement, with respect to:

- total leverage ratio, pursuant to which the ratio of adjusted indebtedness to EBITDAX for the four quarters most recently ended cannot exceed 3.75 to 1.0 for the fiscal quarter ending December 31, 2019, and cannot exceed 3.5 to 1.0 for subsequent periods;
- senior leverage ratio, pursuant to which the ratio of senior adjusted indebtedness to EBITDAX for the four quarters most recently ended cannot exceed 3.25 to 1.0 for the fiscal quarter ending December 31, 2019, and cannot exceed 3.0 to 1.0 for subsequent periods;
- asset coverage ratio, pursuant to which the ratio of adjusted net present value of estimated future net revenue from proved reserves (discounted at 10% per annum) to adjusted indebtedness as of the date of any reserves report cannot be less than 1.3 to 1.0; and
- current ratio, pursuant to which the ratio of consolidated current assets, plus any undrawn capacity under the Revolving Facility, to consolidated current liabilities at the end of any fiscal quarter cannot be less than 0.85 to 1.0 for the fiscal quarter ending December 31, 2019, and cannot be less than 1.0 to 1.0 for subsequent periods.

For purposes of the Revolving Facility, EBITDAX is measured as net earnings before financing charges, foreign exchange gain (loss), E&E 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 – all in accordance with the terms of the note purchase agreement and based on financial information from the most recent four consecutive fiscal quarters.

Subordinated Notes

The Subordinated Notes are four-year instruments with a scheduled maturity date of October 31, 2021. They bear interest at 15% per annum, payable quarterly in arrears on the 30th day of January, April, July and October in each year, with up to 5% per annum payable in kind at PPR Canada's election. The amount of any such in-kind payment will become additional principal owing in respect of the Subordinated Notes. The terms of the Revolving Facility require that PPR Canada make the maximum in-kind election.

The note purchase agreements for the Subordinated Notes and related parent and subsidiary guarantees contain various covenants on the part of the Company and its subsidiaries, including commitments by PPR Canada to meet the similar financial tests described above.

Escrow

To the knowledge of the directors and executive officers of the Company, other than restrictions applicable to the transfer of incentive awards, 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 Arsenal 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**
January 2019	0.240	0.190	3,020,467
February 2019	0.280	0.170	5,286,176
March 2019	0.240	0.165	2,510,388
April 2019	0.220	0.150	4,020,248
May 2019	0.175	0.100	3,108,757
June 2019	0.115	0.075	1,402,509
July 2019	0.125	0.075	2,440,492
August 2019	0.090	0.045	4,526,399
September 2019	0.090	0.055	5,270,317
October 2019	0.060	0.035	5,219,016
November 2019	0.070	0.035	6,229,504
December 2019	0.060	0.045	10,865,286
January 2020	0.055	0.040	2,832,178
February 2020	0.040	0.025	2,077,766
March 1-24, 2020	0.035	0.005	7,470,625

Prior Sales

Since January 1, 2019, Prairie Provident has granted: (i) 1,701,369 DSUs to directors in lieu of an aggregate of $135,000 in quarterly directors' fees otherwise payable in cash; (ii) 2,373,633 RSUs and 2,373,633 stock options to officers and employees pursuant to long-term incentive awards granted effective February 5, 2019 and (iii) 2,633,673 stock options and 975,435 RSUs to officers and employees pursuant to long-term incentive awards granted effective February 5, 2020.

The RSUs vest in one-third increments on each of the first and second anniversaries of their grant dates and on December 15 of the third year, with each vested RSU entitling the holder to receive one Common Share or the cash equivalent thereof. On February 5, 2019 and February 5, 2020, being the respective grant dates of the outstanding RSUs granted since the start of the last financial year, the closing prices on the TSX of the Common Shares was $0.20 and $0.04. On February 1, 2019 and February 5, 2020, the Company issued an aggregate of 95,398 and 637,913 Common Shares in partial settlement of vested RSUs granted in early 2018 and 2019, respectively.

The stock options vest in one-third increments on each of the first, second and third anniversaries of their grant date, with each vested option entitling the holder to purchase one Common Share at an exercise price of $0.21 (with respect to those granted February 5, 2019) and $0.05 per share (with respect to those granted February 5, 2020) for a five-year term expiring February 5, 2024 and February 5, 2025, respectively.

The DSUs vest immediately upon grant, with each DSU entitling the holder to receive, on settlement following cessation of service, one Common Share or the cash equivalent thereof ; provided that any Common Shares delivered in settlement of DSUs granted after June 30, 2019 must be acquired in the secondary market and cannot be new Common Shares issued from treasury. See "– Convertible Securities".

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 Arsenal 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 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 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
Terence (Tad) Flynn (1)(3)(4) Rhode Island, 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 (2)(3)(4) Alberta, Canada *Director*	Director of Finance, MILS Group (oilfield services and equipment); prior thereto, 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
William Roach (2)(3) Alberta, Canada *Director*	President and Chief Executive Officer of Cavalier Energy Inc. (oil sands company) since January 2012; Interim Chief Executive Officer of Marquee from November 2017 to November 2018, and Chairman of Marquee from December 2016 to November 2018	November 2018
Ajay Sabherwal (1)(2)(4) 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
Rob Wonnacott (1)(2)(3) 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 of the Company 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
Brad Likuski Alberta, Canada *Vice President, Operations*	Vice President, Operations of the Company since October 2018; prior thereto, Manager of Exploitation of the Company since May 2016; prior thereto, Vice President, Production at Spyglass Resources Corp. (oil and gas exploration and production) from April 2013 to April 2016	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 Audit Committee of the Board of Directors, consisting of Messrs. Sabherwal (Chair), Flynn and Wonnacott.

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

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

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

Each of the current directors was elected a director at the 2019 annual meeting of shareholders.

The term of office of each director expires at the next annual meeting of Prairie Provident's shareholders.

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 3,159,236 Common Shares, representing approximately 1.84% of the outstanding Common Shares (calculated on an undiluted basis).

Messrs. McDonald and Wonnacott were directors of, and Mr. Granger was an executive officer and director of, one or more of LPRI, LPR Canada and their affiliates at the time when Lone Pine commenced restructuring proceedings under the *Companies' Creditors Arrangement Act* (Canada) and Chapter 15 of the United States Bankruptcy Code in September 2013, and continued in such capacities through successful implementation of a comprehensive capital reorganization and financial restructuring on January 31, 2014. 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. Dr. Roach was appointed a director of Sonde Resources Corp. ("Sonde") (then named Canadian Superior Energy Inc.) in September 2009 in connection with the completion of the proceedings commenced by that company and certain of its subsidiaries under the CCAA in March 2009 and the implementation of a CCAA plan of compromise or arrangement thereunder. Sonde experienced financial distress in late 2014 and filed a voluntary assignment in bankruptcy under the Bankruptcy and Insolvency Act (Canada) on February 2, 2015. Dr. Roach and all other directors and officers of Sonde resigned immmediately prior to the bankruptcy filing. In the circumstances, Sonde did not file its interim filings for the third quarter ended September 30, 2014 as required, and cease trade orders were issued by Alberta, British Columbia, Manitoba, Ontario and Quebec securities regulators in November 2014 and December 2014, respectively. Dr. Roach was a director of Porto Energy Corp. ("Porto") from September 2010 until the resignation of all of Porto's directors on May 30, 2014 in connection with the winding down of Porto's operations. Trading in Porto's shares on the TSX Venture Exchange were subsequently suspended, and Porto became the subject of cease trade orders by Alberta, British Columbia, Manitoba and Ontario securities regulators in August 2014 for failure to make its interim filings for the quarter ended May 31, 2014. Dr. Roach was previously an outside director of KiOR, Inc. ("KiOR"), a Houston-based biofuels company, from July 2010 until his resignation in October 2014. Kior commenced proceedings under Chapter 11 of the United States Bankruptcy Code in March 2014 and completed its reorganization thereunder in June 2015.

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 auditor of the Company is Ernst & Young LLP, Chartered Professional Accountants, which has served as our auditor since 2011. Ernst & Young LLP is independent with respect to the Company in the context 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 to the Company by Ernst & Young LLP for each of the last two financial years.

	Financial year ended December 31,	
(in $000s)	**2018**	**2019**
Audit Fees (1)	240	254
Audit-Related Fees (2)	76	—
Tax Fees (3)	63	2
All Other Fees	1	1
Total Fees	380	257

Notes:

(1) Audit Fees were paid, or were payable for the audit of the Company's annual financial statements and reviews of the 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 cash flows, are highly dependent upon our success in exploiting our 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 our oil and natural gas reserves and our 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, actions taken by Saudi Arabia, other members of the Organization of Petroleum Exporting Countries (OPEC) and other major oil producing countries (including Russia), or their state influenced enterprises, to change global crude oil supply or otherwise influence prices, world economic conditions, government regulation, international trade disputes, 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. Any contraction, or deceleration of growth, in the United States, the People's Republic of China and other major oil consuming economies, whatever the cause, will adversely affect oil prices. 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 potential causes of conditions that reduce energy demand or increase market uncertainty are innumerable and cannot be predicted with certainty. The coronavirus (COVID-19) pandemic is a current and very significant such cause, with materially adverse impacts on public resources, industrial output, employment, consumer spending, international trade, transportation networks, travel, financial markets, investor confidence and governmental priorities, all on a global scale. Its adverse effect on economic, market and business conditions generally, and on oil prices specifically, is significant, and its duration is unknown.

The substantial and extended decline in the prices of crude oil, natural gas and NGLs has 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 Revolving Facility limits the amounts the Company can borrow to a borrowing base amount, determined by the secured noteholders in their discretion based on their internal criteria and valuation of our estimated reserves, and that valuation is adversely affected by low commodity prices;

- the note purchase agreements governing our Revolving Facility and the Subordinated Notes require that the Company maintain compliance with the financial ratios described above under "*Capital Structure and Outstanding Securities - Debt Securities*", which include ratios based on an EBITDAX measure that is adversely affected by low commodity prices;

- we may be unable to obtain adequate funding under our Revolving Facility if any secured noteholder is unable or unwilling to meet its commitment; and

- the operating and financial restrictions and covenants under the note purchase agreements governing our Revolving Facility and the Subordinated Notes restrict (and any future debt financing agreements will likely restrict) our 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 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 Revolving 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 our Revolving Facility is based on a borrowing base, which is subject to periodic redeterminations and will be determined by the secured noteholders in their discretion based on their internal criteria and valuation of our estimated reserves. There can be no assurance that the noteholders will maintain our borrowing base at current levels or at levels that otherwise meet the Company's liquidity and capital resource requirements.

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.

See also "*Risk Factors - Volatility of Crude Oil, Natural Gas and NGL Prices*" in this AIF.

Recent credit concerns and related turmoil in the energy sector and disruption to the broader economy have adversely impacted our business and access to capital, and we may face additional challenges if these economic and financial market conditions persist or worsen. The materially adverse impacts of the COVID-19 pandemic on public resources, industrial output, employment, consumer spending, international trade, transportation networks, travel, financial markets, investor confidence and governmental priorities are significant. 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 and other 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 Arrangements

The note purchase agreements governing our Revolving Facility and the Subordinated Notes contain, and future agreements governing replacement or other indebtedness will likely contain, restrictive covenants that impose significant operating and financial restrictions on the Company, including restrictions on our 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;
- 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; and

- engage in certain business activities.

The note purchase agreements governing our Revolving Facility and the Subordinated Notes also require that the Company maintain compliance with the financial ratios described above under "*Capital Structure and Outstanding Securities - Debt Securities*".

As a result of these covenants and restrictions the Company will be limited in the conduct of its 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 prevailing commodity prices and other events and circumstances beyond the Company's control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired.

The note purchase agreement governing our Revolving Facility also limits the amounts the Company can borrow to a borrowing base amount, determined by the secured noteholders in their discretion based on their internal criteria and valuation of our estimated reserves. 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 debt, sell assets or issue equity or more debt. 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 our credit arrangements.

A failure to comply with requirements of the note purchase agreements governing our Revolving Facility and the Subordinated Notes (or of any future debt financing agreements) 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 either note purchase agreement occurs and remains uncured, the lenders thereunder:

- in the case of the Revolving Facility, would not be required to advance any additional amounts thereunder;
- 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. In addition, there can be no assurance that the applicable provincial governments will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Company's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic. In particular, on January 29, 2016, the Government of Alberta adopted a new royalty regime that took effect on January 1, 2017. See "*Industry Conditions - Royalties*".

Stakeholder Opposition

Our planned activities may be adversely affected if there is strong community opposition to our 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 Partner Relationships

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 our 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 expect 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 our 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. 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. Any external circumstance that renders our personnel unable to work, or disrupts their ability to effectively access the workplace resources necessary to discharge their responsibilities for the Company, will also adversely affect our operations. The effect of the COVID-19 pandemic, including any adverse impact on employee health and responsible and proper measures to limit physical proximity among personnel, is such a circumstance.

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 we operate, 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 security holders. 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.

Significant Shareholder

To the Company's knowledge, Goldman Sachs Asset Management, L.P. (GSAM) exercises control or direction, directly or indirectly, over 49,433,242 Common Shares representing approximately 28.9% 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. In particular, absent a near unanimous determination by all other shareholders, the support of GSAM will 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) was previously an insider of Prairie Provident by reason of holding more than more than 10% of the Common Shares that were outstanding immediately prior to completion of the Marquee Arrangement on November 21, 2018. To the Company's knowledge, GS&Co held 14,791,376 Common Shares as at November 21, 2018, which number represents approximately 8.6% the total number of Common Shares (undiluted) outstanding at the date of this AIF. Prairie Provident does not know whether GS&Co continues to hold Common Shares.

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 Arsenal Arrangement.

GSAM and GS&Co (or clients for whom they act, as applicable) were significant shareholders of Lone Pine and, pursuant to the Arsenal Arrangement, received Common Shares in substitution for their Lone Pine shares on the same terms as were applicable to all other holders of Lone Pine shares.

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 Revolving Facility is unable or unwilling 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.

British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador and the Northwest Territories have all implemented carbon pricing mechanisms which meet or exceed the current federal benchmark carbon price of $30 per tonne. The federal backstop standard went into effect on April 1, 2019 and affects provinces and territories which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing, namely Alberta, Ontario, Manitoba, Saskatchewan and New Brunswick. Alberta was included on this list, despite its introduction of the TIER system, due to the provincial government's elimination of the Climate Leadership Regulation. As the TIER system only applies to certain classes of large industrial emitters and does not include an economy-wide price on carbon, the federal backstop will apply to sources in Alberta not governed by the TIER, including smaller industrial emitters and households. The federal benchmark carbon levy had an initial rate of $20 per tonne, increasing by $10 per tonne annually until it reaches $50 per tonne in 2022. The direct or indirect costs of compliance with these regulations, as well as other regulations relating to the pricing and reduction of GHG emissions, may have a material adverse effect on the Company’s business, financial condition, results of operations and prospects. In addition, given ongoing litigation and political opposition relating to certain of these regulations, it is not possible to predict the impact of these regulations on the Company and its operations and financial condition.

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.

British Columbia requires mandatory public disclosure of hydraulic fracturing fluid ingredients under the *Drilling and Production Regulation* and the provincial government has an online registry providing public access to information on fractured well locations and hydraulic fracturing fluid ingredients. In Alberta, the AER has issued multiple directives relating to hydraulic fracturing operations. AER Directive 083: *Hydraulic Fracturing - Subsurface Integrity* requires licensees to demonstrate that operational risks have been considered in the selection and design of wellbore construction and that licensees monitor and test such wellbores to ensure that well integrity is maintained. It also subjects licensees conducting hydraulic fracturing above or within 100 metres below the base of groundwater protection to conduct a risk assessment. AER Directive 059: W*ell Drilling and Completion Data Filing Requirements* requires disclosure of hydraulic fracturing fluid composition and water source data on a well-to-well basis within 30 calendar days from conclusion of an operation. In addition, due to seismic activity reported in some active oil and gas areas of Alberta, the AER has implemented seismic monitoring and reporting requirements for hydraulic fracturing operators in the certain zones in such areas.

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. In particular, a scientific study commissioned by the British Columbia government regarding the environmental impacts of hydraulic fracturing for oil and gas in British Columbia found the regulatory framework to be robust, while also identifying areas for improvement. 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 the 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 the Company 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. Some provinces in which the Company operates have implemented carbon pricing mechanisms that meet or exceed the current federal benchmark carbon price of $30 per tonne (2020), which will increase $10 per tonne annually until it reaches $50 per tonne in 2022. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, 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. See "*Industry Conditions - Climate Change Regulation*" in this AIF.

Current GHG emissions legislation does not result in material compliance costs, but compliance costs may increase in the future as the federal benchmark carbon price rises in accordance with the *Greenhouse Gas Pollution Pricing Act* (Canada) 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 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.

Following the Supreme Court of Canada's decision in Redwater (the "**Redwater SCC Decision**"), oil and gas enterprises that become insolvent will generally be required to apply the value of any remaining assets to satisfy the liabilities associated with their A&R obligations in priority to the claims of secured and unsecured creditors. It is not yet clear how market participants will respond to the Redwater SCC Decision. The decision is, however, anticipated to reduce credit availability and increase the cost of credit for oil and gas enterprises with relatively high levels of A&R obligations within their asset bases. It may also cause creditors to impose additional covenants on borrowers with respect to compliance with their A&R obligations.

The Redwater proceedings have also resulted in changes to the regulatory regimes in Alberta and British Columbia. In response to the Redwater QB Decision, the AER released Bulletin 2016-16 which, among other things, implements important changes to the AER’s procedures relating to liability management ratings, licence eligibility and licence transfers. In addition, changes with respect to licence eligibility were codified in amendments to AER Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*. Among other things, Directive 067 provides the AER with broad discretion to determine if a party poses an "unreasonable risk" such that it should not be eligible to hold AER licences. The Government of British Columbia has announced similar policies following the Redwater proceedings. In particular, the Liability Management Program in BC determines is a permit holder is high risk and is required to pay a security deposit. In May of 2019, the BCOGC introduced the *Dormancy and Shutdown Regulation*, introducing mandatory timelines for oil and gas site remediation. See "*Industry Conditions - Liability Management Rating Programs*" in this AIF.

These changes may impact the Company’s ability to transfer our licences, approvals or permits, and may result in increased costs and delays or require changes to, or the abandonment of, projects and transactions. As a result of the current economic environment, the number of orphaned wells in Alberta and British Columbia has increased significantly and, accordingly, the aggregate value of the A&R liabilities assumed by the OWA in Alberta and the OSRF in British Columbia has increased and may continue to increase. While the Redwater SCC Decision may reduce the A&R liabilities ultimately assumed by the OWA and the OSRF in the long-term, their A&R liabilities will remain at elevated levels until a significant number of orphaned wells are decommissioned. As a result, the OWA and the OSRF may seek additional funding for such liabilities from industry participants, including the Company through an increase in its 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 SCC Decision 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, our business, financial condition, results of operations and cash flows.

LEGAL PROCEEDINGS

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, $45.6 million in damages for breach of contract and lost opportunity or, alternatively, an accounting of 20% of the net revenue from primary production conducted by PPR Canada's predecessors from the acquired properties. At the outset of the trial in 2011, IFP amended its claim to increase the damages sought to $56.7 million, plus interest and costs. In a decision issued in 2014, the Court of Queen's Bench of Alberta ruled in favour of the defendants and dismissed IFP's claim. 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 the fourth quarter of 2015. In May 2017, in a two-to-one majority decision, the Court of Appeal allowed the appeal and held that IFP has a 20% working interest in the Eyehill Creek properties. The Court found that IFP is entitled to an accounting for its proportionate share of the net revenue realized from primary production at Eyehill Creek, and remitted the calculation of net revenue to the Court of Queen's Bench for determination. In August 2017, the defendants applied to the Supreme Court of Canada for leave to appeal the Court of Appeal decision. In April 2018, the Supreme Court of Canada refused leave to appeal, with the result that IFP is, pursuant to the Court of Appeal decision, entitled to an accounting for profits from the affected properties from 2002 forward. Although the final outcome of this case remains uncertain in light of the calculation issues left unresolved by the Court of Appeal decision and sent back to the Court of Queen's Bench for further determination, on the available facts the Company does not expect the ultimate disposition of the matter to have a material effect on its business.

In September 2013, LPRI commenced arbitration proceedings under the North American Free Trade Agreement ("**NAFTA**") against the Government of Canada for actions taken by the Government of Quebec in 2011 to cancel, without compensation, oil and gas mining rights under a portion of the Saint Lawrence River - including an exploration permit covering 33,460 acres previously held by LPR Canada. LPRI believes that the cancellation was a violation of NAFTA by Quebec, including Articles 1105 (Minimum Standard of Treatment) and 1110 (Expropriation) thereof, for which the Federal Government is responsible, and seeks monetary damages to compensate for its sunk costs and lost development opportunity. The Government of Canada defended the claim. A 10-day hearing before a NAFTA tribunal was completed in October 2017 with closing arguments heard in November 2017. The parties continue to await the tribunal's decision. There can be no assurance as to the outcome of the proceedings, either with respect to the tribunal's conclusions on the substantive merits of the claim or any determination of compensation thereunder.

The Company is and was not during 2019 otherwise a party to, and its property is and was not during 2019 otherwise the subject of, any legal proceedings that involves a claim for damages (exclusive of interest and costs) in an amount greater than 10% of the Company's current assets, and the Company does not know of any such legal proceeding to be contemplated.

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, our independent auditor, and Sproule, our independent qualified reserves evaluator under NI 51-101.

The designated professionals of Sproule as a group, at the time of preparing its report, 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 in the context of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to Prairie Provident is filed under the Company's company profile on SEDAR at www.sedar.com, including financial information provided in its comparative annual financial statements and management's discussion and analysis for the year ended December 31, 2019. 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, is contained in the information circular for the most recent meeting of Prairie Provident shareholders involving the election of directors.

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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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, 2019, 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, 2019	Canada				
Total			**Nil**	**437,739**	**Nil**	**437,739**

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, 2019)".

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

Jan / 29 /2020 mmm/dd/yyyy

Original Signed by Tamara Warren, P.Eng.

Tamara Warren P.Eng.
Petroleum Engineer

Original Signed by Tamara Warren, P.Eng.
on behalf of Barrett R. Hanson, P.Eng.

Barrett R. Hanson, P.Eng.
Senior Petroleum Engineer

Original Signed by Ian K. Kirkland, P.Geol.

Ian K. Kirkland, P.Geol.
Senior Geologist

Original Signed by Alec Kovaltchouk, P.Eng.

Alec Kovaltchouk, P.Eng.
VP, Geoscience

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**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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 Reserves Committee of the board of directors of the Company has:

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

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

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

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

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

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

(c) the content and filing of this report.

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

DATE: March 26, 2020

(signed) "Tim Granger"
Tim Granger
President and Chief Executive Officer

(signed) "Tony van Winkoop"
Tony van Winkoop
Vice President, Exploration

(signed) "Patrick McDonald"
Patrick McDonald
Director

(signed) "Derek Petrie"
Derek Petrie
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.