HIGHWOOD OIL COMPANY LTD.

(formed pursuant to the Amalgamation on January 23, 2019 of Highwood Oil Company Ltd. and Predator Blockchain Capital Corp.)

AMENDED AND RESTATED ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2018

May 22, 2019

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CERTAIN DEFINITIONS

In this Annual Information Form, capitalized terms shall have the meanings set forth below:

Selected Defined Terms

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

"**Amalgamation**" means the amalgamation under the ABCA, pursuant to an amalgamation agreement dated December 20, 2018 between Predecessor Highwood and PBC, whereby each PBC Share was exchanged at a ratio of 53:1 Common Share and each Predecessor Highwood Share was exchanged for one Common Share at a deemed price of $9.00 per Common Share;

"**Annual Information Form**" means this Amended and Restated Annual Information Form;

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

"**Common Shares**" means common voting shares in the capital of Highwood as presently constituted;

"**Corporation**" or "**Highwood**" means Highwood Oil Company Ltd., and, when used in the context of describing the Corporation's assets and business, includes its predecessor Predecessor Highwood;

"**Capital Pool Company**" or "**CPC**" means a corporation:

(a) that has filed and obtained a receipt for a preliminary CPC prospectus from one or more of the securities regulatory authorities in compliance with Policy 2.4; and

(b) in regard to which a final bulletin has not yet been issued by the TSX Venture Exchange.

"**GAAP**" means generally accepted accounting principles for publicly accountable enterprises in Canada, which is currently in accordance with IFRS;

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta;

"**GLJ Report**" means the report prepared by GLJ and dated March 29, 2019 evaluating the crude oil, natural gas, and natural gas liquids attributable to Highwood's properties at December 31, 2018;

"**IFRS**" means International Financial Report Standards as issued by the International Accounting Standards Board;

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

"**NI 51-102**" means National Instrument 51-102 — *Continuous Disclosure Obligations* of the Canadian Securities Administrators;

"**PBC**" means Predator Blockchain Capital Corp., a corporation incorporated pursuant to the provisions of the ABCA on January 25, 2018, which completed the its initial public offering as a CPC on April 3, 2018;

"**PBC Share**" means a common voting shares in the capital of PBC;

"**Predecessor Highwood**" means the private, Calgary, Alberta, based oil and gas exploration, development and production company incorporated under the ABCA on August 24, 2012 that amalgamated with PBC pursuant to the Amalgamation;

“**Predecessor Highwood Share**” means a common voting shares in the capital of Predecessor Highwood;

“**Policy 2.4**” means the TSX Venture Exchange’s Policy 2.4 entitled “*Capital Pool Companies*”;

“**Qualifying Transaction**” means a transaction whereby a CPC acquires “Significant Assets” (as defined in Policy 2.4), other than cash, by way of purchase, amalgamation, merger or arrangement with another Company or by other means; and

“**Shareholder**” means a holder of record of one or more Common Shares.

Certain other terms used in this Annual Information Form 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.

Selected Technical Terms

“**abandonment and reclamation costs**” means all costs associated with the process of restoring a reporting issuer’s property that has been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities;

“**associated gas**” means the gas cap overlying a crude oil accumulation in a reservoir;

“**basin**” means a large natural depression on the earth’s surface in which sediments generally brought by water accumulate;

“**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), as amended from time to time;

“**conventional natural gas**” means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features;

“**crude oil**” means a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas;

“**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;

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

“**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;

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

"**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well;

"**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest". The field name refers to the surface area, although it may refer to both the surface and the underground productive formations;

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the reporting issuer 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 paragraph (a);

"**formation**" means a layer of rock which has distinct characteristics that differ from nearby rock;

"**future income tax expenses**" means expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated;

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs;

"**gross**" means:

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

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

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

"**heavy crude oil**" means crude oil with a relative density greater than 10° API gravity and less than or equal to 22.3° API gravity;

"**light crude oil**" means crude oil with a relative density greater than 31.1° API gravity;

"**medium crude oil**" means crude oil with a relative density that is greater than 22.3° API gravity and less than or equal to 31.1° API gravity;

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases;

"**natural gas liquids**" or "**NGLs**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates;

"**net**" means:

(a) in relation to the Corporation's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interest in production or reserves;

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

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

"**operating costs**", see "production costs";

"**possible reserves**" means those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves;

"**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;

"**production**" means the cumulative quantity of petroleum that has been recovered at a given date. Recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas;

"**production costs**" (or "**operating 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 production costs are:

(a) costs of labour to operate the wells and related equipment and facilities;

(b) costs of repairs and maintenance;

(c) costs of materials, supplies and fuel consumed, and supplies utilized, in operating the wells and related equipment and facilities;

(d) costs of well services; and

(e) taxes, other than income and capital taxes;

"**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties;

"**proved property**" means a property or part of a property to which reserves have been specifically attributed;

"**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;

"**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 (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates being "proved reserves", "probable reserves" and "possible reserves";

“**reservoir**” means a subsurface rock unit that contains an accumulation of petroleum;

“**resources**” means petroleum quantities that originally existed on or within the earth’s crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Total resources is equivalent to total petroleum initially-in-place;

“**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;

“**solution gas**” means natural gas dissolved in crude oil;

“**stratigraphic test well**” means the 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:

(a) “exploratory type” if not drilled into a proved property; or

(b) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”;

“**support equipment and facilities**” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices;

“**undeveloped reserves**” are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status;

“**unproved property**” means a property or part of a property to which no reserves have been specifically attributed; and

“**working interest**” means the net interest held in an oil and natural gas property which normally bears its proportionate share of the costs of exploration, development and operations as well as any royalties or other production burdens.

ABBREVIATIONS AND CONVERSION

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

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbl	one thousand barrels	MMcf	million cubic feet
MMbbl	one million barrels	Mscf	thousand standard cubic feet
bbl/d	barrels per day	Bcf	billion cubic feet
bopd	barrels of oil per day	Mcf/d	thousand cubic feet per day
NGL	natural gas liquids	MMcf/d	million cubic feet per day
		MMscf/d	million standard cubic feet per day
		MMBTU	million British Thermal Units
		MMBTU/d	million British Thermal Units per day

Other	
BOE or boe	barrel of oil equivalent is derived by converting natural gas to oil in the ratio of six Mcf of natural gas to one bbl of oil. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.**
boe/d	barrels of oil equivalent per day
Mboe	one thousand barrels of oil equivalent
MMboe	one million barrels of oil equivalent
M	thousand
ft	feet
km	kilometre
km^2	square kilometres
m^3	cubic metre
API	American Petroleum Institute
° API	is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids
$000s or M$	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
kWh	kilowatt-hour

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

To convert from	To	Multiply by
BOE	Mcf	6.0
Mcf	m^3	28.174
m^3	cubic feet	35.315
bbl	m^3	0.159
m^3	bbl	6.290
ft	metres	0.305
metres	ft	3.281
miles	km	1.609
km	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

INFORMATION

The information in this Annual Information Form is stated as at December 31, 2018 for the Corporation, unless otherwise indicated. For an explanation of the capitalized terms and expression and certain defined terms, see "*Certain Definitions*" and "*Abbreviations and Conversion*". All dollar amounts set forth in this Annual Information Form are in Canadian dollars, unless otherwise indicated.

The information in this Annual Information Form is given as of December 31, 2018 for the Corporation, unless otherwise indicated. All dollar amounts set forth in this Annual Information Form are in Canadian dollars, unless otherwise indicated.

NON-GAAP TERMS

This Annual Information Form refers to certain financial measures that are not determined in accordance with GAAP. Since non-GAAP measures do not have a standardized meaning prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other companies, securities regulations require that non-GAAP measures are clearly defined, qualified and reconciled to their nearest GAAP measure. Except as otherwise indicated, these non-GAAP measures are calculated and disclosed on a consistent basis from period to period. Specific adjusting items may only be relevant in certain periods.

The intent of non-GAAP measures is to provide additional useful information with respect to Highwood's operational and financial performance to investors and analysts though the measures do not have any standardized meaning under IFRS. The measures should not, therefore, be considered in isolation or used in substitute for measures of performance prepared in accordance with IFRS. Other issuers may calculate these non-GAAP measures differently.

In particular, the term "netback" is used in this Annual Information Form and readers should be cautioned that netback is not defined by GAAP and may not be comparable to similar measures presented by other companies. Management believes this is a useful metric in providing a comparison of relative overall performance between companies as it is a common metric used by other companies operating in the oil and gas industry. Management uses the metric to assess the Corporation's overall performance relative to that of its competitors and for internal planning purposes.

"Netback" is a non-GAAP financial measure and is calculated as revenues net of royalties, less transportation and processing charges and operating expenses and then divided by BOE or Mcf sold.

"Normalized operating and transportation expense" is not defined under IFRS, and may not be comparable with similar measures presented by other companies. Normalized operating and transportation expense is normalized in order to present what the operating and transportation expense per boe would be for the Corporation's producing assets, assuming no unusual or non-recurring expenditures.

"Adjusted G&A per boe" is not defined under IFRS, and may not be comparable with similar measures presented by other companies. Adjusted G&A per boe is normalized in order to present what the G&A expense per boe for the Corporation would be assuming no unusual or non-recurring expenditures.

For more information with respect to financial measures which have not been defined by GAAP, including reconciliations to the closest comparable GAAP measure, see the "*Non–GAAP Measures*" section of the Corporation's management discussion and analysis accompanying its most recent audited annual financial statements which are available on SEDAR.

FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events of our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek," "anticipate," "budget," "plan," "continue," "estimate," "expect," "forecast," "may," "will," "project," "predict," "potential," "target," "intend," "could," "might," "should," "believe," and similar expressions. In addition, there are forward-looking statements in this Annual Information Form under the headings: "Statement of Reserves Data and Other Oil and Gas Information" as to our reserves and future net revenues from our reserves, pricing and inflation rates and future development costs; as to the development of our proved undeveloped reserves and probable undeveloped reserves; as to our future development activities, forward contracts and transportation commitments, reclamation and abandonment obligation, tax horizon, and exploration and development activities and production estimates. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only to estimates as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In addition to the forward-looking statements identified above, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the performance characteristics of our crude oil and natural gas properties; crude oil and natural gas production levels; the size of the crude oil and natural gas reserves and of our contingent resources, projections of market prices and costs; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; treatment under governmental regulatory regimes and tax laws; Impacts of current commodity prices on the Corporation, including with respect to abandonment and reclamation obligations; budget expectations; and capital expenditure programs.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. In addition, these risks and uncertainties are material factors affecting the success of our business. Such factors include, but are not limited to: declines in crude oil and natural gas prices; various pipeline constraints; the payment of dividends, if any; variations in interest rates and foreign exchange rates; stock market volatility; uncertainties relating to market valuations; refinancing risk for existing debt and debt service costs; access to external sources of capital; risks associated with our hedging activities; third-party credit risk; risks associated with the exploitation of our properties and our ability to acquire reserves; government regulation, policy and control and changes in governmental legislation; changes in income tax laws, royalty rates and other incentive programs; uncertainties associated with estimating crude oil and natural gas reserves and resources; risks associated with acquiring, developing and exploring for crude oil and natural gas and other aspects of our operations; our reliance on hydraulic fracturing; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in climate change laws and other environmental regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; risks of non-cash losses as a result of the application of accounting policies; our operating activities and ability to retain key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; risks for United States ("**US**") and other non-resident Shareholders; risks described in further detail under "*Risk Factors*" herein; and other factors, many of which are beyond our control.

The actual results could differ materially from those results anticipated in these forward-looking statements, which are based on assumptions, including as to the market prices for crude oil and natural gas; the continuation of the present policies of the Board relating to management of Highwood, and the payment of dividends, capital expenditures and other matters; the continued availability of capital and skilled personnel, acquisitions of reserves and undeveloped lands; the continuation of the current tax and regulatory regime and other assumptions contained in this Annual Information Form.

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

The estimates of future production may be considered to be future-oriented financial information or a financial outlook for the purposes of applicable Canadian securities laws. Financial outlook and future-oriented financial information contained in this Annual Information Form about prospective financial performance, financial position or cash flows are based on assumptions about future events, including economic conditions and proposed courses of action, based on management’s assessment of the relevant information currently available, and to become available in the future. In particular, this Annual Information Form contains projected operational information for 2019. These projections contain forward-looking statements and are based on a number of material assumptions and factors. Actual results may differ significantly from the projections presented herein. These projections may also be considered to contain future-oriented financial information or a financial outlook. The actual results of Highwood’s operations for any period could vary from the amounts set forth in these projections, and such variations may be material. See above for a discussion of the risks that could cause actual results to vary. The future-oriented financial information and financial outlooks contained in this Annual Information Form have been approved by management as of the date of this Annual Information Form. Readers are cautioned that any such financial outlook and future-oriented financial information contained herein should not be used for purposes other than those for which it is disclosed herein. Highwood and its management believe that the prospective financial information has been prepared on a reasonable basis, reflecting management’s best estimates and judgments, and represent, to the best of management’s knowledge and opinion, Highwood’s expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results.

Management of the Corporation has included the above summary of assumptions and risks related to forward-looking information provided in this Annual Information Form in order to provide Shareholders with a more complete perspective on the Corporation’s current and future operations and such information may not be appropriate for other purposes. The Corporation’s actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that the Corporation will derive therefrom. These forward-looking statements are made as of the date of this Annual Information Form and the Corporation disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

NOTE REGARDING DRILLING LOCATIONS

The references to drilling locations that are contained herein have been prepared by qualified reserves evaluators from Highwood as at the date hereof. Of the 230 drilling locations identified herein, all are 100% interests net to Highwood with the exception of Clearwater, which are 50% interests net to Highwood, and Deer Mountain & Fireweed which are various interests. Of the total drilling locations 13 are proved locations, 17 are probable locations and 200 are unbooked locations. Proved locations and probable locations are derived from the GLJ Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on 3-D seismic response within interpreted channel sequences. Unbooked locations do not have attributed reserves or resources. There is no certainty that Highwood will drill any or all booked or unbooked drilling locations and, if drilled, there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which Highwood actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

CORPORATE STRUCTURE

Name, Address and Incorporation

Highwood was formed by amalgamation under the ABCA.

Effective January 23, 2019, Predecessor Highwood and PBC completed the Amalgamation to form the Corporation, being a new corporation also named "Highwood Oil Company Ltd." The Amalgamation constituted PBC's Qualifying Transaction.

On January 29, 2019, the Common Shares began trading on the TSX Venture Exchange under the symbol "HOCL". The Corporation is a reporting issuer in the provinces or British Columbia, Alberta, and Saskatchewan.

The Amalgamation was a reverse takeover and Predecessor Highwood was the acquiror.

Highwood's head office is located at 900, 222 – 3rd Avenue SW, Calgary, Alberta, and its registered office is located at 1000, 250 – 2nd Street SW, Calgary, Alberta.

PBC was incorporated pursuant to the provisions of the ABCA on January 25, 2018.

Predecessor Highwood was incorporated under the ABCA on August 24, 2012.

Intercorporate Relationships

The Corporation does not have any subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

As at the date of this Annual Information Form, and as a result of the Amalgamation, the Corporation's business is the business of Predecessor Highwood combined with the business of PBC. Although the business of PBC is also part of the Corporation's business it is not material to a reader as PBC was a capital cool company ("**CPC**").

As a CPC, PBC's sole business since its incorporation was to identify and evaluate opportunities for the acquisition of an interest in assets or businesses with a view to completing a Qualifying Transaction which occurred upon completion of the Amalgamation.

ALL INFORMATION HEREIN, UNLESS IDENTIFIED AS PBC DISCLOSURE, IS DISCLOSURE RELATING TO HIGHWOOD AS AT THE DATE OF THIS ANNUAL INFORMATION FORM.

AS AT DECEMBER 31, 2018, PBC HAD NOT COMPLETED A QUALIFYING TRANSACTION AND THEREFORE DID NOT OWN ANY ASSETS OTHER THAN CASH LESS LIABILITIES OF APPROXIMATELY $507,000.

Three Year History

In Q1 2017, the Corporation acquired oil & gas properties from Mosaic Energy Ltd. for gross proceeds of $33,000,000 before closing adjustments, comprising of approximately 2,500 boe/d of production predominantly in the Gilby and Niton areas of Alberta. The Corporation operated these assets from February 2017 to April 2017 and subsequently disposed of the properties en bloc to Journey Energy Inc. in April 2017. Both transactions were arm's length transactions.

Throughout 2018, the Corporation acquired the outstanding working interests in the Wabasca River Pipeline System, a 210 km crude oil sales line with capacity to deliver 20,000 bbl/d of crude to the Plains Rainbow Pipeline in Northern Alberta. Total acquisition costs after standard closing adjustments were approximately $7,540,000.

Current throughput on the line has averaged 4,600 bbl/d over the last three months as of the date of this Annual Information Form.

In October, 2017, the Corporation entered into a joint venture agreement with an arm's length party and jointly acquired 196 gross sections of mineral rights in the Clearwater Formation, split between the areas of Jarvie/Newbrook (82 gross, 42 net sections to the Corporation) and Nipisi/Marten (114 gross, 57 net sections to the Corporation) Alberta. In September 2018, the Corporation and the joint venture partner sold a 4%, non-deduct, overriding royalty interest in the lands for gross proceeds of $12,000,000 ($6,000,000 net to the Corporation). The proceeds are held in trust pending the Corporation and the joint venture partner drilling a minimum of 8 wells in the Clearwater Formation prior to March 31, 2020. To date, the Corporation has completed seven gross wells in the Clearwater Formation and received $10,500,000 ($5,250,000 net to the Corporation) from the escrow agent. The Corporation had a total of 196 gross and 99 net sections in the Clearwater Formation as of December 31, 2018.

In January, 2019, the Corporation entered into an amalgamation agreement with Predator Blockchain Capital Corp. for the purposes of completing a Qualifying Transaction. PBC completed a consolidation of its 10,000,000 outstanding Common Shares at a ratio of approximately 1:53 and issued 5,751,804 post-consolidated Common Shares to Highwood shareholders at a deemed value of $9.00 per share under a prospectus exempt private placement.

In January 2019, the Corporation completed a private placement of 7,600 Common Shares at a price of $9.00 per Common Share for aggregate proceeds of $68,400.

Recent Developments

Operational updates subsequent to the period ended December 31, 2018 include:

To date in 2019, the Corporation has drilled 3 gross (1.5 net) Clearwater wells and completed 3 hydraulic fracturations on existing wellbores. The Corporation has also acquired 30 sections gross (16 net) of additional lands in the Clearwater Formation bringing total gross Clearwater Formation sections to 226 gross (115 net) as of the date of this Annual Information Form.

On April 29, 2019, the Corporation completed the acquisition of an arm's-length private company with production in Saskatchewan for a total purchase price of $5.0 million before ordinary closing adjustments (the "**Saskatchewan Acquisition**"). The acquired company has 7 gross (5.5 net) wells producing approximately 250 bbl/d of oil from the Tilston Formation. Following ordinary closing adjustments, the purchase price comprised $3,535,000 paid in cash, a $600,000 holdback and $1,550,000 paid in Common Shares (at $23.51 per share for a total of 65,935 Common Shares). Fifty percent (50%) of such Common Shares are subject to a contractual 90-day hold period from the date of closing and the remaining Fifty percent (50%) of such Common Shares are subject to a contractual 180-day hold period from the closing date. See "*Escrowed Securities and Securities Subject to Contractual Restriction on Transfer*".

On May 16, 2019, the Corporation entered into an agreement with a publicly traded oil and gas exploration and production company to purchase oil assets in the Peace River Oil region of Northern Alberta for a total transaction value of $93.8 million, comprised of cash considerations of $88.8 million and equity consideration of $5.0 million prior to customary closing adjustments (the "**PROP Acquisition**"). The PROP Acquisition includes a 55% operated working interest ("**WI**") in the Peace River Oil Partnership (the "**PROP**") (8,000 boe/d gross production, 4,400 boe/d net production to HOCL WI, 89% oil and liquids). The PROP Acquisition will be funded with $61.5 million of cash, $19.0 million in deferred payment / vendor take-back consideration, $3.0 million of oil price escalator provisions, $5.3 million of assumed working capital deficit and $5.0 million of HOCL equity. Closing of the PROP Acquisition is expected to occur prior to July 31, 2019, subject to the satisfaction of customary closing conditions, including regulatory approvals.

Significant Acquisitions

During the period ended December 31, 2018, the Corporation did not complete any significant acquisitions as defined in NI 51-102.

DESCRIPTION OF THE BUSINESS

General

Highwood is a Canadian junior oil and natural gas company focused on growth through exploration, development, production and acquisition programs in the Western Canadian Sedimentary Basin ("**WCSB**"). The Corporation commenced oil and gas activities in August 2012. Its core management team has previously started and grown several successful junior oil and gas companies.

The Corporation's core growth areas are all located within Alberta. The Corporation has assembled its current land and producing asset holdings through multiple acquisitions completed since 2012. The Corporation's two core growth areas in the WCSB are Jarvie/Nipisi/Marten Hills (Clearwater Formation) and Red Earth (Keg River Formation). The Corporation holds approximately 226 gross (115 net) sections of mineral rights in the Clearwater Formation and 246 gross (208 net) sections of mineral rights in the Keg River Formation. See "*Highwood Assets*".

The Corporation's Assets have had 9,909 gross (8,849 net) MBoe of proved plus probable reserves assigned, as at December 31, 2018, by GLJ, the Corporation's independent qualified reserves engineers. See "*Statement of Reserves Data and Other Oil and Gas Information*". The Corporation's Assets have an estimated 2019 average annual production of approximately 1,371 bbl/d of proved developed producing reserves as per the December 31, 2018 GLJ Reserve Report, which is being produced predominantly from the Keg River and Clearwater Formations.

To date, the Corporation has raised $11,568,400 through private placement equity financings and completed a number of strategic land and producing asset acquisitions to cost-effectively build its WCSB land position.

Business Strategy

The Corporation's long-term business strategy is to increase shareholder value by growing its asset base in the WCSB and to exploit and develop this area to increase reserves, production and cash flows at an attractive return on invested capital. The Corporation seeks to execute this strategy by: (i) drilling and developing its undeveloped land position; (ii) adopting and employing advanced drilling and completion techniques; (iii) enhancing returns by focusing on operational and cost efficiencies; and (iv) pursuing strategic asset or land acquisitions with significant potential synergies.

Competitive Advantages

Management believes the Corporation has several competitive advantages that will help it execute its business strategy successfully:

- ***Multi-Year Prospective Drilling Inventory***

  The Corporation's drilling strategy is to engage in development drilling with low capital exposure per well. In the Jarvie/Nipisi/Marten Hills areas, the Corporation has an inventory of 200 gross horizontal Clearwater drilling locations. The Corporation intends on using positive cashflows from existing operations along with proceeds receivable from a royalty divestiture to drill and complete eight to sixteen gross horizontal Clearwater wells (targeting both the Upper and Lower Clearwater sands) in 2019 and 2020. See "*Highwood Assets – Multi-Year Prospective Drilling Inventory*". The Corporation owns an average 51% interest in the mineral rights in the Jarvie/ Nipisi/Marten Hills area with an arms length joint venture party owning the other 49%.

- ***Operated Assets, High Working Interest***

  95% of the Corporation's Red Earth production is operated on behalf of the Corporation and the Corporation has an average working interest of 95% in its Red Earth Keg River mineral rights and production. Directing the operation of its assets allows the Corporation to dictate its organic growth opportunities while controlling the cost and timing of its preferred development plan. Directing the operation of its properties further allows the Corporation to achieve operating benefits as it consolidates future core areas.

- ***Conservative Balance Sheet Target***

  The Corporation's long-term corporate goal is to maintain funds flow from operations and a conservative capital structure to provide the financial flexibility necessary for continued success in executing its acquisition program and organic growth.

- ***Management Team with a History of Creating Value for Shareholders***

  The Corporation's senior management team has extensive experience in the oil and natural gas business in the WCSB. The Corporation believes that its management team has the necessary skills and experience to build the Corporation into a successful growth-oriented, exploration and development focused oil and natural gas company supported by their experience and past involvement and success with growing several public and private companies from start-up to eventual sale. the Corporation's management is experienced in drilling, completing and operating vertical and horizontal wells and acquiring assets in a number of areas and play types, including the areas currently owned, in the WCSB.

Specialized Skill and Knowledge

The Corporation employs individuals with various professional skills in the course of pursuing its business plan. In addition, the Corporation has available to it various specialized consultants to assist it in various areas where it feels it doesn't need full time employees. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are widely available in the industry. Drawing on significant experience in the oil and natural gas business, the Corporation believes its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows the Corporation to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The oil and natural gas industry is very competitive, and the Canadian Association of Petroleum Producers estimates that there are over 1,000 exploration and production companies in Canada. The Corporation believes that it has a strong competitive position in the areas in which it operates, see "*Highwood Reserves – Disclosure of Reserves Data – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties"*, and "*Highwood Assets*". The Corporation's business strategy is to develop and grow production in core areas to enable it to have operating cost advantages and operating efficiencies in each core area.

Companies operating in the petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and the Corporation is required to compete with a substantial number of other entities which may have greater technical or financial resources. With the maturing nature of the WCSB, the access to new prospects is becoming more and more competitive and complex.

The Corporation attempts to enhance its competitive position by operating in areas where it believes its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. Management believes that the Corporation will be able to explore for and develop new production and reserves with the objective of increasing its cash flow and reserve base. See "*Risk Factors – Competition*".

Cycles

The Corporation's business is generally not cyclical. The exploration for and the development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including "freeze-up" and "break-up", affect access in certain circumstances. See "*Risk Factors – Seasonality*".

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness of the Corporation. For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of the Corporation see "*Industry Conditions – Environmental Regulation*" and "*Risk Factors – Environmental*".

Employees

As at the date of this Annual Information Form, Highwood had eight full time employees and five contractors located at its office in Calgary. There are currently two employees and fourteen contractors located in our field locations.

Environmental, Health and Safety Policies

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

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

The Corporation also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Corporation's environmental and occupational health and safety management systems are designed to manage such risks in the Corporation's business and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits.

Reorganizations

On January 23, 2019, Highwood Oil Company Ltd. amalgamated with PBC and continued, on a go-forward basis, as Highwood Oil Company Ltd. The Amalgamation constituted PBC's Qualifying Transaction under Policy 2.4. and thereafter the Common Shares were listed for trading on the TSX Venture Exchange under the symbol "HOCL".

HIGHWOOD ASSETS

All information regarding the Assets contained herein, including all reserves and related information, financial information, has been derived in part from information provided to GLJ Petroleum Consultants Ltd. See "*Risk Factors*".

The assets that comprise the Corporation's two core growth areas are the Red Earth Assets and the Jarvie/Nipisi/Marten Hills Assets. The Corporation also has non-core assets located in the Provinces of Alberta and British Columbia. The assets that comprise the Corporation's non-core assets are the Minor Assets outlined below.

Core Assets

The majority of the Corporation's current production comes from the Red Earth area of Alberta. The Corporation acquired these assets in 2014 from a Canadian publicly traded oil & gas company for gross proceeds of $46,800,000 before closing adjustments. Since acquisition, the Corporation has been focused on optimizing the field through a series of workovers, recompletions and cost reduction activities. The Corporation drilled its first two gross (1.5 net) wells in the area in the first quarter of 2018. Current production from the field is approximately 1,250 bbl/d of light oil. The Corporation has associated abandonment and reclamation obligations of approximately $24.9 million (undiscounted) in the Red Earth area. Throughout 2018, the Corporation acquired the outstanding working interests in the Wabasca River Pipeline System, a 210 km crude oil sales line with capacity to deliver 20,000 bbl/d of crude to the Plains Rainbow Pipeline in Northern Alberta. The Wabasca River Pipeline System is connected to one of the Corporation's southern batteries in Red Earth and the Corporation ships all production from the Red Earth Area down the line.

The Corporation's second core area of Jarvie/Newbrook/Martin/Nipisi in its infancy of development with 7 gross (3.5 net) wells having been drilled between the third quarter of 2018 and today. Together with their joint venture partner in the area, the parties have amassed a land position of 226 gross (115 net to the Corporation) sections of Clearwater mineral rights as of the date of this Annual Information Form. In the third quarter of 2018 the parties divested of a 4%, non-deduct royalty over the jointly held Clearwater mineral rights for gross proceeds of $12,000,000 ($6,000,000 net to the Corporation). As a condition of the royalty divestiture, the parties must drill a minimum of eight wells in the formation prior to March 31, 2020. Should total drill, completion and equipping costs be less than $1,500,000 per well, the parties will be required to drill additional wells prior to September 30, 2020 in order to recoup the remaining funds.

Minor Assets

The Corporation acquired the Minor Assets pursuant to several separate acquisitions from arm's length parties. The Minor Assets were assigned a smaller reserve valuation than the Core Assets in the December 31, 2018 GLJ Report.

The Corporation owns a 50% working interest in a producing oil well north of Swan Hills, Alberta. Current production from the well averages 20 bbl/d of light sweet oil. The Corporation acquired the well in the transaction with Equal Energy Ltd. and did not dispose of the well in subsequent divestitures of the Equal assets. At December 31, 2018, the property was assigned 117 Mboe of proved reserves and a total proved reserve value of $2,483,000 (10% DCF).

The Corporation has a 55% average working interest in 53.4 sections of Doig lands in Fireweed, British Columbia. There is no current production from the field. At December 31, 2018, the field was assigned 552 MBoe of proved reserves and a total proved reserve value of $3,294,000 (10% DCF). Conditional on anticipated economics and access to capital, the Corporation would plan on developing these mineral interests over the next two to three years. The Doig lands were obtained in a related party transaction in September 2017 for consideration of $650,000.

The Corporation has a 67% working interest in 20.7 sections of Viking land in the Alliance area of Alberta. There is no current production from the field. At December 31, 2018 there were no reserves assigned in the GLJ Report to this property.

Overview of the Corporation’s Red Earth Assets

The Corporation’s core production area is the greater Red Earth area of North Central Alberta focusing entirely on Keg River light oil. Industry participants have been pursuing the life reserve conventional Keg River light for over 30 years initially by vertical wells and later by horizontal wells. In recent years, the resource has been further advanced by use of multi-stage fracking technologies in both vertical and horizontal wells to access bypassed and compartmentalized hydrocarbon.

The Corporation’s Red Earth properties are further sub-divided into 6 strikes: North Senex. South Senex, House Creek, Trout, Kidney and Panny. The Corporation holds 246 gross sections (208 net), of which 57% (net) is considered developed. The Corporation’s Red Earth assets have 7,974 gross (7,108 net) MBoe (100% Oil) of proved plus probable assigned reserves as of December 31, 2018, by GLJ, the Corporation’s independent qualified reserves engineers (see “*Highwood Reserves*”). The Corporation has an estimated 2019 average annual production of approximately 1,500 bbl/d, of which approximately 1,371 is being produced from the Red Earth assets.

Multi-Year Prospective Recompletion Candidates and Drilling Inventory

The Corporation’s strategy in Red Earth is to recomplete a number of producing low decline (less than 10%) Keg River oil wells with low water cuts requiring minimal capital to increase production and to add additional producing reserves. Secondarily, the Corporation has a multi-year inventory of 2P undeveloped Keg River drilling locations in areas that have low recoveries to date and require multistage horizontal wells to harvest compartmentalized reserves.

Currently, management has 41 re-completion candidates and 15 2P drilling locations in the GLJ Report.

The Keg River Oil inventory based on regional mapping of the Devonian Platform Carbonate sequence defined as barrier to lagoonal dolomitic sequences that prograde regionally from southwest to northeast. Pay delineation was conducted by using density porosities greater than 4% and primary water saturation calculations less than 50%. Permeability calculations provided by a multitude of regionally cored wells, typically with permeability measurements in the 0.1 to 1500mD, were also used to define areas of low recoveries. Typically, the bypassed pay is witnessed in the micro to meso permeable rock measurements with permeability measurements in the 0.1 to 50 mD range. Primary recoveries factors range from less than 2% to as much as 20% whilst secondary recoveries via waterflood are as high as 30% on a single section basis. The oil typically is trapped in post depositional faulted up dip horst blocks with oil over a regional the salt water aquifer. Panny and North Senex are the two main areas with the recompletion and drilling inventory and is identified where recovery factors are much less than 15%, average permeability is low, net pays are greater than 10m and production has less than 50% water cut.

There is no certainty that the Corporation will drill any of the potential drilling opportunities identified herein and, if drilled, there is no certainty that such locations will result in additional oil and gas reserves or production. The drilling opportunities on which the Corporation actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the potential drilling opportunities have been de-risked by existing wells in relative close proximity to such potential drilling opportunity, some of other potential drilling opportunities are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and, if drilled, there is more uncertainty that such wells will result in additional oil and gas reserves or production.

Exploration and Development to Date (2018) and Future Development Plans

In 2018, the Corporation drilled 2 gross (1.5 net) horizontal Keg River wells with stage frack completions. Additionally, in 2018, the Corporation recompleted 8 existing horizontal and/or vertical wells with modern frack technologies that produced economic results. An additional 9 Keg River wells were licensed and drilled by offsetting operators in 2018, all of which is produced through the Corporation’s oil infrastructure. To date in 2019, the Corporation has re-completed 3 wells and plans to recomplete another 1-3 wells before the end of the year. Additional horizontal wells may be contemplated by Management in 2019 if improving oil prices warrant economic programs.

Infrastructure Capacity

The Corporation infrastructure has additional processing and handling capacity. With third party activity increasing in the Red Earth area, revenues are expected to increase. The Corporation also has a 200 km sales system with capacity of 20,000 bbl/d which has one terminal and feeds directly into the Plains Rainbow system.

Overview of Highwood's Jarvie/Newbrook/Nipisi/Marten Hills Rights (Clearwater Formation)

The Corporation's second core area, located in Central Alberta, exposes the company to shallow oil and natural gas prospects. Specifically, industry participants have been pursuing the Clearwater Oil play, which is a member of the Manville sands. Exploration and production of the Clearwater has evolved over time from conventional reservoirs pursued with vertical wells to a heavy oil reservoir. Technological developments, including the drilling of multilateral horizontal wells, have allowed access to the resource rich Clearwater reservoir.

The Corporation's core growth assets are the Nipisi, Marten Hills, Jarvie and Newbrook strike areas, where the Corporation holds approximately 226 gross (115 net) sections of Clearwater rights as of the date of this Annual Information Form (196 gross and 99 net at December 31, 2018). The Corporation's Clearwater Assets had 638 gross (579 net) MBoe of proved plus probable reserves assigned, as at December 31, 2018, by GLJ, the Corporation's independent qualified reserves engineers.

Multi-Year Prospective Drilling Inventory

The Corporation's drilling strategy is to engage in development drilling with low capital exposure per well and with short cycles times. Management believes that the lands have a multi-year drilling inventory based on internal estimates that could exceed 350 gross wells. The Corporation has an inventory of 11 gross multilateral drilling locations recognized in the December 31, 2018 reserve report with gross proved plus probable reserves of 510 MBoe assigned thereto.

This Clearwater inventory was created using geological and geophysical mapping that was extended to the Corporation's lands from areas of analogous commercial Clearwater production offsetting the Corporation's acreage. This geological mapping included existing vertical well data. Up to two potential drilling opportunities per zone were allocated to sections in proximity to a vertical well with bypassed pay, resulting in a total of 350 gross (175 net) potential drilling opportunity in multiple zones (Upper and Lower Clearwater). Within this potential drilling inventory, 120 gross (60 net) locations have been selected as having the lowest risk within the Corporation's lands, as they are the single closest locations to the vertical wells with bypassed pay.

There is no certainty that the Corporation will drill all of the potential drilling opportunities identified herein and, if drilled, there is no certainty that such locations will result in additional oil and gas reserves or production. The drilling opportunities on which the Corporation ultimately drills wells will depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the potential drilling opportunities have been de-risked by existing wells of other operators in relatively close proximity to such potential drilling opportunities, some of our other potential drilling opportunities are further away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations. If drilled, there is further uncertainty that such wells will result in additional oil and gas reserves or production.

Exploration and Development Drilling Plans

The Corporation intends to drill, complete and tie-in between eight and sixteen gross horizontal Clearwater wells (targeting both the Upper and Lower Clearwater) in 2019 and 2020. The locations are planned to delineate the property by targeting multiple zones (both Upper and Lower Clearwater).

Infrastructure Capacity

Initially, the planned wells will be produced via single and multi-well facilities. New production will be trucked to various sales points within western Canada including terminals owned by the Corporation.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2018. The reserves data conforms to the requirements of NI 51-101.

The reserves data set forth below is based upon an evaluation by GLJ and contained in the GLJ Report dated March 29, 2019. The preparation date of the GLJ Report is March 28, 2019. The reserves data summarizes our crude oil, natural gas and natural gas liquids reserves and the net present values of future net revenues for these reserves, using forecast prices and costs prior to provision for interest, general and administrative expenses, the impact of any hedging activities or the liability associated with the abandonment and reclamation of certain wells, pipelines and facilities. Future net revenues have been presented on a before-tax and after-tax basis. The Corporation engaged GLJ to provide an evaluation of proved and proved plus probable reserves.

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 will be attained, and variances could be material. The recovery and reserves estimates of crude oil, natural gas and natural gas liquids reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein. Readers should review the definitions contained in "*Certain Definitions – Selected Technical Terms*" in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors - Risk Relating to Our Business and Operations*".

The Report on Reserves Data by GLJ on Form 51-101F2 is attached as Schedule A to this Annual Information Form.

As per NI 51-101 product type definitions, Highwood has provided reserves data for reserves classified as Shale Gas. Highwood's gas reserves and resources in the Doig siltstone are classified as Shale Gas under NI 51-101.

Disclosure of Reserves Data

Summary of December 31, 2018 Oil and Gas Reserves – Based on Forecast Prices and Costs

	Light & Medium Oil		Heavy Oil		Shale Gas		Natural Gas Liquids		Oil Equivalent	
Reserves Category	**Gross Mbbl**	**Net Mbbl**	**Gross Mbbl**	**Net Mbbl**	**Gross MMcf**	**Net MMcf**	**Gross Mbbl**	**Net Mbbl**	**Gross Mboe**	**Net Mboe**
Proved										
Producing	3,148	2,805	86	79	0	0	0	0	3,235	2,884
Developed Non-Producing	1,627	1,475	0	0	0	0	0	0	1,627	1,475
Undeveloped	551	487	133	121	1,919	1,871	233	191	1,236	1,110
Total Proved	5,327	4,766	219	199	1,919	1,871	233	191	6,098	5,469
Total Probable	2,805	2,483	419	380	2,014	1,932	244	195	3,803	3,380
Total Proved Plus Probable	8,132	7,249	638	579	3,933	3,803	477	386	9,902	8,849

Summary of Net Present Value of Future Net Revenue – Based on Forecast Prices and Costs

	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)					Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
Reserves Category	**0% M$**	**5% M$**	**10% M$**	**15% M$**	**20% M$**	**0% M$**	**5% M$**	**10% M$**	**15% M$**	**20% M$**	**$/boe**	**$/Mcfe**
Proved												

Reserves Category	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year) 0% M$	5% M$	10% M$	15% M$	20% M$	Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year) 0% M$	5% M$	10% M$	15% M$	20% M$	Unit Value Before Income Tax Discounted at 10%/year $/boe	$/Mcfe
Producing	111,241	92,105	77,950	67,422	59,430	90,306	75,442	64,269	55,903	49,530	27.03	4.51
Developed Non-Producing	52,389	41,550	33,352	27,309	22,808	37,167	29,797	23,908	19,480	16,156	22.61	3.77
Undeveloped	23,821	16,409	11,465	8,043	5,592	17,299	11,360	7,393	4,659	2,712	10.32	1.72
Total Proved	187,452	150,064	122,767	102,775	87,831	144,772	116,598	95,570	80,041	68,398	22.45	3.74
Total Probable	126,510	81,727	56,024	40,660	30,943	91,984	59,140	39,955	28,473	21,244	16.58	2.76
Total Proved Plus Probable	313,962	231,791	178,790	143,435	118,774	236,756	175,738	135,525	108,515	89,642	20.21	3.37

Note:

(1) Unit values are based on Company Net Reserves.

Total Future Net Revenue (Undiscounted) – Based on Forecast Prices and Costs

Reserves Category	Revenue M$	Royalties M$	Operating Costs M$	Capital Development Costs M$	Aband. & Recl. Costs M$	Future Net Revenue Before Income Taxes M$	Income Tax M$	Future Net Revenue After Income Taxes M$
Proved Producing	29,8931	26,239	145,284	4,032	12,135	111,241	20,935	90,306
Proved Developed Non-Producing	133,144	12,301	55,301	7,495	5,658	52,389	15,222	37,167
Proved Undeveloped	71,576	8,855	15,401	22,205	1,293	23,821	6,522	17,299
Total Proved	503,651	47,396	215,986	33,732	19,086	187,452	42,680	144,772
Total Probable	314,724	35,697	117,496	29,182	5,839	126,510	34,526	91,984
Total Proved Plus Probable	818,375	83,093	333,482	62,914	24,924	313,962	77,206	236,756

Future Net Revenue by Product Type - Based on Forecast Prices and Costs

	Future Net Revenue Before Income Taxes (3) (Discounted at 10% per year) M$	$/boe	$/Mcfe
Proved Producing			
Light & Medium Oil (1)	75,287	26.84	4.47
Heavy Oil (1)	2,664	33.85	5.64
Shale Gas (2)	0	0.00	0.00
Total: Proved Producing	77,950	27.03	4.51
Total Proved			
Light & Medium Oil (1)	114,865	24.10	4.02
Heavy Oil (1)	4,808	24.13	4.02
Shale Gas (2)	3,094	6.15	1.02
Total: Total Proved	122,767	22.45	3.74
Total Proved Plus Probable			
Light & Medium Oil (1)	157,302	21.70	3.62
Heavy Oil (1)	14,481	25.00	4.17
Shale Gas (2)	7,007	6.87	1.15
Total: Total Proved Plus Probable	178,790	20.21	3.37

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.

Pricing Assumptions

The forecast cost and price assumptions above assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The following crude oil and natural gas benchmark reference pricing, inflation and exchange rates were utilized in the GLJ Report.

GLJ Petroleum Consultants
Crude Oil and Natural Gas Liquids
Price Forecast
Effective January 1, 2019

			NYMEX WTI Near Month Contract Crude Oil at Cushing, OK		Brent Blend Crude Oil FOB North Sea	MSW, Light Crude Oil (40 API, 0.3%S) at Edmonton	Bow River Crude Oil Stream Quality at Hardisty	WCS Crude Oil Stream Quality at Hardisty	Heavy Crude Oil Proxy (12 API) at Hardisty	Light Sour Crude Oil (35 API, 1.2%S) at Cromer	Medium Crude Oil (29 API, 2.0%S) at Cromer	Alberta Natural Gas Liquids (Then Current Dollars)			
Year	**Inflation %**	**CADUSD Exchange Rate USD/CAD**	**Constant 2019 $ USD/bbl**	**Then Current USD/bbl**	**Then Current USD/bbl**	**Then Current CAD/bbl**	**Then Current CAD/bbl**	**Then Current CAD/bbl**	**Then Current CAD/bbl**	**Then Current CAD/bbl**	**Then Current CAD/bbl**	**Spec Ethane CAD/bbl**	**Edmonton Propane CAD/bbl**	**Edmonton Butane CAD/bbl**	**Edmonton C5+ Stream Quality CAD/bbl**
2019	0.0	0.750	56.25	56.25	63.25	63.33	48.17	47.67	37.65	62.07	58.90	5.69	25.33	21.45	67.67
2020	2.0	0.770	61.76	63.00	68.50	75.32	58.94	58.44	51.21	73.82	70.05	7.20	32.39	37.66	79.22
2021	2.0	0.790	64.40	67.00	71.25	79.75	66.32	65.82	59.51	78.15	74.16	8.51	36.68	47.85	83.54
2022	2.0	0.810	65.96	70.00	73.00	81.48	68.40	67.90	61.62	79.85	75.78	9.27	39.11	57.04	85.49
2023	2.0	0.820	66.98	72.50	75.50	83.54	70.62	70.12	63.82	81.87	77.69	10.12	41.77	58.48	87.80
2024	2.0	0.825	67.93	75.00	78.00	86.06	73.23	72.73	66.45	84.34	80.04	10.42	43.03	60.24	90.30
2025	2.0	0.825	68.82	77.50	80.50	89.09	76.26	75.76	69.48	87.31	82.85	10.78	44.55	62.36	93.33
2026	2.0	0.825	70.00	80.41	83.41	92.62	79.78	79.28	73.01	90.77	86.13	11.03	46.31	64.83	96.86
2027	2.0	0.825	70.00	82.02	85.02	94.57	81.74	81.24	74.96	92.68	87.95	11.27	47.28	66.20	98.81
2028	2.0	0.825	70.00	83.66	86.66	96.56	83.72	83.22	76.95	94.63	89.80	48.28	18.28	67.59	100.80
2029	2.0	0.825	70.00	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Note:

(1) Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

GLJ Petroleum Consultants
Natural Gas and Sulphur
Price Forecast
Effective January 1, 2019

	NYMEX Henry Hub Near Month Contract		Midwest Price at Chicago	AECO/ NIT Spot	Alliance Transfer Pool Spot	Alberta Plant Gate			Saskatchewan Plant GatePlant Gate			British Columbia			
						Spot									
Year	Constant 2019 $ USD/ MMBtu	Then Current USD/ MMBtu	Then Current USD/ MMBtu	Then Current CAD/ MMBtu	Then Current CAD/ MMBtu	Constant 2019 $ CAD/ MMBtu	Then Current CAD/ MMBtu	ARP CAD/ MMBtu	Sask Energy CAD/ MMBtu	Spot CAD/ MMBtu	Sumas Spot USD/ MMBtu	Westcoast Station 2 CAD/ MMBtu	Spot Plant Gate CAD/ MMBtu	Sulphur FOB Vancouver USD/lt	Alberta Sulphur at Plant Gate CAD/lt
2019	3.00	3.00	2.90	1.85	2.47	1.64	1.64	1.64	1.74	1.95	2.73	1.52	1.32	130.00	123.33
2020	3.09	3.15	3.05	2.29	2.29	2.03	2.07	2.07	2.17	2.19	2.70	2.04	1.83	132.60	122.21
2021	3.22	3.35	3.25	2.67	2.67	2.35	2.44	2.44	2.54	2.57	2.90	2.42	2.21	135.25	121.20
2022	3.30	3.50	3.40	2.90	2.90	2.51	2.66	2.66	2.76	2.80	3.05	2.65	2.43	137.96	120.32
2023	3.35	3.63	3.53	3.14	3.14	2.69	2.91	2.91	3.01	3.04	3.18	2.94	2.73	140.72	121.61
2024	3.35	3.70	3.60	3.23	3.23	2.71	2.99	2.99	3.09	3.13	3.25	3.13	2.91	143.53	123.98
2025	3.35	3.77	3.67	3.34	3.34	2.75	3.10	3.10	3.20	3.24	3.32	3.24	3.02	146.40	127.45
2026	3.35	3.85	3.75	3.41	3.41	2.76	3.17	3.17	3.27	3.31	3.40	3.31	3.09	149.32	130.99
2027	3.35	3.93	3.83	3.48	3.48	2.76	3.24	3.24	3.34	3.38	3.48	3.38	3.16	152.31	134.62
2028	3.35	4.00	3.90	3.54	3.54	2.76	3.30	3.30	3.40	3.44	3.55	3.44	3.22	152.31	134.62
2029+	3.35	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.76	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Notes:

(1) Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.

(2) The plant gate price represents the price before raw gathering and processing charges are deducted.

GLJ Petroleum Consultants
International
Price Forecast
Effective January 1, 2019

					NYMEX WTI Near Month Contract Crude Oil at Cushing, OK		Light Louisiana Sweet Crude Oil		Maya Crude Oil		Brent Blend Crude Oil FOB North Sea		NYMEX Henry Hub Near Month Contract		National Balancing Point (UK)	
Year	**Inflation %**	**CADUSD Exchange Rate USD/CAD**	**GBPUSD Exchange Rate USD/GBP**	**EURUSD Exchange Rate USD/EUR**	**Then Current USD/bbl**	**Then Current CAD/bbl**	**Then Current USD/bbl**	**Then Current CAD/bbl**	**Then Current USD/bbl**	**Then Current CAD/bbl**	**Then Current USD/bbl**	**Then Current CAD/bbl**	**Then Current USD/MMBtu**	**Then Current CAD/MMBtu**	**Then Current USD/MMBtu**	**Then Current CAD/MMBtu**
2019	0.0	0.750	1.275	1.140	56.25	75.00	61.75	82.33	55.03	73.37	63.25	84.33	3.00	4.00	8.10	10.80
2020	2.0	0.770	1.300	1.150	63.00	81.82	67.00	87.01	59.60	77.40	68.50	88.96	3.15	4.09	7.90	10.26
2021	2.0	0.790	1.300	1.150	67.00	84.81	71.00	89.87	61.99	78.47	71.25	90.19	3.35	4.24	7.75	9.81
2022	2.0	0.810	1.300	1.150	70.00	86.42	74.00	91.36	63.51	78.41	73.00	90.12	3.50	4.32	7.60	9.38
2023	2.0	0.820	1.300	1.150	72.50	88.41	76.50	93.29	65.68	80.10	75.50	92.07	3.63	4.43	7.60	9.27
2024	2.0	0.825	1.300	1.150	75.00	90.91	79.00	95.76	67.86	82.25	78.00	94.55	3.70	4.48	7.60	9.21
2025	2.0	0.825	1.300	1.150	77.50	93.94	81.50	98.79	70.03	84.89	80.50	97.58	3.77	4.57	7.60	9.21
2026	2.0	0.825	1.300	1.150	80.41	97.47	84.41	102.32	72.57	87.96	83.41	101.10	3.85	4.67	7.75	9.39
2027	2.0	0.825	1.300	1.150	82.02	99.42	86.02	104.27	73.97	89.66	85.02	103.05	3.93	4.76	7.90	9.58
2028	2.0	0.825	1.300	1.150	83.66	101.41	87.66	106.25	75.39	91.39	86.66	105.04	4.00	4.85	7.90	9.58
2029+	2.0	0.825	1.300	1.150	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Note:

(1) Historical futures contract price is an average of the daily settlement price of the near month contract over the calendar month.

GLJ Petroleum Consultants
International
Price Forecast
Effective January 1, 2019

	US Natural Gas Liquids (Then Current Dollars)								US Natural Gas (Then Current Dollars)	
	Conway				Mont Belvieu					
Year	80%-20% E/P Mix USD/bbl	Propane USD/bbl	Butane USD/bbl	Condensate USD/bbl	Ethane USD/bbl	Propane USD/bbl	Butane USD/bbl	Condensate USD/bbl	Rockies Natural Gas USD/MMBtu	Algonquin City-Gates Natural Gas USD/MMBtu
2019	7.50	29.25	36.56	52.31	10.50	33.75	39.38	54.56	2.70	4.40
2020	7.88	32.76	40.95	58.59	11.03	37.80	44.10	61.11	2.85	4.55
2021	8.38	34.84	43.55	62.31	11.72	40.20	46.90	64.99	3.05	4.55
2022	8.75	36.40	45.50	65.10	12.25	42.00	49.00	67.90	3.20	4.50
2023	9.08	37.70	47.13	67.42	12.71	43.50	50.75	70.33	3.33	4.63
2024	9.25	39.00	48.75	69.75	12.95	45.00	52.50	72.75	3.40	4.70
2025	9.42	40.30	50.38	72.08	13.19	46.50	54.25	75.17	3.47	4.77
2026	9.63	41.81	52.27	74.78	13.47	48.25	56.29	78.00	3.55	4.85
2027	9.83	42.65	53.31	76.28	13.75	49.21	57.41	79.56	3.63	4.93
2028	10.00	43.50	54.38	77.80	14.00	50.20	58.56	81.15	3.70	5.00
2029	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Note:

(1) Butane prices at Conway and Mont Belvieu represent a blended price of two thirds normal butane and one third iso-butane.

Reserves Reconciliation

The Corporation's previous reserve evaluation prior to the December 31, 2018 GLJ reserve evaluation was dated effective March 31, 2018. A reserves reconciliation outlining the change from the previous report is below.

Reconciliation of Gross Reserves by Principal Product Type – Forecast Prices and Costs

Company Total Gross

	Total Light and Medium Crude			Total Heavy Crude			Total Natural Gas			Total Natural Gas Liquids			BOE		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
March 31, 2018	5,938	3,183	9,121	19	84	103	4,091	3,060	7,151	352	302	654	6,991	4,079	11,070
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	55	18	73	204	353	557	0	0	0	0	0	0	259	371	630
Technical Revisions	-739	-487	-1,226	0	-18	-18	-2,172	-1,046	-3,217	-120	-58	-177	-1,221	-737	-1,958
Acquisitions	384	91	475	0	0	0	0	0	0	0	0	0	384	91	475
Dispositions	-20	-5	-25	0	0	0	0	0	0	0	0	0	-20	-5	-25
Economic Factors	18	4	22	0	0	0	0	0	0	0	0	0	18	4	22
Production	-308	0	-308	-4	0	-4	0	0	0	0	0	0	-312	0	-312
DECEMBER 31, 2018	5,327	2,805	8,132	219	419	638	1,919	2,014	3,933	233	244	477	6,098	3,803	9,902

Conventional Resources

	Light and Medium Crude			Heavy Crude			Natural Gas			Associated Natural Gas Liquids			BOE		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
March 31, 2018	5,938	3,183	9,121	19	84	103	2,171	1,045	3,216	119	57	177	6,438	3,499	9,937
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	55	18	73	204	353	557	0	0	0	0	0	0	259	371	630
Technical Revisions	-739	-487	-1,226	0	-18	-18	-2,171	-1,045	-3,216	-119	-57	-177	-1,221	-737	-1,957
Acquisitions	384	91	475	0	0	0	0	0	0	0	0	0	384	91	475
Dispositions	-20	-5	-25	0	0	0	0	0	0	0	0	0	-20	-5	-25
Economic Factors	18	4	22	0	0	0	0	0	0	0	0	0	18	4	22
Production	-308	0	-308	-4	0	-4	0	0	0	0	0	0	-312	0	-312
DECEMBER 31, 2018	5,327	2,805	8,132	219	419	638	0	0	0	0	0	0	5,546	3,224	8,770

Shale & Tight Reservoirs

	Tight Oil			Tight Oil Solution Gas			Shale Gas			Associated Natural Gas Liquids			BOE		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
March 31, 2018	0	0	0	0	0	0	1,920	2,015	3,935	233	244	477	553	580	1,133
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	-1	0	-1	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DECEMBER 31, 2018	0	0	0	0	0	0	1,919	2,014	3,933	233	244	477	552	580	1,132

Notes:

(1) The above change categories correspond to standards set out in the COGE Handbook. Reserve additions for Infill Drilling, Extensions and Improved Recovery are combined and reported as "Extensions and Improved Recovery".

(2) Reserves reconciliation has been prepared for the period of March 31, 2018 to December 31, 2018.

Reconciliation of Gross Reserves by Principal Product Type – Forecast Prices and Costs

Company Total Gross

FACTORS	Total Light and Medium Crude			Total Heavy Crude			Total Natural Gas			Total Natural Gas Liquids			BOE		
	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
February 28, 2017	6,356	3,323	9,679	0	0	0	44,617	24,574	69,191	2,241	1,166	3,407	16,033	8,585	24,618
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	569	251	819	19	84	103	1,920	2,015	3,935	233	244	477	1140	915	2,055
Technical Revisions	-54	-209	-263	0	0	0	-489	-1,056	-1,545	-19	-58	-77	-155	-443	-598
Acquisitions	31	10	41	0	0	0	0	0	0	0	0	0	31	10	41
Dispositions	-452	-152	-604	0	0	0	-41,321	-22,445	-63,766	-2,061	-1,050	-3,111	-9,400	-4,943	-14,343
Economic Factors	-53	-39	-92	0	0	0	-24	-28	-52	-1	0	-1	-58	-44	-102
Production	-459	0	-459	0	0	0	-613	0	-613	-40	0	-40	-601	0	-601
March 31, 2018	5,938	3,183	9,121	19	84	103	4,091	3,060	7,151	352	302	654	6,991	4,079	11,070

Conventional Reservoirs

FACTORS	Light and Medium Crude			Heavy Crude			Natural Gas			Associated Natural Gas Liquids			BOE		
	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
February 28, 2017	6,356	3,323	9,679	0	0	0	44,617	24,574	69,191	2,241	1,166	3,407	16,033	8,585	24,618
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	569	251	819	19	84	103	0	0	0	0	0	0	588	335	922
Technical Revisions	-54	-209	-263	0	0	0	-489	-1,056	-1,545	-19	-58	-77	-155	-443	-598
Acquisitions	31	10	41	0	0	0	0	0	0	0	0	0	31	10	41
Dispositions	-452	-152	-604	0	0	0	-41,321	-22,445	-63,766	-2,061	-1,050	-3,111	-9,400	-4,943	-14,343
Economic Factors	-53	-39	-92	0	0	0	-24	-28	-52	-1	0	-1	-58	-44	-102
Production	-459	0	-459	0	0	0	-613	0	-613	-40	0	-40	-601	0	-601
March 31, 2018	5,938	3,183	9,121	19	84	103	2,171	1,045	3,216	119	57	177	6,438	3,499	9,937

Shale & Tight Reservoirs

FACTORS	Tight Oil			Tight Oil Solution Gas			Shale Gas			Associated Natural Gas Liquids			BOE		
	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
February 28, 2017	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Extensions and Improved Recovery	0	0	0	0	0	0	1,920	2,015	3,935	233	244	477	553	580	1,133
Technical Revisions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
March 31, 2018	0	0	0	0	0	0	1,920	2,015	3,935	233	244	477	553	580	1,133

Note:

(1) The above change categories correspond to standards set out in the COGE Handbook. Reserve additions for Infill Drilling, Extensions and Improved Recovery are combined and reported as "Extensions and Improved Recovery".

Undeveloped Reserves

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty to be recoverable where significant expenditure is required to render them capable of production. Probable undeveloped reserves are those additional reserves that are less certain to be recovered than proved reserves where significant expenditure is required to render them capable of production. The GLJ Report contains proved and probable undeveloped reserves that have been estimated in accordance with the procedures and standards contained in the COGE Handbook. All of the undeveloped reserves are currently scheduled to be developed by the Corporation within the next five years.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to the Assets at December 31, 2018, based on forecast prices and costs.

Proved Undeveloped Reserves Attributed in Current Year

Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
Attributed This Year*	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total
186	551	133	133	0	0	233	233

Shale Gas (MMcf)		BOE (Mboe)	
Attributed This Year	Current Total	Attributed This Year	Current Total
1,919	1,919	871	1,236

Probable Undeveloped Reserves Attributed in Current Year

Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)	
Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total	Attributed This Year	Current Total
216	880	376	376	0	0	244	244

Shale Gas (MMcf)		BOE (Mboe)	
Attributed This Year	Current Total	Attributed This Year	Current Total
2,014	2,014	1,171	1,835

Note:

(1) Refers to reserves first attributed in this fiscal year ending on the effective date.

It is anticipated that most of the proved undeveloped will be developed within the next five years. Access to infrastructure, takeaway capacity & market conditions could be factors preventing the Corporation from developing this reserve category within the next two years.

It is anticipated that most of the probable undeveloped reserves will be developed within the next five years. Similar to the proved undeveloped reserves, infrastructure, takeaway capacity & market conditions could be factors preventing the Corporation from developing probable undeveloped reserves within the next two years. In general, once proved and/or probable undeveloped reserves are identified, they are scheduled into the Corporation's development plans. Normally, the Corporation plans to develop its current proved and probable undeveloped reserves within five years. A number of factors that could result in delayed or cancelled development are as follows: changing economic conditions (due to pricing, operating and capital expenditure fluctuations); changing technical conditions (production anomalies such as water breakthrough or accelerated depletion); multi-zone developments (delay of a prospective formation completion until the initial completion is no longer economic); a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and surface access issues (landowners, weather conditions and/or regulatory approvals). See "*Risk Factors*" and "*Industry Conditions*".

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative.

Degradation in future commodity price forecasts relative to the forecast in the GLJ Report would also have a negative impact on the economics and timing of the development of undeveloped reserves, unless significant reduction in the future costs of development are realized.

Other than as discussed above and the various risks and uncertainties that participants in the oil and natural gas industry are exposed to generally, the Corporation is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed in this Annual Information Form. See "*Risk Factors*" and "*Industry Conditions*".

GLJ's forecast of well abandonment and reclamation costs for all wells with reserves assigned are included in their report and therefore in their estimate of future net revenue. Specifically, provisions for the abandonment and reclamation of all of the Corporation's existing and future wells to which reserves have been attributed have been included based on regional values sourced from the AER for purposes of calculating GLJ's estimate of future net revenue, all other abandonment and reclamation costs were not included.

The following table sets forth information respecting future abandonment and reclamation costs recognized in our audited consolidated financial statements for the year ended December 31, 2018 for surface leases, wells, facilities and pipelines for properties to which reserves have been attributed.

Year	**Abandonment and Reclamation Costs (Undiscounted) (M$)**	**Abandonment and Reclamation Costs (Discounted at 10%) (M$)**
Total as at December 31, 2018	**45,547**	**6,981**
Anticipated to be paid in 2019	**750**	**682**
Anticipated to be paid in 2020	**750**	**620**
Anticipated to be paid in 2021	**900**	**676**

Note:

(1) Excludes abandonment and reclamation costs for properties with no attributed reserves.

For more information with respect to our reclamation and abandonment obligations for properties with no attributed reserves, see "*Statement of Reserves Data and Other Oil and Gas Information – Properties with no Attributable Reserves*" in this Annual Information Form.

Future Development Costs

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

Company Annual Capital Expenditures (M$)

	Year												Totals			
Entity Description	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Subtotal	Remainder	Total	10% Discounted
Proved Producing	0	408	156	1154	985	461	225	477	0	165	0	0	4032	0	4,032	2,639
Total Proved	12,910	12,163	572	5,041	583	461	1,360	477	0	164	0	0	33,732	0	33,732	28,598
Total Proved Plus Probable	16,570	19,248	4,422	8,861	8,814	2,230	676	342	434	170	323	0	62,089	825	62,914	50,514

Company Annual Capital Expenditures (M$)

	Year												Totals			
Entity Description	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Subtotal	Remainder	Total	10% Discounted
Proved Undeveloped																
Deer Mountain	0	1,020	0	0	0	0	0	0	0	0	0	0	1,020	0	1,020	884
Fireweed	4,500	1,568	0	0	0	0	0	0	0	0	0	0	6,068	0	6,068	5,649
House Creek	2,100	0	0	4,563	0	0	0	0	0	0	0	0	6,663	0	6,663	5,271
Jarvie	700	0	0	0	0	0	0	0	0	0	0	0	700	0	700	667
Nipisi / Marten Hills	2,100	0	0	0	0	0	0	0	0	0	0	0	2,100	0	2,100	2,002
Panny	0	3,774	0	-677	1	0	718	0	0	2	0	0	3,818	0	3,818	3,174
South Senex	0	1,836	0	0	0	0	0	0	0	0	0	0	1,836	0	1,836	1,591
Total: Proved Undeveloped	**9,400**	**8,198**	**0**	**3,886**	**1**	**0**	**718**	**0**	**0**	**2**	**0**	**0**	**22,205**	**0**	**22,205**	**19,240**
Proved Plus Probable Undeveloped																
Deer Mountain	0	1,020	0	0	0	0	0	0	0	0	0	0	1,020	0	1,020	884
Fireweed	4,500	6,158	0	0	0	0	0	0	0	0	0	0	10,657	0	10,657	9,628
House Creek	2,100	0	0	4,563	0	0	0	0	0	0	0	0	6,663	0	6,663	5,271
Jarvie	2,100	0	0	0	758	0	0	0	0	0	0	0	2,858	0	2,858	2,496
Nipisi / Marten Hills	3,500	1,428	0	0	0	0	0	0	0	0	0	0	4,928	0	4,928	4,575
Panny	0	3,774	3,849	3,820	7,215	1,932	0	0	0	4	0	0	20,596	825	21,421	15,114
South Senex	0	1,836	0	0	0	0	0	0	0	0	0	0	1,836	0	1,836	1,591
Total: Proved Plus Probable Undeveloped	**12,200**	**14,216**	**3,849**	**8,384**	**7,973**	**1,932**	**0**	**0**	**0**	**4**	**0**	**0**	**48,558**	**825**	**49,383**	**39,558**

The Corporation expects to fund the development costs of these reserves through a combination of internally generated cash flow, equity issuances and debt. There can be no guarantee that funds will be available or that the Board will allocate funding to develop all of the reserves attributed to the Corporation in the GLJ Report. Failure to develop those reserves could have a negative impact on the Corporation's future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make development of any of the properties uneconomic.

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

For a general description of the Corporation's important properties, see "*Highwood Assets*".

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest in effective as of the date of this Annual Information Form. Highwood's oil and gas properties are all located in the Western Canadian Sedimentary Basin and onshore within the Canadian provinces of British Columbia and Alberta.

Properties with no Attributable Reserves

	Well Count		Gross			Net		
	Gross	Net	Oil	Gas	Non-Producing	Oil	Gas	Non-Producing
Operated	587.00	529.47	150.00	3.00	434.00	139.75	1.76	387.96
Non-Operated	73.00	22.86	6.00	0.00	67.00	1.75	0.00	21.11
Total	**660.00**	**552.33**	**156.00**	**3.00**	**501.00**	**141.50**	**1.76**	**409.07**

The following table sets forth the gross and net hectares of unproved properties held by the Corporation as at December 31, 2018 and the maximum net area of unproved properties for which the Corporation expects the rights to explore, develop and exploit to expire during 2019. There are no material work commitments necessary to maintain these properties.

	Unproved Properties		
	Gross Hectares	Net Hectares	2019 Expiring Net Hectares
Canada	176,611	138,505	nil

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

For information with respect to the Corporation's reclamation and abandonment obligations for the properties to which reserves have been attributed, see "*Additional Information Relating to Reserves Data – Significant Factors or Uncertainties*".

The following table sets forth the Corporation's estimate of reclamation and abandonment obligations for the properties to which no reserves have been attributed.

Year	Abandonment and Reclamation Costs (Undiscounted) (M$)	Abandonment and Reclamation Costs (Discounted at 10%) (M$)
2019	-	-
2020	-	-
2021	-	-
Thereafter	1,945	1,365
Total	**1,945**	**1,365**

Forward Contracts

The Corporation has no various hedging commitments in place with a Canadian Chartered Bank in order to mitigate exposure to changing commodity prices in the future. The outstanding hedge commitments at December 31, 2018 are as follows:

CAD Swaps:

Product	Notional Volume	Term	Fixed Price (CAD/bbl)	Index
Crude Oil	100bbl/day	October 1, 2019 to December 31, 2019	$ 89.09	WTI - NYMEX

USD Swaps:

Product	Notional Volume	Term	Fixed Price (USD/bbl)	Index
Crude Oil	100bbl/day	January 1, 2019 to March 31, 2019	$ 58.85	WTI - NYMEX
Crude Oil	100bbl/day	January 1, 2019 to March 31, 2019	$ 57.00	WTI - NYMEX
Crude Oil	100bbl/day	January 1, 2019 to March 31, 2019	$ 58.25	WTI - NYMEX
Crude Oil	100bbl/day	April 1, 2019 to June 30, 2019	$ 57.00	WTI - NYMEX

CAD Collars:

Product	Notional Volume	Term	Collar Cap (CAD/bbl)	Collar floor (CAD/bbl)	Index
Crude Oil	50bbl/day	July 1, 2019 to September 30, 2019	$ 87.50	$ 70.00	WTI - NYMEX
Crude Oil	100bbl/day	July 1, 2019 to December 31, 2019	$ 85.50	$ 70.00	WTI - NYMEX
Crude Oil	50bbl/day	July 1, 2019 to December 31, 2019	$ 91.80	$ 70.00	WTI - NYMEX
Crude Oil	100bbl/day	July 1, 2019 to September 30, 2019	$ 88.40	$ 70.00	WTI - NYMEX
Crude Oil	50bbl/day	October 1, 2019 to December 31, 2019	$ 91.75	$ 70.00	WTI - NYMEX
Crude Oil	100bbl/day	October 1, 2019 to December 31, 2019	$ 69.00	$ 59.00	WTI - NYMEX

USD Collars:

Product	Notional Volume	Term	Collar Cap (USD/bbl)	Collar floor (USD/bbl)	Index
Crude Oil	100bbl/day	January 1, 2019 to March 31, 2019	$ 55.20	$ 45.00	WTI - NYMEX
Crude Oil	100bbl/day	April 1, 2019 to June 30, 2019	$ 55.05	$ 45.00	WTI - NYMEX
Crude Oil	100bbl/day	April 1, 2019 to June 30, 2019	$ 60.32	$ 55.00	WTI - NYMEX
Crude Oil	100bbl/day	April 1, 2019 to June 30, 2019	$ 66.00	$ 55.00	WTI - NYMEX
Crude Oil	100bbl/day	July 1, 2019 to September 30, 2019	$ 63.10	$ 55.00	WTI - NYMEX

Differential:

Product	Notional Volume	Term	Fixed Price Differential (USD/bbl)	Index
Crude Oil	50bbl/day	January 1, 2019 to December 31, 2019	$ (13.50)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50bbl/day	January 1, 2019 to December 31, 2019	$ (13.35)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50bbl/day	February 1, 2019 to December 31, 2019	$ (12.50)	Edmonton Light vs. WTI - NYMEX
Crude Oil	50bbl/day	January 1, 2019 to December 31, 2019	$ (21.00)	WCS vs. WTI - NYMEX

Tax Horizon

The Corporation anticipates that income taxes are payable by the Corporation in 2019 in the proved producing category due to current tax pools.

Costs Incurred & Development Activity

The Corporation incurred $2,881,197 of development costs during the year ended December 31, 2018. The majority of the capital activity related to recompletion and fracs of existing wellbores to increase production.

During the year ended December 31, 2018, the Corporation incurred costs of $10,769,098 relating to several oil well recompletions, drilling two oil wells (1.5 net) in Red Earth, Alberta and drilling four oil wells (2 net) in Clearwater, Alberta. The Corporation also spent $7,417,382 after closing adjustments to acquire a 100% working interest in the Wabasca River Pipeline (see "*Highwood Assets*") and $1,171,297 after closing adjustments to acquire oil properties in the Corporation's core Red Earth area.

Two gross (1 net) of the Clearwater oil wells drilled were exploratory wells due to their "New Pool Wildcat" lahee classification. Two gross (1 net) of the Clearwater oil wells drilled were developmental wells. Two gross (1.5 net) of the Red Earth oil wells drilled were developmental wells. No wells drilled during in 2018 were dry holes.

See "*Highwood Assets*" and "*Description of the Business*" for a description of the Corporation's exploration and development plans.

Production Estimates

The following table sets out the volumes of working interest production before royalties, using forecast prices and costs, estimated for the period of January 1, 2019 to December 31, 2019, as evaluated by GLJ which is reflected in the estimate of future net revenue disclosed in the tables above.

Summary of First Year Production

	2019 Average Daily Production									
	Light and Medium Oil		Heavy Oil		Shale Natural Gas		Natural Gas Liquids		Oil Equivalent	
Entity Description	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d	Company Gross Mcf/d	Company Net Mcf/d	Company Gross bbl/d	Company Net bbl/d	Company Gross bbl/d	Company Net bbl/d
Proved Producing										
Conventional										
Panny	520	439	0	0	0	0	0	0	520	439
Others	722	653	129	118	0	0	0	0	851	771
Total: Conventional	1,242	1,093	129	118	0	0	0	0	1,371	1,210
Non-conventional										
Others	0	0	0	0	0	0	0	0	0	0
Total: Non-conventional	0	0	0	0	0	0	0	0	0	0
Total: Proved Producing	**1,242**	**1,093**	**129**	**118**	**0**	**0**	**0**	**0**	**1,371**	**1,210**
Proved Developed Non-Producing										
Conventional										
Panny	74	68	0	0	0	0	0	0	74	68
Others	121	113	0	0	0	0	0	0	121	113
Total: Conventional	195	181	0	0	0	0	0	0	195	181
Non-conventional										
Others	0	0	0	0	0	0	0	0	0	0
Total: Non-conventional	0	0	0	0	0	0	0	0	0	0
Total: Proved Developed Non-Producing	**195**	**181**	**0**	**0**	**0**	**0**	**0**	**0**	**195**	**181**
Proved Undeveloped										
Conventional										
Panny	0	0	0	0	0	0	0	0	0	0
Others	57	54	75	68	0	0	0	0	132	122
Total: Conventional	57	54	75	68	0	0	0	0	132	122
Non-conventional										
Others	0	0	0	0	192	190	23	21	55	52
Total: Non-conventional	0	0	0	0	192	190	23	21	55	52
Total: Proved Undeveloped	**57**	**54**	**75**	**68**	**192**	**190**	**23**	**21**	**187**	**174**

Entity Description	2019 Average Daily Production Light and Medium Oil Company Gross bbl/d	Light and Medium Oil Company Net bbl/d	Heavy Oil Company Gross bbl/d	Heavy Oil Company Net bbl/d	Shale Natural Gas Company Gross Mcf/d	Shale Natural Gas Company Net Mcf/d	Natural Gas Liquids Company Gross bbl/d	Natural Gas Liquids Company Net bbl/d	Oil Equivalent Company Gross bbl/d	Oil Equivalent Company Net bbl/d
Total Proved										
Conventional										
Panny	594	508	0	0	0	0	0	0	594	508
Others	900	820	204	186	0	0	0	0	1,104	1,006
Total: Conventional	1,494	1,328	204	186	0	0	0	0	1,698	1,514
Non-conventional										
Others	0	0	0	0	192	190	23	21	55	52
Total: Non-conventional	0	0	0	0	192	190	23	21	55	52
Total: Total Proved	**1,494**	**1,328**	**204**	**186**	**192**	**190**	**23**	**21**	**1,754**	**1,566**
Total Probable										
Conventional										
Panny	37	31	0	0	0	0	0	0	37	31
Others	39	35	90	81	0	0	0	0	128	116
Total: Conventional	76	66	90	81	0	0	0	0	165	147
Non-conventional										
Others	0	0	0	0	43	43	5	5	12	12
Total: Non-conventional	0	0	0	0	43	43	5	5	12	12
Total: Total Probable	**76**	**66**	**90**	**81**	**43**	**43**	**5**	**5**	**178**	**159**
Total Proved Plus Probable										
Conventional										
Panny	631	539	0	0	0	0	0	0	631	539
Others	939	855	294	267	0	0	0	0	1232	1,122
Total: Conventional	1,570	1,394	294	267	0	0	0	0	1,864	1,661
Non-conventional										
Others	0	0	0	0	235	233	28	25	68	64
Total: Non-conventional	0	0	0	0	235	233	28	25	68	64
Total: Total Proved Plus Probable	**1,570**	**1,394**	**294**	**267**	**235**	**233**	**28**	**25**	**1,931**	**1,725**

Production History

The following table summarizes the Corporation's share of the average gross daily production volumes, before deduction of royalties, for the financial year December 31, 2018.

Production History – Highwood's Share of Average Gross Daily Production Volumes

Daily average volume	Quarter ended March 31, 2018	Quarter ended June 30, 2018	Quarter ended September 30, 2018	Quarter ended December 31, 2018
Light & Medium Crude Oil (bbl/d)	1,087	1,242	1,033	1,117
Natural Gas (Mcf/d)	38	52	16	12
Natural Gas Liquids (boe/d)	0	1	0	0
Oil Equivalent (Boe/d)	**1,094**	**1,252**	**1,036**	**1,119**

The following table sets forth, by product type, the average gross daily production of the Corporation before deduction of royalties, the prices received, royalties paid, production costs incurred and the resulting netback on a per unit volume basis, quarterly, for the years ended December 31, 2017 and December 31, 2018. Over 99% of Highwood's current product revenues are derived from light Crude Oil sales, the netback history of which is below:

Production History – Average per Unit of Volume Results

Crude Oil ($/Bbl)	Quarter ended March 31, 2018	Quarter ended June 30, 2018	Quarter ended September 30, 2018	Quarter ended December 31, 2018
Average sales price	$64.59	$71.24	$77.15	$30.27
Royalties	$(10.33)	$(12.24)	$(12.53)	$(5.21)
Production and operating expenses [(1)]	$(57.43)	$(37.41)	$(53.34)	$(28.41)
Operating netback	**$(3.17)**	**$21.59**	**$11.28**	**$(3.35)**

Note:

(1) Production and operating expenses have been shown net of transportation expenses.

The following table sets forth the production volumes for the year ended December 31, 2018 by product type for the Assets. There were three fields that comprised more than 10 percent of the total production on a BOE basis.

Production History - by Field, for Each Product Type

	Light & Medium Crude Oil (Bbl)	Conventional Natural Gas (Mcf)	Shale Gas (Mcf)	Natural Gas Liquids (Bbl)	Oil Equivalent (Boe)
Panny (Red Earth)	160,630	-	-	-	160,630
House Creek (Red Earth)	73,678	-	-	-	73,678
South Senex (Red Earth)	70,719	-	-	-	70,719
Other Fields	103,733	10,828	-	146	105,683
Total	**408,760**	**10,828**	**-**	**146**	**410,710**

DIVIDEND RECORD AND POLICY

Highwood does not currently intend to declare future cash dividends. The amount of future cash dividends, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time-to-time, including fluctuations in commodity prices, the preference of Highwood's preferred shares, production levels, capital expenditures, compliance with covenants contained in its credit facilities from time to time, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends.

In December 2016, Predecessor Highwood made a dividend payment of $0.23 per Predecessor Highwood Share.

In December 2017, Predecessor Highwood made a dividend payment of $0.14 per Predecessor Highwood Share.

DESCRIPTION OF SHARE CAPITAL

The following is a description of the rights, privileges, restrictions and conditions attaching to Highwood's share capital.

Authorized Shares

Highwood is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares, issuable in series, without nominal or par value, of which, as at the date hereof, 6,013,965 Common Shares are issued and outstanding as fully paid and non-assessable and nil preferred shares are issued and outstanding.

Common Shares

The holders of Common Shares shall be entitled, subject to the rights, privileges, restrictions and conditions attached to any preferred shares, to dividends if, as and when declared by the directors, to one vote per share at meetings of the holders of Common Shares and, subject to the rights, privileges, restrictions and conditions attached to any preferred shares, upon liquidation, to receive such assets of Highwood as are distributable to the holders of the Common Shares.

Preferred Shares

Highwood is also authorized to issue an unlimited number of preferred shares without nominal or par value, of which, as at the date hereof, none have been issued. The preferred shares may be issued in one or more series, and the directors are authorized to fix the number of shares in each series, and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series. The preferred shares are entitled to a priority over the Common Shares with respect to the payment of dividends and the distribution of assets upon the liquidation of Highwood.

TRADING PRICE AND VOLUME

The Common Shares are listed for trading on the TSX Venture Exchange under the symbol "HOCL". The following table sets forth the price range (high and low closing prices) and trading volume of our Common Shares on the TSX Venture Exchange for the periods indicated:

Period	High ($)	Low ($)	Volume
2018			
April 6-30[(1)]	0.28	0.18	331,200
May	0.25	0.18	135,431
June	0.22	0.17	175,300
July	0.20	0.15	124,500
August	0.17	0.13	152,381
September	0.20	0.20	17,000
October	0.17	0.10	70,800
November[(2)]	N/A	N/A	N/A
December	N/A	N/A	N/A
2019			
January 29-31[(3)]	11.00	9.00	8,690
February	30.00	9.00	58,003
March	22.50	13.00	12,361
April	26.00	22.50	5,731

Period	High ($)	Low ($)	Volume
May 1 - 21	25.00	24.50	2,945

Notes:

(1) On April 3, 2018, PBC completed its initial public offering and the PBC Shares began trading under the symbol "PRED.P" as a CPC on April 6, 2018.

(2) The PBC Shares were halted on November 2, 2018 at the request of PBC for the Amalgamation.

(3) Common Shares began trading on January 29, 2019 under the symbol "HOCL" following completion of the Amalgamation.

PRIOR SALES

The following table summarizes the issuances of unlisted securities for the year ended December 31, 2018:

Date of Issuance	Securities	Number of Common Shares Issued/Issuable or Aggregate Amount	Price/Exercise Price per Security ($)
April 3, 2018	Options(1)	7,547	5.30
April 3, 2018	Options(2)	18,868	5.30

Notes:

(1) PBC Share purchase options issued to agents, each such option being previously exercisable into one PBC Share, which was exchanged pursuant to the Amalgamation for one an option exerciseable into one Common Share.

(2) PBC Share purchase options issued to PBC founders, each such option being previously exercisable into one PBC Share, which was exchanged pursuant to the Amalgamation for one an option exerciseable into one Common Share.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

The following table summarizes Highwood's securities that remained in escrow or subject to restrictions on transfer as at the date hereof:

Designation of Class	Number of securities held in escrow or that are subject to a contractual restriction on transfer	Percentage of Class(1)
Common Shares (2)	4,609,915	76.65%
Common Shares (3)	25,030	0.42%
Common Shares (4)	65,935	1.10%
Total	**4,700,880**	**78.17%**

Notes:

(1) Percentages based on 6,013,965 Common Shares issued and outstanding as of the date hereof.

(2) On January 23, 2019, the Amalgamation was completed pursuant to which PBC and Highwood continued the business of Highwood. This transaction qualified as PBC's Qualifying Transaction. As part of the Amalgamation, 4,530,670 Common Shares were deposited in escrow with Odyssey Trust Company. Upon the issuance by the TSXV of their final bulletin on January 28, 2019, approving the Amalgamation and other elements of PBC's Qualifying Transaction, 10% of such Common Shares were released from escrow, with an additional 15% authorized of each such securities to be released on the dates that are 6, 12, 18, 24, 30 and 36 months following January 28, 2019.

(3) In accordance with the TSX Venture Exchange's Seed Share Resale Restrictions, 25,030 Common Shares issued to Non-Principals are legended in accordance with a Tier 2 Value Security Escrow Agreement release schedule to be released over a 36-month period. Upon the issuance by the TSXV of their final bulletin on January 28, 2019, approving the Amalgamation and other elements of PBC's Qualifying Transaction, 10% of such Common Shares were no longer subject to transfer restrictions, with an additional 15% authorized of each such securities to be released on the dates that are 6, 12, 18, 24, 30 and 36 months following January 28, 2019.

(4) On April 29, 2019, the Corporation completed the Saskatchewan Acquisition. A portion of the purchase price consisted of the issuance of 65,935 Common Shares, of which 32,967 Common Shares (being 50% thereof) are subject to a contractual 90 day hold period from the date of closing and the remaining 32,968 Common Shares (being 50% thereof) are subject to a contractual 180 day hold period from the closing date. See "*General Development of the Business – Recent Devlopments*".

DIRECTORS AND OFFICERS

Summary Information

The name, province and country of residence, positions held, period during which such positions has been held and principal occupation of each director of Highwood during the past five years are set out below.

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Common Share Ownership[(1)]
Stephen J. Holyoake [(2)(3)(4)] *Alberta, Canada*	Director	President and Chief Executive Officer of Fireweed Energy Ltd. since February 2017. Director of Predator Oil BC Ltd. from February 2017 to June 2018. Director of Tidewater Midstream & Infrastructure Ltd. since April 2016. Director of Fireweed Energy Ltd. since January 2016. Prior thereto, Vice President, Drilling and Completions of Tangle Creek Energy Ltd. from May, 2012 to February, 2017. Prior thereto, Vice President, Operations of SkyWest Energy Corp. from May 2010 to December 2011.	October 10, 2012	149,587 (2.49%)
Trevor Wong-Chor [(2)(3)(4)] *Alberta, Canada*	Director	Partner with DLA Piper (Canada) LLP (and its predecessor firms) since September, 2004. Prior thereto, Partner and Associate at Borden Ladner Gervais LLP (and its predecessor firms) from 1998 to 2004.	January 23, 2019	3,774 (0.33%)
Arif Shivji [(2)(3)(4)] *Alberta, Canada*	Director	President & CEO of Hoist Capital Corp. since July 2018. President, CEO and CFO of Predator Blockchain Capital Corp. from February 2018 to January 2019. CFO of Highwood from 2012 to 2014 and CFO Predator Midstream from 2012 to 2014.	January 23, 2019	60,377 (1.00%)
Greg Macdonald *Alberta, Canada*	President, CEO & Director	President, CEO & Director of Highwood since June 15, 2017 and President & COO of Highwood since May 11, 2015. Prior thereto, VP, Engineering with Highwood from May 2014 to May 2015. VP, Engineering with Predator Midstream from May 2014 to August 2014. VP, Engineering with Tidewater Midstream & Infrastructure Ltd. from March 2015 to December 2016. Senior Area Manager, Molopo Energy Canada from August 2013 to May 2014. Greg has served as a director for Cedar Creek Energy Ltd. from December 2016 to present, Mach Energy Services Inc. from January 2015 to June 2017, Hoist Capital Corporation from September 2018 to present and Battle River Energy from June 2018 to present.	June 8, 2017	311,438 (5.18%)

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Common Share Ownership[(1)]
Graydon Glans *Alberta, Canada*	CFO & Secretary	Chief Financial Officer of Highwood since June 15, 2015. Prior thereto, Controller, PRD Canada, Secure Energy Services from August 2014 to April 2015. Manager Financial Reporting, Predator Midstream Ltd. from May 2014 until its sale in August 2014. Manager, Collins Barrow Calgary LLP from January 2013 to April 2014.	N/A	19,877 (0.33%)
Kelly McDonald *Alberta, Canada*	Vice President, Exploration	Vice President Exploration of Highwood since February 1, 2017. Prior thereto, Principal, KJ McDonald Consulting from April 2016 to February 2017 and from May 2013 to June 2014, VP, Exploration, Reserve Royalty Income Trust from October 2014 to March 2016, Geological Manager, Lighthouse Oil and Gas LP, June 2014 to October 2014.	N/A	19,000 (0.32%)

Notes:

(1) Represents Common Shares and other securities beneficially owned, controlled or directed (directly or indirectly) by the director or officer as of the date hereof based on information provided by such individuals. Percentages based on 6,013,965 Common Shares issued and outstanding as of the date hereof.

(2) Member of the Audit Committee. Arif Shivji is the Chair of the Audit Committee.

(3) Member of the Corporate Governance & Compensation Committee. Stephen J. Holyoake is the Chair of the Corporate Governance & Compensation Committee.

(4) Member of the Reserves, Safety and Environmental Committee. Stephen J. Holyoake is the Chair of the Reserves, Safety and Environmental Committee.

All of the Corporation's directors' terms of office will expire at the earliest of their resignation, the close of the next annual shareholder meeting called for the election of directors, or on such other date as they may be removed according to the ABCA.

Security Holding by Directors and Officers

As at the date hereof, the directors and executive officers, as a group, beneficially own, directly or indirectly, or exercise control or direction over, an aggregate of 564,053 Common Shares, representing approximately 9.38% of the issued and outstanding Common Shares. The information as to the number of Common Shares beneficially owned, or controlled or directed, not being within the knowledge of the Corporation, has been furnished by the respective directors and officers of the Corporation individually.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of management no director or executive officer as at the date hereof, is or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any corporation (including the Corporation), that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes hereof, "order" means: (a) a cease trade order; (b) an order similar to a cease trade order; or (c) an order that denied the relevant Company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days.

Bankruptcies

To the knowledge of management no director, executive officer of the Corporation or a Shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation (a) is, as at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any corporation (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Penalties or Sanctions

To the knowledge of management no director, executive officer or Shareholder holding a sufficient number of securities of the Corporation to materially affect the control of the Corporation (i) has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (ii) has incurred any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Trevor Wong-Chor, as Director and Secretary of the Corporation, is a Partner with DLA Piper (Canada) LLP, which provides legal services to the Corporation on a fee for services basis.

There are potential conflicts of interest to which the directors and officers of the Corporation may be subject to in connection with the operations of the Corporation. In particular, certain directors and officers of the Corporation and its subsidiaries are associated with other reporting issuers or other corporations, including Fireweed Energy Ltd. and Tidewater Midstream & Infrastructure Ltd., which may give rise to conflicts of interest with the Corporation. See "*General Development of the Business – Three Year History*" and "*Description of the Business*", "*Interests of Management and Others in Material Transactions*", and "*Promoters*".

Highwood, as sub-tenant, and Tidewater Midstream and Infrastructure Ltd., as sub-landlord, are parties to a sub-lease agreement dated March 31, 2017 regarding Highwood's head office lease.

In accordance with the applicable corporate and securities legislation, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Certain of the directors and each of the executive officers of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors and officers of the Corporation will only be able to devote part of their time to the affairs of the Corporation. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the applicable corporate law.

Insurance Coverage and Indemnification

The Corporation maintains liability insurance for its directors and officers with coverage and terms that are customary for a Company of its size and industry. In addition, the Corporation has entered into indemnification agreements with its directors and officers. The indemnification agreements generally require that the Corporation indemnify and hold the indemnitees harmless to the greatest extent permitted by law for liabilities arising out of the indemnitees' service to the Corporation as directors and officers, so long as the indemnitees acted honestly and in good faith with a view to the best interests of the Corporation and, with respect to criminal or administrative actions or proceedings that are enforced by monetary penalty, if the indemnitee had no reasonable grounds to believe that his or her conduct was unlawful. The indemnification agreements also provide for the advancement of defence expenses to the indemnitees by the Corporation.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments where the companies have assets or operations. While these regulations do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although governmental legislation is a matter of public record, the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

Highwood currently holds interests in crude oil and natural gas properties, along with related assets in the Canadian provinces of Alberta and British Columbia. Highwood's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of Highwood's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in western Canada.

Pricing and Marketing

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macro and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Condensate and Other Natural Gas Liquids

The pricing of condensates and other natural gas liquids such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports From Canada

Crude oil, natural gas and NGLs exports from Canada are subject to the *National Energy Board Act* (Canada) (the "**NEB Act**") and the *National Energy Board Act* Part VI (Oil and Gas) Regulation (the "**Part VI Regulation**"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the "**NEB**") is required. There is no longer a public hearing requirement for the export of natural gas and NGLs. Instead, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g., NGLs), the maximum term is 25 years. In addition to NEB approval, all crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government ("**Cabinet**").

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to 20 years for quantities not exceeding 30,000 cubic metres per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the federal government.

On February 8, 2018, the Government of Canada introduced Bill C-69, draft legislation that, if enacted, will replace the NEB with the Canadian Energy Regulator ("**CER**"). The CER will take on the NEB's responsibilities with respect to the export of crude oil, natural gas and NGLs from Canada. However, it is not proposed that the legislative regime relating to exports of crude oil, natural gas and NGLs exports from Canada will substantively change under the new regime as currently drafted.

Highwood does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from western Canada to the US and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different areas and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government introduced Bill C-69 to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes will be made in the interim. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays from provincial and municipal governments, as well as court challenges related to issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of the relevant environmental review processes. Such political and legal opposition creates further uncertainty. In addition, export pipelines from Canada to the US face additional uncertainty as such pipelines require approvals of several levels of government in the US.

In the face of this regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, especially the Midwest US and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of western Canada to reach eastern Canada, the US and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from western Canada to domestic and international markets, the Enbridge Line 3 Expansion from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, experienced a construction permitting setback and is now expected to be in-service in the latter half of 2020.

The proposed Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government entered into an agreement with Kinder Morgan Cochin ULC in May 2018 to purchase the shares and units of the entities that own and operate the Trans Mountain Pipeline system. The shareholders subsequently voted to approve the transaction in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the 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, the Cabinet ordered the NEB to reconsider its recommendation in light of the Federal Court of Appeal decision, including the environmental effects of project-related marine shipping. On February 22, 2019, the NEB delivered an updated report to Cabinet, recommending that Cabinet approve the pipeline expansion, subject to 156 conditions and 16 new recommendations. While Cabinet has three months to consider the NEB's report, it may extend this deadline to accommodate a new round of indigenous consultation, upon completion of which it will decide whether to approve or deny the pipeline expansion.

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 US Federal Court Judge determined the underlying environmental review was inadequate. This decision has been appealed.

Finally, Bill C-48 continues to advance through the federal legislative process. If enacted, Bill C-48 will impose a moratorium on tanker traffic transporting certain crude oil and NGL products from British Columbia's north coast. See "*Environmental Regulation - Federal*" in these Industry Conditions.

The Government of Alberta has also sought to alleviate these transportation constraints by pursuing different transportation modalities and creating new markets. On November 28, 2018, the Government of Alberta announced that Alberta had started negotiations for investment in new rail capacity to address the historically high price differential between Western Canadian crude oil and West Texas Intermediate crude oil. On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 barrels per day of crude oil out of the province. The Alberta Petroleum Marketing Commission will purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. The Government expects the first railcars to be in service by July 2019 and believes this strategy will: (i) narrow the crude oil price gap by up to $4 per barrel; and (ii) provide junior producers with a more affordable option to move their crude oil to market.

On December 11, 2018, the Government of Alberta announced a Request for Expressions of Interest to create new refining capacity or expand existing capacity. The deadline for interested parties to submit Expressions of Interest was February 8, 2019, and an internal governmental committee is currently reviewing such submissions.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in western Canada for their natural gas, which in the last several years has generally been depressed (at times, producers have received negative pricing for their natural gas production). Repairs or upgrades required on existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules (Alberta), the Government of Alberta will, on a monthly basis, direct crude oil producers producing more than 10,000 barrels per day to curtail their production according to a pre-determined formula that apportions production limits proportionately amongst those operators subject to a curtailment order. The first curtailment order took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million barrels per day. A reduction of approximately 8.7 per cent of total daily average crude oil production in Alberta during December 2018. The Government of Alberta indicated that it expected the curtailment rate to gradually drop over the course of 2019. As a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage, the Government of Alberta announced on January 30, 2019, that it would ease the mandatory production curtailment beginning February 1, 2019, increasing the allowable production cap by 75,000 barrels per day to a maximum output of approximately 3.63 million barrels per day. Highwood is not subject to a curtailment order, as production is less than the threshold production volume.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the US and Mexico came into force on January 1, 1994. Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the US and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the US or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36-month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

On November 30, 2018, US President Trump, Prime Minister Trudeau, and outgoing Mexican President Pena Nieto signed an authorization for a new trade deal that will replace NAFTA. The "New NAFTA" is referred to as the United States-Mexico-Canada Agreement ("**USMCA**"). However, NAFTA remains the North American trade agreement currently in force until the legislative bodies of the three signatory countries ratify the USMCA. Amid political uncertainty in Canada, Mexico, and the US, it is unclear when the end of the NAFTA era will be. As the US remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, the implementation of the final ratified version of the USMCA could have an impact on western Canada's crude oil and natural gas industry at large, including the Corporation's business.

As discussed above, at the end of 2018 the Government of Alberta announced curtailment of Alberta's crude oil and bitumen production for 2019. Curtailment complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen to the other NAFTA signatories. As a result of the proportionality rule, a reduction in Canadian supply reduces the required offering under NAFTA. This may reduce the amount of Canadian crude oil and bitumen being sold at depressed prices. It is not clear whether the USMCA will come into force before the Government of Alberta's curtailment order is repealed automatically on December 31, 2019.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and 10 other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. On December 30, 2018 the CPTPP came into force among the first six countries to ratify the agreement - Canada, Australia, Japan, Mexico, New Zealand, and Singapore. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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

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

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined through negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes. Royalties from production on Crown lands are determined by government regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. The majority of Highwood's assets are on Crown lands.

Occasionally, the governments of the western Canadian provinces create incentive programs, often during periods of low commodity prices or to incent development of specific resources or specific technologies. Such programs can provide royalty rate reductions, royalty holidays or royalty tax credits to encourage exploration and development activity.

The following is a description of key royalty programs that are applicable to Highwood in the jurisdictions in which we operate. This is not meant to be a fulsome description of all royalty programs; please refer to the respective Province's websites for full royalty details.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF took effect on January 1, 2017. Wells drilled prior to January 1, 2017 continue to be governed by the prior "Alberta Royalty Framework" (the "**ARF**") for a period of 10 years, until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed five per cent royalty applies until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, the royalty rate will move to a sliding scale (based on volume and price) with a minimum gross royalty rate of five per cent. The downward adjustment of the royalty rate in the mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

<table>
<tr><th colspan="5">Alberta Royalty Regimes Summary</th></tr>
<tr><th>Royalty Regime</th><th>Product</th><th>Incentive Period</th><th>Post Incentive or Mid-Life (MRF)</th><th>Mature Phase (MRF)</th></tr>
<tr><td rowspan="3">ARF - Royalty formulas based on price and production</td><td>Oil</td><td rowspan="3">5%</td><td colspan="2">0% to 40%</td></tr>
<tr><td>Gas</td><td colspan="2">5% to 36%</td></tr>
<tr><td>Liquids - C3 & C4 / C5+</td><td colspan="2">Flat 30% / Flat 40%</td></tr>
<tr><td rowspan="3">MRF - Royalty formulas based on price with a reduction for lower production during the mature phase</td><td>Oil / Cond / C5+</td><td rowspan="3">Pre-payout 5%</td><td>10% to 40%</td><td rowspan="3">Minimum 5%</td></tr>
<tr><td>Gas</td><td>5% to 36%</td></tr>
<tr><td>C3 /C4</td><td>10% to 36%</td></tr>
</table>

British Columbia

The royalty payable on natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For gas wells, the royalty rate depends on the date of acquisition of the tenure rights and the spud date of the well. The royalties payable on natural gas liquids produced on Crown lands are levied at a flat rate of 20 per cent of the sales volume.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's natural gas wells. Important programs applicable to our key properties are:

Deep Well Royalty Credit Program, which provides a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, and is well specific based on drilling and completion depths.

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

Environmental Regulation

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, current and future changes to environmental legislation, including legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. However, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the CER. Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. It appears that additional categories of projects may be included within the new impact assessment process, such as large-scale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the public and indigenous groups prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or Cabinet; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. As to the proposed CER, many of its activities would be similar to the NEB, albeit with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g., overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016, will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The eventual effects of the proposed regulatory scheme on proponents of major projects remains unclear.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, that portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related Acts including the Oil and Gas Conservation Act (the "**OGCA**"), the Oil Sands Conservation Act, the Pipeline Act, and the Environmental Protection and Enhancement Act. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

The Ministry of Indigenous Relations (the "**MIR**") began a renewal process for the Government of Alberta's Policy on Consultation with First Nations on Land and Natural Resource Management, 2013 and the Government of Alberta's Policy on Consultation with Metis Settlements on Land and Natural Resource Management, 2015. In 2018, the Ministry updated the Joint Operating Procedures for Consultation on Energy Resource activities ("**JOP**") and associated guidelines. The JOPs and Guide were updated to clarify roles and responsibilities, internal procedures and expectation for information sharing. As a result of the update, industry can make applications to the AER (PLA, MSL, LOC) for a Crown Disposition concurrently with application to the Aboriginal Consultation Office.

British Columbia

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

The British Columbia Government recently passed Bill 51 - 2018: *Environmental Assessment Act,* which replaces the environmental assessment regime that has been in place since 2002. The Government expects that the updated Environmental Assessment Act will enter into force in late 2019. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process, as well as enhance indigenous engagement in the project approval process with an emphasis on consensus-building.

On July 16, 2018, the BCOGC issued Bulletin 2018-15, outlining critical areas in Blueberry River First Nation ("**BRFN**") traditional territory where new surface disturbance will not be permitted or will be restricted and other areas where development activities will be managed. The Interim Measures arose out of the Regional Strategic Environmental Assessment ("**RSEA**") which is being done collaboratively with BRFN's and other Treaty 8 Nations. The Interim Measures provide some additional protections to a small subset of BRFN territory of critical community interest. Highwood has no tenure or activities in the area outlined in the bulletin and access through the designated area, should not be required for marketing and sales of future production from Highwood's Doig property.

Liability Management Rating Program

The provinces of Alberta and British Columbia have each implemented similar liability management programs in respect to upstream oil and gas wells, facilities and pipelines. These programs are designed to assess a licensee's ability to address its suspension, abandonment, remediation and reclamation liabilities. A licensee whose deemed liabilities exceed its deemed assets within the jurisdiction are required to provide a security deposit.

Alberta

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). At its core, the AER uses the AB LMR Program to aid in determining the ability of licensees to manage the abandonment and reclamation obligations associated with the licensee's assets. If a licensee whose deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licenses. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). The AER assesses the LMR of all licensees on a monthly basis and posts the ratings on the AER's public website. Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant ("**WIP**") becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In '*Orphan Well Association v Grant Thornton Limited*', the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the provincial OGCA, including the AB LLR Program, and the federal *Bankruptcy and Insolvency Act* (the "**BIA**"). This ruling meant that receivers and trustees of insolvent entities have the right to renounce assets within insolvency proceedings, and was affirmed by a majority of the Alberta Court of Appeal. On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in 'Orphan Well Association v Grant Thornton Limited', the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs pending a final decision from the Supreme Court of Canada. The AER amended its licensing and liability management programs pending a final decision from the Supreme Court of Canada. The AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licence eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. While the Supreme Court of Canada's 'Orphan Well Association v Grant Thornton Limited' decision alleviates some of the concerns that the AER's rule changes were intended to address, it is unclear how or if the AER will respond.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20 per cent of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76 per cent of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81 per cent of licensees operating in the province having met their annual quota. The IWCP completed its third year on March 31, 2018 but the AER has not yet released its third annual report.

As part of its strategy to encourage the decommissioning of inactive or marginal oil and gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations while enabling participants to meet their liability reduction targets. Highwood continues to allocate funds to abandonment and reclamation operations and is in compliance with all requirements. Highwood has applied to participate in the voluntary ABC program and anticipates feedback on acceptance in 2019.

British Columbia

Similar to Alberta, the BCOGC oversees a Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the BCOGC determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

In the spring of 2018 the Government of British Columbia passed certain amendments to the OGAA (the "**Amendments**") which when brought into force, will replace the orphan site reclamation fund tax currently paid by permit holders with a levy paid to the Orphan Site Reclamation Fund ("**OSRF**"). Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders currently make monthly payments of $0.03 per 1,000 cubic metres of marketable gas produced and $0.06 per cubic meter of petroleum produced. The Amendments will 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 fund. The Amendments permit the BCOGC to impose more than one levy in a given calendar year.

Beginning April 1, 2019, the existing orphan tax will be eliminated and replaced by a new liability levy. This new levy will ensure the Commission has adequate funds to restore all orphan sites in the province in a timely manner. The change is supported in legislation by amendments to section 47 of the Oil and Gas Activities Act authorized by Bill 15 in 2018. The liability levy will be phased in over three years. The 2019/20 fiscal year will see 50 per cent of orphan funding come from the new liability levy, increasing by 25 per cent in each subsequent year. The remaining funding in these years will come from the Commission's operating production levy. By 2021/22, the liability levy will provide 100 per cent of the annual levy required to fund restoration treatment of orphan sites.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulation of the crude oil and natural gas industry in Canada.

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

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of January 1, 2019, 184 of the 197 parties to the convention have ratified the Paris Agreement. In December 2018, the United Nations annual Conference of the Parties took place in Katowice, Poland. The Conference concluded with the attendees reiterating their commitment to the targets set out in the Paris Agreements and established a transparency framework related to, among other matters, emissions and climate finance reporting.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30 per cent from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10 per tonne, increasing annually until it reaches $50 per tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. Seven provinces and territories have introduced carbon-pricing systems in place that would meet federal requirements (Alberta, British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories). The federal carbon-pricing regime will take effect in Saskatchewan, Manitoba, Ontario, New Brunswick in April 2019; it will take effect in the Yukon, and Nunavut in July 2019. Saskatchewan and Ontario have challenged the constitutionality of the federal government's pricing regime; New Brunswick has intervened in Saskatchewan's constitutional challenge. In October 2018, the federal government announced an alternative pricing scheme for large electricity generators designed to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation rates.

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, but will not come into force until January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane 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 about 20 megatonnes by 2030.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The Climate Leadership Act came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. While the levy is anticipated to increase again in 2021 in line with the federal legislation, the Government of Alberta has announced it will not proceed with the scheduled 2021 increase unless the expansion to the Trans Mountain Pipeline proceeds. On December 14, 2016, the Oil Sands Emissions Limit Act came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

The Carbon Competitiveness Incentives Regulation (the "**CCIR**"), which replaces the Specified Gas Emitters Regulation, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50 per cent and 25 per cent for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of one per cent, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

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

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80 per cent below 2007 levels by 2050. Additionally, British Columbia seeks to generate at least 93 per cent of its electricity from clean or renewable sources and build the infrastructure necessary to transmit it. The legislation established no date for this target.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30 per tonne. However, in its September update to the 2017/2018 Budget, the Government signalled raising the carbon tax to $35 per tonne in April 2018.

On January 1, 2016, the *Greenhouse Gas Industrial Reporting and Control Act* (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "CleanBC", which seeks to ensure that British Columbia achieves 75 per cent of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation, construction, and waste sectors of the British Columbia economy. Key initiatives include: i) increasing the generation of electricity from clean and renewable energy sources; ii) imposing a 15 per cent renewable content requirement in natural gas by 2030; iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20 per cent by 2030; iv) investing in the electrification of crude oil and natural gas production; v) reducing 45 per cent of methane emissions associated with natural gas production; and vi) incentivizing the adoption of zero-emissions vehicles. On January 16, 2019, the BCOGC announced a series of amendments to the British Columbia 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 will come into effect on January 1, 2020.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over Cdn$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of the Corporation. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form.

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

The risk factors set forth in this Annual Information Form relating to the oil and natural gas business, environmental and the operations and reserves of the Corporation apply equally in respect of the Corporation. In particular, the reserve information contained in the GLJ Report in respect of the Corporation are only an estimate and the actual production from and ultimate reserves of those properties may be greater or less than the estimate contained in such reports. See "*General Development of the Business – Three Year History*" and "*Description of the Business*".

Nature of Business

An investment in Highwood should be considered highly speculative due to the nature of the Corporation's involvement in the exploration for, and the acquisition, production and marketing of, oil and natural gas reserves and its current stage of development. Oil and gas operations involve many risks, which even a combination of experience, knowledge, and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Highwood.

Red Earth Caribou Protection

The Alberta Government Environment and Parks division has restricted surface mineral dispositions in northern sections of the province with a view to reduce the industrial footprint and impact on Caribou. Many of the surface mineral rights in the Red Earth area which would have otherwise presented economically viable drilling locations for the Corporation will not be accessible until the Alberta government determines a course of action on the Caribou and their migration. No timetable is set for further information on when these restrictions might be lifted.

Clearwater Development Egress

The future development and economics of the Clearwater formation in the Jarvie/Nipisi/Marten Hills area will be impacted by product takeaway and pipeline egress options which become available go forward. Currently there are no binding plans for any producers or midstream entities in the area to provide a pipeline for increased egress optionality. Current production from the area is restricted to takeaway and marketing via trucking. While economical to develop at current pricing, the long-term viability and economics of the developing play will be significantly impacted by the capital deployed by the Corporation and competitors in the area. There is large uncertainty at this time what the long-term marketing structure will look like for production out of this area.

Alberta Energy Regulator 2.0 LMR Requirements

As of the date of this Annual Information Form, the Corporation's LMR ratio with the Alberta Energy Regulator was 1.36. As the Corporation is below a 2.0 threshold as mandated by the AER, the Corporation must apply for discretion with the regulator whenever they transfer wellbores, facilities and pipelines in and out of the Corporation. This discretion is subject to approval by the regulator and there is no guarantee of receiving their consent. To the date of this Annual Information Form the Corporation has not had any transactions restricted by the AER.

Current Pipeline Release Remediations

The Corporation is currently remediating three emulsion pipeline releases on a segment of pipeline which began in June 2018. As of December 31, 2018, the Corporation has recorded costs of $32,150,000 relating to the remediation and reclamation work required to maintain the sites based on Alberta Energy Regulator guidelines. The Corporation has filed an insurance claim under their current environmental insurance policies and has received proof of loss documentation from subject underwriters. The insurance adjustor assigned by the Corporation's underwriters is currently working through the claim and verifying the Corporation's expenditures. As the claim has had coverage confirmed, the Corporation has accrued $31,630,000 of spill costs receivable due from insurers at December 31, 2018. The accrual at December 31, 2018 considers the Corporation's self-insured portion of the spill of $520,000. To date, $20,000,000 of insurance proceeds have been received by the Corporation from insurance underwriters.

There is uncertainty with regards to the final response of the regulator and the Corporation's proposed remediation plan as this will impact the timing and magnitude of additional cost outlays. While the Corporation believes the expenses incurred so far constitute bona fide insurable costs under its environmental policies, there is risk that the insurers decline coverage regarding certain costs.

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil, natural gas and NGLs, affecting net production revenue, production volumes and development and exploration activities.

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

Prices for oil, natural gas and NGLs are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil, natural gas and NGLs, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of the Organization of the Petroleum Exporting Countries ("**OPEC**") and other oil and gas exporting nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil, natural gas and NGLs are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and associated NGLs and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

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

Oil, natural gas and NGLs prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil, natural gas and NGLs prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects. In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

See "*Risk Factors – Weakness in the Oil and Gas Industry*".

Weakness in the Oil and Gas Industry

Weakness and volatility in the market conditions for the oil and gas industry may affect the value of the Corporation's reserves, restrict its cash flow and its ability to access capital to fund the development of it properties.

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced and sold in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms.

Political Uncertainty

The Corporation's business may be adversely affected by recent political and social events and decisions made in the United States, Europe and elsewhere.

The Corporation's business may be adversely affected by recent political and social events and decisions made in the United States, Europe and elsewhere.

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the 2016 presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Recently, the US administration announced its withdrawal from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces US corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. The North American Free Trade Agreement has been replaced with the United States-Mexico-Canada Agreement and the practical impacts of this new treaty are uncertain at this time. The administration has also taken action with respect to reduction of regulation which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Corporation. In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and deadline for the Government of the United Kingdom to implement such withdrawal is nearing. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of its Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and gas industry including the balance between economic development and environmental policy such as the potential impact of the recent change of government in British Columbia and announcements and actions by the government of British Columbia that may impact the completion of the Trans-Mountain Pipeline project and other infrastructure projects.

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas.

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

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

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

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

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

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

Gathering and Processing Facilities and Pipeline Systems

Lack of capacity and/or regulatory constraints on gathering and processing facilities and pipeline systems may have a negative impact on the Corporation's ability to produce and sell its oil and natural gas.

The Corporation delivers its products through gathering and processing facilities and pipeline systems. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities and pipeline systems. The lack of availability of capacity in any of the gathering and processing facilities and pipeline systems could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, operations and cash flows. Announcements and actions taken by the governments of British Columbia and Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has recently introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Pipeline Systems

Pipeline interruptions or capacity constraints may have a negative impact on the Corporation's ability to transport and market its products.

The interruption of firm pipeline transportation has and may continue to affect the oil and natural gas industry and limit the ability to fully produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems may also affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators may also affect the Corporation's production, operations and financial results. The Corporation's production could be adversely impacted by both firm and interruptible transportation service curtailments on TransCanada's NGTL and Canadian Mainline systems.

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays, cost overruns and marketing challenges.

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Corporation's ability to execute projects and market oil, natural gas and NGLs depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and

- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all and may be unable to market the oil and natural gas that it produces effectively.

Reserves Estimates

The Corporation's estimated proved and proved plus probable reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil, natural gas and NGLs reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil, natural gas and NGLs;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

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

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

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

Hedging

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk.

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline, or to diversify commodity price risk to multiple markets. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines or to diversify commodity price risk, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

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

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

Credit Facility Arrangements

Failing to comply with covenants under the Corporation's credit facility could result in restricted access to capital or being required to repay all amounts owing thereunder.

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on a reserves-based lending formula. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchasing or making other distributions with respect to the Corporation's securities, incurring additional indebtedness, providing guarantees, the assumption of loans, making capital expenditures, entering into amalgamations, mergers, take-over bids or disposing of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014, and while prices have recently increased they remain volatile as a result of various factors including actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility. Further, This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

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

Unless an event of default occurred such as a covenant breach, the lender would not be able to call the term loan until the next 6-month renewal period although under the current facility the Corporation would have the option to extend the loan for 364 days at the next renewal date.

Forward-Looking Information

Forward-Looking Information May Prove Inaccurate.

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information, and in particular, the guidance provided under "*General Development of the Business*". By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumption and uncertainties are found under "*Forward-Looking Information Statements*".

Substantial Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations, acquire and develop reserves.

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

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

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

Additional Funding Requirements

The Corporation may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility.

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

As a result of global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows.

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017.

Geo-Political Risks

Global political events may adversely affect commodity prices which in turn affect the Corporation's cash flow.

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

Eco-Terrorism Risks

The Corporation's properties may be subject to terrorist attack.

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

Management of Growth

The Corporation may not be able to effectively manage the growth of its business.

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

Reliance on Key Personnel

Loss of key personnel would negatively impact the Corporation's operations.

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

Influential Shareholder

1080766 Alberta Ltd. holds approximately 67.27% of the issued and outstanding Common Shares as at the date hereof and, as such, may be able to exert influence on the Corporation through its voting rights. Furthermore, through its voting rights, 1080766 Alberta Ltd. will be able to exercise influence over the management, administration, strategy and growth of the Corporation. Joel A. MacLeod, is a shareholder, director and officer of 1080766 Alberta Ltd.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact its operations and financial position.

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

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the

Corporation's technological infrastructure or financial resources. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Market Price of Common Shares

The trading price of the Common Share may be adversely affected by factors related and unrelated to the oil and natural gas industry.

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market, including governmental regulatory actions or adverse changes in general market conditions or economic trends. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors, as well as the Corporation's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Impact of Future Financings on Market Price

The Corporation's future financings may negatively impact the market price of the Common Shares.

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

Dilution

The Corporation may issue additional Common Shares, diluting current Shareholders.

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

Competition

The Corporation competes with other oil and natural gas companies, some of which have greater financial and operational resources.

The oil and gas industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources.

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

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

Disposal of Fluids Used in Operations

Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation.

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Corporation's costs of compliance.

Climate Change

Compliance with greenhouse gas emissions regulations may result in increased operational costs to the Corporation.

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level.

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or asset write-offs.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete.

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for oil and natural gas and/or increase the Corporation's costs and/or delay planned operations.

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Corporation's operations, which may affect the Corporation's profitability.

In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's financial position.

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Due to seismic activity reported in the Fox Creek area of Alberta, the AER announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. The AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Corporation's financial condition.

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

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract. An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares.

Changing Investor Sentiment

Changing investor sentiment towards the oil and gas industry may impact the Corporation's access to, and cost of, capital.

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees of the Corporation. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Corporation, may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation.

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

Third Party Credit Risk

The Corporation is exposed to credit risk of third party operators or partners of properties in which it has an interest.

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

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Corporation's ability to acquire properties or require a substantial cash deposit with the regulator.

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. These programs 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 generally required. Changes to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance obligations. In addition, the liability management regime may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

In '*Orphan Well Association v Grant Thornton Limited*', the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the provincial OGCA, including the AB LLR Program, and the federal *Bankruptcy and Insolvency Act* (the "**BIA**"). This ruling meant that receivers and trustees of insolvent entities have the right to renounce assets within insolvency proceedings, and was affirmed by a majority of the Alberta Court of Appeal. On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations. See "*Industry Conditions – Liability Management Rating Program – Alberta*".

Operational Dependence

The successful operation of a portion of the Corporation's properties is dependent on third parties.

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

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

Title to Assets

Defects in the title to the Corporation's properties may result in a financial loss.

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

Expiration of Licenses and Leases

The Corporation or its working interest partners may fail to meet the requirements of a licence or lease, causing its termination or expiry.

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions.

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

In addition, acquisitions of oil and gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquiror, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated. Although select title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Corporation's title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated. Such deficiencies or defects could adversely affect the value of the assets acquired and the Corporation's securities.

Reputational Risk Associated with the Corporation's Operations

The Corporation relies on its reputation to continue its operations and to attract and retain investors and employees.

Any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage the Corporation's reputation in the areas in which the Corporation operates. Negative sentiment towards the Corporation could result in a lack of willingness of municipal authorities being willing to grant the necessary licenses or permits for the Corporation to operate its business and in residents in the areas where the Corporation is doing business opposing further operations in the area by the Corporation. If the Corporation develops a reputation of having an unsafe work site it may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultants to operate its business. Further, the Corporation's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which the Corporation has no control. In addition, environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could result in negative investor sentiment towards the Corporation, which may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise.

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

Conflicts of Interest

Conflicts of interest may arise for the Corporation's directors and officers who are also involved with other industry participants.

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Cost of New Technologies

The Corporation's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete.

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

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Corporation's financial condition, results of operations and cash flow.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar affect on the demand for oil and gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Litigation

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation.

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

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Corporation's competitive advantage or put it at risk of litigation.

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

Internal Controls

Material weaknesses in the Corporation's internal controls may negatively affect the Corporation and the market price of the Common Shares.

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's financial statements and harm the trading price of the Common Shares.

Income Taxes

Taxation authorities may reassess the Corporation's tax returns.

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

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

Availability of Drilling Equipment and Access

Restrictions on the availability of and access to drilling equipment may impede the Corporation's exploration and development activities.

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

Seasonality and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and the Corporation may experience significant operational delays as a result.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Roads bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Aboriginal Claims

Aboriginal claims may affect the Corporation.

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

Dividends

The Corporation has paid dividends but there is no assurance that it will do so in the future.

The amount of future cash dividends paid by the Corporation, if any, will be subject to the discretion of the Board and will depend on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. See "*Dividend Record and Policy*".

Expansion into New Activities

Expanding the Corporation's business exposes it to new risks and uncertainties.

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings the Corporation is or was a party to, or that any of its property is or was the subject of, during the Corporation's most recent financial year, nor are any such legal proceedings known to the Corporation to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of the Corporation.

There are no: (a) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority since the Corporation's inception; (b) other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision; and (c) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority within the three years immediately preceding the date of this Annual Information Form.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as described elsewhere in this Annual Information Form, there is no material interest, direct or indirect, of any: (a) director or executive officer of the Corporation; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of the Corporation's voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction within the three years before the date of this Annual Information Form that has materially affected or is reasonably expected to materially affect the Corporation.

PROMOTERS

Joel A. MacLeod, took the initiative in founding Predecessor Highwood and arranging for its organization and, accordingly, may be considered to be the promoter of the Corporation. The following table sets out Mr. MacLeod's shareholdings in the Corporation as at the date hereof.

Name of Promoter	Common Shares Owned, Controlled or Directed, Directly or Indirectly, as at the date hereof	Percentage of Outstanding Common Shares as at the date hereof (1)
1080766 Alberta Ltd.(2)	4,045,862	67.27%

Notes:

(1) Percentages based on 6,013,965 Common Shares issued and outstanding as of the date hereof.

(2) Joel A. MacLeod has beneficial ownership and control of 1080766 Alberta Ltd. Joel A. MacLeod has not received anything of value from the Corporation nor have there been any assets, services or other consideration received or expected to be received by the Corporation other than (a) regarding the exchange of Predecessor Highwood Shares held by Joel A. MacLeod for Common Shares pursuant to the Amalgamation, and (b) regarding the Corporation's purchase of a 55% working interest in 53.4 sections of Doig lands in Fireweed, British Columbia from Predator Oil BC Ltd. in September 2017 for a purchase price of $650,000. 1080766 Alberta Ltd owned 49.0% of Predator Oil BC Ltd. The cost of such assets to Predator Oil BC Ltd. is unable to be determined because such assets represent a portion of an asset package purchased by Predator Oil BC Ltd.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Odyssey Trust Company at its principal office in Calgary, Alberta located at 350-300 5th Avenue S.W., T2P 3C4.

MATERIAL CONTRACTS

There are no material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year but which are still in effect, other than contracts entered into in the ordinary course of business.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than (a) GLJ, the Corporation's independent qualified reserves evaluator, (b) RSM Alberta LLP, the independent external auditor of (i) PBC in respect of the audited annual financial statements of PBC for the period from the date of incorporation, January 25, 2018, to September 30, 2018, and (ii) the Corporation in respect of the audited annual consolidated financial statements for the for the year ended December 31, 2018, and (c) DLA Piper (Canada) LLP, the Corporation's counsel.

As at the date hereof, GLJ and its designated professionals, as a group, beneficially owned, directly or indirectly, less than 1% of the outstanding Common Shares.

RSM Alberta LLP is independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta.

Trevor Wong-Chor, a director of the Corporation, is Partner with DLA Piper (Canada) LLP, a law firm which provides legal services to the Corporation on a fee for services basis. As at the date hereof, DLA Piper (Canada) LLP and its designated professionals, as a group, beneficially owned, directly or indirectly, less than 1% of the outstanding Common Shares.

Other than as noted above, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Highwood.

ADDITIONAL INFORMATION

Additional information including remuneration and indebtedness of directors and officers of Highwood, principal holders of the Common Shares and securities authorized for issuance under equity compensation plans, will be contained in the Information Circular – Proxy Statement of the Corporation which relates to the annual meeting of Shareholders to be held on June 19, 2019. Additional financial information is provided in our financial statements and accompanying Management's Discussion and Analysis for the year ended December 31, 2018, which have been filed on the Corporation's SEDAR profile at www.sedar.com. Other additional information relating to the Corporation may be found on our SEDAR profile at www.sedar.com.

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

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

To the board of directors of Highwood Oil Company Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, 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, 2018, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Dec. 31, 2018	Canada	-	178,790	-	**178,790**

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

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 29, 2019

"Originally Signed by"
Kelly J. Zukowski, P. Eng.
Manager, Engineering

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