2019

Annual Information Form

Dated March 4, 2020

Quality Assets. Sustainable Dividends.

TSX **FRU**

Freehold
ROYALTIES LTD.

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ADVISORIES

Cautionary Statement Regarding Forward-Looking Information and Statements

This Annual Information Form ("**AIF**"), including documents incorporated by reference, contains forward-looking information and statements (collectively "**forward-looking statements**"). These statements, which relate to future events or our future performance, are provided to allow readers to better understand our business and prospects and may not be suitable for other purposes. 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, plan, continue, estimate, expect, may, will, project, predict, potential, targeting, intend, could, might, should, believe and similar expressions (including the negatives thereof). 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 the forward-looking statements included in this AIF are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements speak only as of the date of this AIF. We assume no obligation to revise or update these statements except as required pursuant to applicable securities laws.

In particular, this AIF contains forward-looking statements pertaining to the following:

- Freehold Royalties Ltd.'s ("**Freehold**" or the "**Corporation**") strategy with respect to future acquisitions and the possibility that the Board of Directors may vary the strategy in the future;
- the performance characteristics of our oil and natural gas properties;
- the estimated future value of our oil and natural gas reserves;
- projected oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- estimated abandonment and reclamation costs;
- the expected future development costs associated with development of our reserves;
- plans for development of undeveloped reserves;
- the funding and payment of future dividends;
- the expectations for the funding of capital expenditures;
- the expectation of certain activities to be undertaken by operators in areas in which we have a royalty or working interest;
- the expectation of additional oil or natural gas that may be recovered from certain royalty properties in which we have an interest;
- supply and demand for oil and natural gas;
- our tax horizon and taxability;
- expectations regarding the ability to raise capital and add to reserves through acquisitions and development;
- the performance and characteristics of the oil and natural gas properties in which we have an investment;
- treatment under governmental regulatory regimes and tax laws;

- the expectation that our mineral title lands and gross overriding royalty interests will provide the majority of revenue;
- the intended focus of Freehold's activities undertaken by the Manager towards maximizing dividends to be paid to the Shareholders and acquiring appropriate assets to provide long-term growth in the value of Freehold;
- the expectation that the activities undertaken by Freehold will maximize value to the Shareholders;
- the expectation that Freehold may acquire additional royalties and other forms of oil and natural gas related assets;
- the expectation that properties to be acquired may be operated by competent third parties;
- the expectation that with respect to new royalties, the purchase price paid by Freehold may include two components: an amount paid at closing for a royalty on existing production and an amount paid towards the drilling of a predetermined number of future wells, which may be paid on completion of a specific operational event;
- that drilling activity on the Royalty Lands is anticipated to provide continued new sources of oil and natural gas Royalty Income in future years, with new wells and production therefrom reducing the rate at which production and Royalty Income would otherwise decline;
- the expectation that a minimal amount of capital will be spent on development activities and approximately $2.5 million will be directed to abandonment and reclamation activities on Freehold's working interest properties in 2020;
- the expectation that we will continue to manage our environmental obligations in 2020 with an active wellbore abandonment and site reclamation program, similar in scope to 2019; and
- Freehold's expectations with respect to the treatment, timing and anticipated results/outcome of its proceedings with the CRA.

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

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of royalty reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- risks related to the environment and changing environmental laws, such as, carbon tax and methane emissions regulations;
- geological, technical, drilling, and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "*Risk Factors*".

Forward-looking statements are based on a number of factors and assumptions that have been used to develop such statements but which may prove to be incorrect. Although we believe that the assumptions underlying such forward-looking statements are reasonable, we can give no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur. In addition to other factors and assumptions that may be identified in this AIF, assumptions have been made regarding, among other things:

- the impact of increasing competition;

- the general stability of the economic and political environment in which we have an interest in oil and natural gas properties;
- the timely receipt of any required regulatory approvals;
- the Manager's policies with respect to acquisitions and payments of dividends;
- the ability of the Manager to obtain qualified staff, equipment and services in a timely and cost efficient manner;
- drilling results;
- the ability of the operator of the projects that Freehold has an interest in to operate the field in a safe, efficient and effective manner;
- the continued development of the lands in which we have a royalty interest;
- that third parties such as royalty payors, operators of the lands in which we have a working interest and other contractual counterparties will satisfy their obligations as required;
- our ability to obtain financing on acceptable terms;
- field production rates and decline rates;
- the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration;
- the performance and characteristics of the oil and natural gas properties in which we have an interest;
- the timing and costs of pipeline, storage and facility construction and expansion and the ability of the operator of the properties in which we have an interest to secure adequate product transportation;
- future oil and natural gas prices;
- currency, exchange and interest rates;
- the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which we have an interest in oil and natural gas properties; and
- the ability of the operator of the properties in which we have an interest to successfully market its oil and natural gas products. See "*Reserves Data – Significant Factors and Uncertainties*".

Statements relating to reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

Non-GAAP Financial Measures

Within this AIF, references are made to terms commonly used as key performance indicators in the oil and gas industry. We believe that operating income, royalty operating income and operating netback are useful supplemental measures for management and investors to analyze operating performance, financial leverage, and liquidity, and we use these terms to facilitate the understanding and comparability of our results of operations. However, these terms do not have any standardized meanings prescribed by Canadian generally accepted accounting principles ("**GAAP**") and therefore may not be comparable with the calculations of similar measures for other entities.

Operating income is calculated as royalty and other revenue less royalty and operating expenses. It shows the profitability of our revenue streams as it provides the cash margin for product sold after directly related expenses. Royalty operating income is calculated as royalty revenue less applicable extraction taxes. Operating netback, which is calculated as average unit sales price less royalty and operating expenses, represents the cash margin for product sold, calculated on a per boe basis. For additional information relating to these non-GAAP financial measures see our management's discussion and analysis for the year ended December 31, 2019 which is available on SEDAR at www.sedar.com.

Conversion of Natural Gas to Barrels of Oil Equivalent

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil ("**boe**"). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio based on the current price of crude oil to natural gas is significantly different from the 6:1 energy equivalency ratio, using a conversion ratio on a 6:1 basis may be misleading as an indication of value.

Presentation of Oil and Natural Gas Reserves and Production Information

All oil and natural gas reserve information contained in this AIF has been prepared and presented in accordance with National Instrument 51-101. The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this AIF. The estimated future net revenue from the production of the disclosed oil and natural reserves does not represent the fair market value of these reserves.

GLOSSARY OF TERMS

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

"**1872348**" means 1872348 Alberta Ltd., a corporation incorporated under the ABCA, a wholly-owned subsidiary of Freehold and trustee of FHT.

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

"**Board of Directors**" means the Board of Directors of Freehold.

"**Canpar**" means Canpar Holdings Ltd., a wholly-owned subsidiary of the CN Pension Trust Funds.

"**CN Pension Trust Funds**" means the pension trust funds for employees of Canadian National Railway Company.

"**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.

"**Common Shares**" means the common shares of Freehold.

"**CRA**" means the Canada Revenue Agency.

"**Deferred Share Unit Plan**" means the deferred share unit plan for non-management directors of Freehold whereby fully vested Deferred Share Units are granted annually and dividends to Shareholders declared by Freehold prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of dividends.

"**Deferred Share Units**" means our deferred share units issued pursuant to the Deferred Share Unit Plan that are redeemable for Common Shares any time after the retirement of a member of the Board of Directors.

"**FHT**" means Freehold Holdings Trust, a commercial trust formed under the laws of Alberta.

"**Freehold**", "**us**", "**we**", "**our**" or the "**Corporation**" means Freehold Royalties Ltd., a corporation amalgamated under the ABCA. All references to "Freehold", "us", "we", "our" or the "Corporation", unless the context otherwise requires, are references to Freehold Royalties Ltd., its predecessors, its subsidiaries and partnerships.

"**Freehold (USA)**" means Freehold Royalties (USA) Inc., a corporation formed under the laws of the state of Delaware, USA.

"**GORR**" means gross overriding royalty.

"**Governance Agreement**" means the governance agreement between the Manager and Freehold dated as of December 31, 2010.

"**Gross**" or "**gross**" means:

- in relation to production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including our royalty interests;
- in relation to wells, the total number of wells in which we have an interest; and
- in relation to properties, the total area of properties in which we have an interest.

"**Management Agreement**" means the fourth amended and restated agreement dated November 9, 2015 among the Manager, Rife, Freehold, FHT and the Partnership, which amended and restated the Original Management Agreement, pursuant to which the Manager provides management services to Freehold, FHT and the Partnership.

"**Management Fee**" means the fee payable to the Manager pursuant to the Management Agreement.

"**Manager**" means Rife Resources Management Ltd., a wholly-owned subsidiary of Rife.

"**Net**" or "**net**" means:

- in relation to production and reserves, our working interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interests;

- in relation to wells, except as otherwise provided herein, the number of wells obtained by aggregating our working interest in each of its gross wells; and
- in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.

"**NI 51-101**" means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

"**NI 51-102**" means National Instrument 51-102 *Continuous Disclosure Obligations*.

"**Original Management Agreement**" means the management agreement dated November 25, 1996 among the Manager, Freehold Resources Ltd., and Freehold Royalty Trust, as amended and restated by the first amended and restated management agreement dated May 10, 2006 among the Manager, Freehold Resources Ltd., and Freehold Royalty Trust, as amended and restated by the second amended and restated management agreement dated January 1, 2011 among the Manager, Freehold, Freehold Resources Ltd., and the Partnership, as amended and restated by the third amended and restated management agreement dated January 23, 2015 among the Manager, Freehold, FHT, and the Partnership.

"**Partnership**" means Freehold Royalties Partnership, a general partnership formed under the laws of Alberta.

"**Preferred Shares**" means the preferred shares of Freehold.

"**Proved**" and "**probable**" reserves have the meanings given to those terms under "*Reserves Data - Disclosure of Reserves Data*".

"**Rife**" means Rife Resources Ltd., a wholly-owned subsidiary of the CN Pension Trust Funds.

"**Royalty Income**" means our income from our royalties in oil, natural gas, NGL and potash resources.

"**Royalty Lands**" means our lands from which we derive Royalty Income.

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval.

"**Shareholders**" means the holders from time to time of Common Shares.

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder.

"**Trimble**" means Trimble Engineering Associates Ltd., independent qualified reserves evaluators of Calgary, Alberta.

"**Trimble Report**" means the report dated January 30, 2020 prepared by Trimble, evaluating our oil, natural gas, natural gas liquids, and sulphur reserves as at December 31, 2019.

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

"**USA**" or "**United States**" means the United States of America.

Abbreviations

AECO	reference pricing point for natural gas at a natural gas storage facility near the Alberta-Saskatchewan border
API	American Petroleum Institute
°API	the measure of the density of liquid petroleum products derived from a specific gravity
bbl and bbls	barrel and barrels, respectively, each barrel representing 34.972 imperial gallons or 42 U.S. gallons
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mbbls	one thousand barrels
Mboe	one thousand barrels of oil equivalent
MMbbls	one million barrels
MMboe	one million barrels of oil equivalent
MMBtu	one million British Thermal Units
Mcf	one thousand cubic feet
Mcf/d	one thousand cubic feet per day
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
NGL	natural gas liquids
WTI	West Texas Intermediate

Conversion Factors

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.471

All dollar amounts set forth in this AIF are in Canadian dollars, except where otherwise indicated.

CORPORATE STRUCTURE

General

Freehold is a dividend paying oil and gas corporation based in Calgary, which, directly or indirectly, acquired all of the assets and assumed all of the liabilities of Freehold Royalty Trust pursuant to a plan of arrangement completed on January 1, 2011.

On January 23, 2015, Freehold completed a restructuring pursuant to which it amalgamated first with its wholly-owned subsidiary, 1851328 Alberta Ltd., and subsequently with another wholly owned subsidiary, Freehold Resources Ltd. The articles and by-laws of Freehold were not amended as a result of the amalgamation.

Freehold enables its Shareholders to participate in the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold, FHT, the Partnership and Freehold (USA). The head, principal and registered office of Freehold is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

Rife Resources Management Ltd.

The Manager was incorporated under the *Corporations Act* (Ontario) on March 5, 1968 under the name "75-89 Gosford Limited" and continued under the *Canada Business Corporations Act* on April 20, 1979. The Manager changed its name to "Rife Resources Management Ltd." on October 1, 1996. Pursuant to the Management Agreement, Freehold, FHT and the Partnership retained the Manager for the purposes of identifying, evaluating and assisting with the acquisition, disposition and ongoing management and administration of the royalties, working interest properties and other oil, natural gas and potash resources held by Freehold, FHT and the Partnership. The head, principal and registered office of the Manager is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

Pursuant to an agreement between Rife and the Manager, Rife provides the Manager, which is a wholly-owned subsidiary of Rife, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to Freehold, FHT and the Partnership on a cost recovery basis. Freehold benefits from the fact that Rife has been in operation for more than 35 years and many of Rife's personnel have extensive experience managing the assets underlying Freehold's royalty and working interest assets. In addition, Rife manages two private entities that are also engaged in oil and gas operations and as a result Rife has assembled a diversified and experienced staff to manage the assets of Freehold. These organizational and synergistic benefits are advantageous to Shareholders. The general practice of the management of Rife is to ensure that Freehold receives priority to consider acquisition opportunities for royalty interests. In addition, the Management Fee paid to the Manager is paid in Common Shares, which the Board believes aligns the interests of the Manager with the interests of the Shareholders. Based on these factors, the Board believes that maintaining Freehold's relationship with the Manager is in the best interests of Freehold.

Pursuant to the Governance Agreement, the Manager is entitled to nominate for election two individuals as directors of Freehold provided that the Manager and its affiliates, including the CN Pension Trust Funds, hold 10% or more of the issued and outstanding Common Shares. If the Manager and its affiliates hold less than 10% of the issued and outstanding Common Shares, the Manager will have the right to nominate for election one individual as a director of Freehold. If the individuals nominated by the Manager fail to get elected or if the Manager ceases to hold any Common Shares (in which case the Manager will not have the right to nominate any individuals as directors of Freehold) but continues to act as manager of Freehold pursuant to the Management Agreement, the Governance Agreement will provide the Manager with the right to have an observer present at all meetings of directors of Freehold. The CN Pension Trust Funds currently holds, directly or indirectly, approximately 21.9% of the outstanding Common Shares and as a result, has the right to nominate two individuals as directors of Freehold.

Freehold Holdings Trust

FHT is a commercial trust formed under the laws of Alberta. All of the issued and outstanding trust units of FHT are held by Freehold and 1872348 is the trustee of FHT. The head office of FHT is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

1872348 Alberta Ltd.

All of the issued and outstanding shares of 1872348 are held by Freehold. The head, principal and registered office of 1872348 is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

Freehold Royalties Partnership

The Partnership is a general partnership formed under the laws of Alberta. On December 13, 2010, the Partnership changed its name from "Petrovera Resources" to "Freehold Royalties Partnership". Freehold and FHT are the general partners of the Partnership. Freehold is the managing partner of the Partnership. The head office of the Partnership is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

Freehold Royalties (USA) Inc.

Freehold (USA) is a corporation formed under the laws of the state of Delaware, USA. All of the issued and outstanding shares of Freehold (USA) are held by Freehold. The head and principal office of Freehold (USA) is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8. The registered office of Freehold (USA) is located at 251 Little Falls Drive, Wilmington, Delaware, USA 19808.

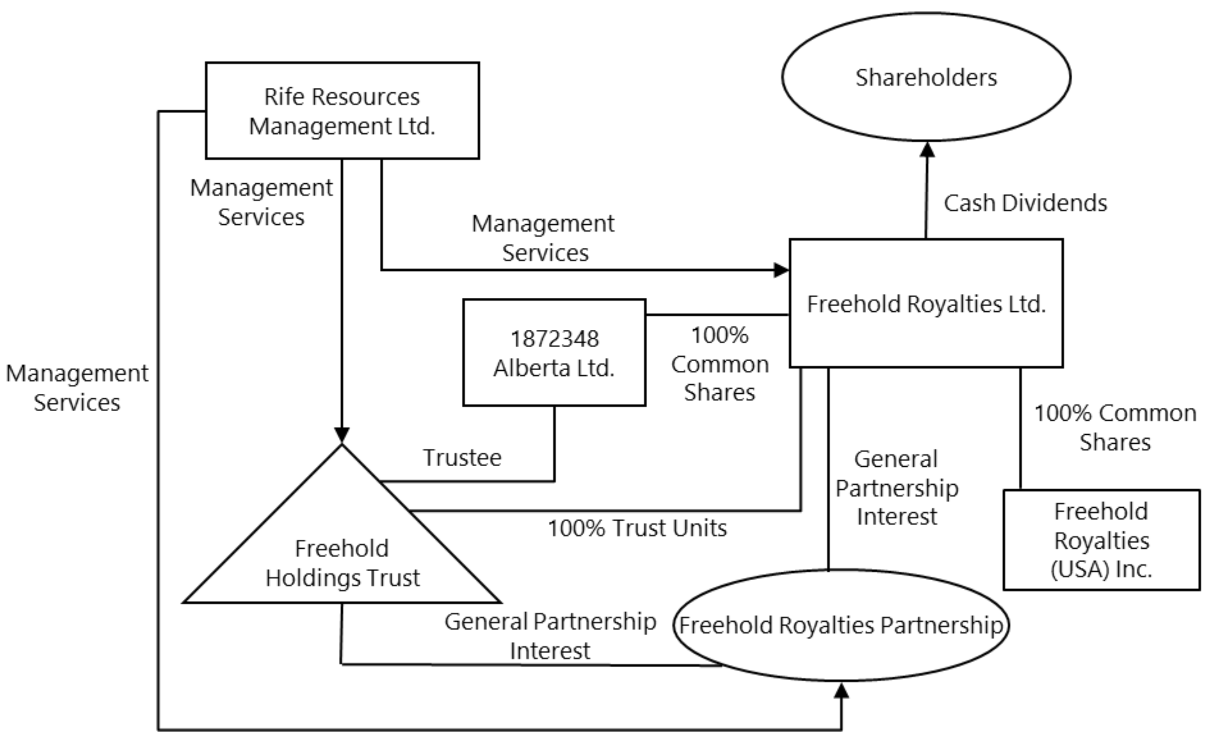
Structure of the Corporation

The following table provides the name, the percentage of voting securities owned by Freehold and the jurisdiction of incorporation, continuance or formation of our subsidiaries and partnerships, either direct or indirect, as at the date hereof.

	Percentage of Voting Securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Freehold Royalties Partnership	100%	General Partnership	Alberta
Freehold Holdings Trust	100%	Commercial Trust	Alberta
1872348 Alberta Ltd.	100%	Corporation	Alberta
Freehold Royalties (USA) Inc.	100%	Corporation	Delaware

Organizational Structure of the Corporation

The following diagram sets forth the organizational structure of Freehold.



GENERAL DEVELOPMENT OF BUSINESS

The following is a summary description of the development of our business since January 1, 2017.

Year Ended December 31, 2017

In February 2017, Freehold closed a $34 million acquisition of various GORRs and mineral title lands in the greater Dodsland area of Saskatchewan. The acquisition added approximately 185 boe/d of production (91% oil) in 2017 and 32,000 acres of Royalty Lands including 6,500 net acres of mineral titles.

In April 2017, Freehold sold all of its working interest assets located in southeast Saskatchewan for $29 million. Total production and operating income associated with these assets in 2017 was approximately 750 boe/d and $4.3 million, respectively, at the time of closing. Related decommissioning liabilities removed as a result of this sale amounted to $4.8 million (over 300 gross wells plus related facilities).

In December 2017, Freehold acquired a new 2% GORR in Cardium petroleum and natural gas rights in 166,000 gross acres of land in the greater Pembina area in Alberta. The purchase price of the GORR was $52 million plus the assignment by Freehold of minor working interest assets. The acquired GORR was producing approximately 210 boe/d (74% light oil) at the time of closing.

Year Ended December 31, 2018

In February 2018, Freehold disposed of our non-core working interest in the Pembina Cardium Unit No. 9 in Alberta for $8 million. As part of the transaction Freehold retained a 4% GORR on the same interests that were sold. Average production and operating income associated with the asset in 2017 was 179 boe/d and $2.1 million (before GORR), respectively. This deal reduced our decommissioning liability by approximately 40 net working interest wells and also reduced our exposure to capital activities as Freehold had $2.4 million of capital expenditures related to the property in 2017.

In February 2018, Freehold completed a $7.0 million royalty acquisition in the prospective East Shale Duvernay Basin in central Alberta. As part of the transaction, Freehold acquired a 1.0% GORR on approximately 113,920 gross acres and a 3.0% GORR on 1,920 gross acres of Royalty Lands.

In March 2018, Freehold closed two royalty acquisitions, including a 0.2% lessor royalty on the Weyburn Unit in Saskatchewan and a new 1.9% GORR on the Mitsue Gilwood Sand Unit #1 in Alberta. The purchase price associated with these transactions was $24 million and the assignment by Freehold of certain minor working interest assets. Production associated with the acquired royalty interests was approximately 110 boe/d (100% oil) at the time of closing.

In August 2018 Freehold closed the purchase of 64,000 acres of Royalty Lands with approximately 90 boe/d of production at the time of closing (one-third oil and NGL) in Alberta for $5.9 million and the assignment of certain minor working interest assets.

In September 2018 Freehold closed the purchase of a GORR across 109,000 acres of land with prospectivity for the Clearwater formation in the Jarvie and Nipisi areas of Alberta for $12 million.

In November 2018 Freehold closed a $9 million acquisition of mineral title and GORRs in southwest Saskatchewan with production of approximately 55 boe/d at the time of closing.

All acquisition transactions in 2018 were funded through Freehold's existing credit facilities and funds from operations.

Year Ended December 31, 2019

In June 2019, Freehold closed a $30.0 million acquisition of a gross overriding royalty with drilling commitments on the part of the vendor on certain light and medium oil reservoirs in central and northern Alberta and southwest Saskatchewan. Production (primarily oil) associated with the acquired assets after closing the transaction was 250 boe/d.

In July 2019, Freehold closed a US$9.8 million acquisition of certain royalty assets located in North Dakota. In addition, we completed the acquisition of a further 230 net mineral acres in North Dakota for total cash consideration of US$1.3 million. Production (primarily oil) associated with Freehold's U.S. assets after closing these transactions was 115 boe/d.

Significant Acquisitions

During the year ended December 31, 2019, Freehold did not complete any acquisitions that would be considered significant pursuant to NI 51-102.

BUSINESS OF THE CORPORATION

Overview

Freehold is an Alberta-based, dividend-paying corporation with a focus on royalty assets. Freehold receives revenue from properties as oil, natural gas, and potash are produced. Freehold has a diverse production base. Freehold has interests in more than 45,000 wells (of which over 44,700 are royalty wells including over 23,000 unitized wells). Freehold receives Royalty Income from approximately 11,000 producing wells throughout western Canada and in the State of North Dakota, USA, and minor working interests throughout western Canada. Freehold's royalty interests include significant mineral title and gross overriding royalty interests that will provide the majority of revenue. Royalties offer the benefit of sharing in production, without exposure to the capital, operating and environmental costs associated with oil, natural gas, and potash production. Oil, natural gas, and potash are finite resources. Over time, reserves are depleted and capital investment is required to sustain production and cash flow. Freehold replaces production by encouraging producers to drill on their land and by acquiring royalty interests.

Management Policies and Acquisition Strategy

The Manager manages Freehold, FHT and the Partnership in accordance with the Management Agreement. The Manager utilizes the extensive experience of Rife staff and employs prudent oil and gas business practices to increase the assets of Freehold through the acquisition of royalty interests in oil and natural gas properties.

Freehold may, directly or indirectly through its subsidiaries and partnerships, acquire additional royalties and other forms of oil and natural gas related assets that are primarily of a low risk nature. Properties to be acquired are operated by competent third parties.

Freehold's acquisition strategy targets individual properties, or groups of properties with a focus on royalty interests, to provide long-term growth in value. The key criteria are:

- quality assets;
- attractive returns;
- acceptable risk profile; and
- long economic life.

These criteria serve as guidelines for the Manager on presenting acquisitions for approval by the Board of Directors. The Board of Directors may vary these criteria for any particular acquisition based on the Manager's recommendations and consideration of the qualitative aspects of the subject properties.

The acquisition of additional royalties by Freehold includes existing contractual royalties and newly created royalties. With respect to new royalties, the purchase price paid by Freehold may include two components: an amount paid at closing for a royalty on existing production and an amount paid towards the drilling of a predetermined number of future wells, which may be paid on completion of a specific operational event.

Environmental and Sustainability Oversight

As a royalty owner, Freehold does not directly operate any of our royalty assets. Royalty owners are not generally responsible for operating or capital costs, or environmental or reclamation liabilities. The projects on which we receive royalty revenue are owned and operated by independent oil and gas companies. Our royalty payors include some of the largest and most recognized oil and gas companies in the Canadian and United States oil and gas industry. These companies are required to operate in ethical, safe and environmentally responsible manner in accordance with the Canadian and United States regulatory framework.

Freehold also owns working interests in oil and natural gas properties. Our working interest assets represented less than 1% of our total operating income and 4% of total production in 2019. We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of our working interest properties upon abandonment. Environment, health and safety falls under the responsibility of Rife as manager of Freehold’s assets. Rife has a comprehensive program that includes policies and procedures designed to protect the environment and the health and safety of its employees, contractors, and the public. Rife assesses Freehold’s environmental, health and safety liabilities through pre-acquisition assessments, periodic assessments, and audits. Environmental, health and safety exposures are tracked and addressed with short and long-term initiatives.

Freehold is committed to conducting our business in a manner that respects the environment and minimizes the impact that our operations may have on the quality of the air, land and water that surround us. We have an active well abandonment and site reclamation program for our working interest assets that ensures wells and facilities are decommissioned and abandoned at the end of their economic life. This proactive abandonment program is designed to mitigate any potential public or environmental risks and to maintain compliance with regulatory requirements. In 2019, Freehold participated as a working interest owner in the abandonment of 66 wellbores. For 2020, we will continue to manage our environmental obligations with another active wellbore abandonment and site reclamation program, similar in scope to 2019.

A detailed description of Freehold's corporate reporting initiatives and a discussion of environmental, social and governance issues are contained in Freehold's 2019 Environmental, Social and Governance Report, which can be found on Freehold's website at www.freeholdroyalties.com but is not to be considered part of this AIF.

RESERVES DATA

Our statement of reserves data and other oil and natural gas information is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2019, and the preparation date of the Statement is January 30, 2020.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Reserves Data and Other Information in Form 51-101F3 are attached as Appendices A and B, respectively.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by an independent qualified reserves evaluator, Trimble, with an effective date of December 31, 2019 contained in the Trimble Report. The Reserves Data summarizes the crude oil, natural gas and natural gas liquids of Freehold and the net present values of future net revenue for these reserves using forecast prices and costs. Trimble also evaluated certain sulphur reserves of Freehold; however, as such sulphur reserves are immaterial to Freehold they have not been presented herein. The Trimble Report has been prepared in accordance with NI 51-101 and the standards and reserves definitions contained in the COGE Handbook. Information not required by NI 51-101 has been presented to provide continuity and additional information that we believe is important to the readers of this information. Freehold engaged Trimble to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Freehold's reserves are in Canada and the United States and, specifically, in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, and Ontario and in the state of North Dakota, United States.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Freehold's crude oil, natural gas and natural gas liquids 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 may be greater than or less than the estimates provided herein.

SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS(1)(2)

CANADA

Reserves Category	Light & Medium Crude Oil Gross (Mbbls)	Light & Medium Crude Oil Net (Mbbls)	Tight Oil Gross (Mbbls)	Tight Oil Net (Mbbls)	Heavy Crude Oil Gross (Mbbls)	Heavy Crude Oil Net (Mbbls)
Proved						
Developed producing	135	4,291	-	838	94	2,502
Developed non-producing	11	14	-	-	-	-
Undeveloped	-	1,484	-	72	-	216
Total proved	147	5,789	-	910	94	2,719
Probable	190	4,284	-	355	136	1,072
Total proved plus probable	337	10,073	-	1,265	230	3,790

Reserves Category	Conventional Natural Gas Gross (MMcf)	Conventional Natural Gas Net (MMcf)	Coal Bed Methane Gross (MMcf)	Coal Bed Methane Net (MMcf)	Shale Gas Gross (MMcf)	Shale Gas Net (MMcf)
Proved						
Developed producing	1,377	46,976	3	1,368	-	1,153
Developed non-producing	175	175	-	-	96	88
Undeveloped	-	4,656	-	-	-	964
Total proved	1,551	51,807	3	1,368	96	2,205
Probable	1,545	24,551	1	418	64	974
Total proved plus probable	3,096	76,358	4	1,786	160	3,180

Reserves Category	Natural Gas Liquids Gross (Mbbls)	Natural Gas Liquids Net (Mbbls)	Total Oil Equivalent Gross (Mboe)	Total Oil Equivalent Net (Mboe)
Proved				
Developed producing	60	1,510	520	17,390
Developed non-producing	11	9	68	67
Undeveloped	-	119	-	2,829
Total proved	71	1,638	587	20,286
Probable	126	823	720	10,857
Total proved plus probable	197	2,461	1,307	31,143

UNITED STATES

Reserves Category	Tight Oil Gross (Mbbls)	Tight Oil Net (Mbbls)	Conventional Natural Gas Gross (MMcf)	Conventional Natural Gas Net (MMcf)	Total Oil Equivalent Gross (Mboe)	Total Oil Equivalent Net (Mboe)
Proved						
Developed producing	-	71	-	129	-	93
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-
Total proved	-	71	-	129	-	93
Probable	-	393	-	695	-	509
Total proved plus probable	-	464	-	824	-	602

TOTAL

Reserves Category	Light & Medium Crude Oil Gross (Mbbls)	Light & Medium Crude Oil Net (Mbbls)	Tight Oil Gross (Mbbls)	Tight Oil Net (Mbbls)	Heavy Crude Oil Gross (Mbbls)	Heavy Crude Oil Net (Mbbls)
Proved						
Developed producing	135	4,291	-	909	94	2,502
Developed non-producing	11	14	-	-	-	-
Undeveloped	-	1,484	-	72	-	216
Total proved	147	5,789	-	981	94	2,719
Probable	190	4,284	-	748	136	1,072
Total proved plus probable	337	10,073	-	1,729	230	3,790

Reserves Category	Conventional Natural Gas Gross (MMcf)	Conventional Natural Gas Net (MMcf)	Coal Bed Methane Gross (MMcf)	Coal Bed Methane Net (MMcf)	Shale Gas Gross (MMcf)	Shale Gas Net (MMcf)
Proved						
Developed producing	1,377	47,104	3	1,368	-	1,153
Developed non-producing	175	175	-	-	96	88
Undeveloped	-	4,656	-	-	-	964
Total proved	1,551	51,936	3	1,368	96	2,205
Probable	1,545	25,246	1	418	64	974
Total proved plus probable	3,096	77,182	4	1,786	160	3,180

Reserves Category	Natural Gas Liquids Gross (Mbbls)	Natural Gas Liquids Net (Mbbls)	Total Oil Equivalent Gross (Mboe)	Total Oil Equivalent Net (Mboe)
Proved				
Developed producing	60	1,510	520	17,483
Developed non-producing	11	9	68	67
Undeveloped	-	119	-	2,829
Total proved	71	1,638	587	20,379
Probable	126	823	720	11,366
Total proved plus probable	197	2,461	1,307	31,744

(1) Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include royalties receivable. Net reserves are comprised of working interests minus royalties payable plus royalties receivable. The majority of our assets are royalty interests. This causes our gross reserves to be lower than our net reserves and may hinder an investor's ability to compare our reserves with others in our industry.
(2) Columns may not add due to rounding.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2019 FORECAST PRICES AND COSTS[(1)(2)(3)]

CANADA	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	724,370	543,921	441,834	375,874	329,488
Developed non-producing	(9,602)	(7,989)	(6,841)	(5,983)	(5,320)
Undeveloped	155,033	120,770	97,245	80,354	67,797
Total proved	869,801	656,701	532,238	450,245	391,965
Probable	593,691	338,168	219,404	154,169	114,591
Total proved plus probable	1,463,492	994,869	751,641	604,414	506,556

CANADA	After Income Taxes[(2)], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	724,370	543,921	441,834	375,874	329,488
Developed non-producing	(9,602)	(7,989)	(6,841)	(5,983)	(5,320)
Undeveloped	130,895	102,509	83,152	69,288	58,976
Total proved	845,663	638,440	518,145	439,180	383,145
Probable	455,323	256,770	166,101	116,832	87,145
Total proved plus probable	1,300,986	895,210	684,246	556,011	470,289

UNITED STATES	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	5,608	4,535	3,898	3,469	3,155
Developed non-producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
Total proved	5,608	4,535	3,898	3,469	3,155
Probable	31,387	20,868	15,629	12,460	10,314
Total proved plus probable	36,995	25,403	19,527	15,928	13,469

UNITED STATES	After Income Taxes[(2)], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	5,608	4,535	3,898	3,469	3,155
Developed non-producing	-	-	-	-	-
Undeveloped	-	-	-	-	-
Total proved	5,608	4,535	3,898	3,469	3,155
Probable	27,159	17,747	13,126	10,369	8,522
Total proved plus probable	32,766	22,282	17,025	13,838	11,678

TOTAL	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	729,978	548,456	445,732	379,343	332,644
Developed non-producing	(9,602)	(7,989)	(6,841)	(5,983)	(5,320)
Undeveloped	155,033	120,770	97,245	80,354	67,797
Total proved	875,409	661,236	536,136	453,714	395,121
Probable	625,078	359,036	235,032	166,628	124,904
Total proved plus probable	1,500,487	1,020,272	771,169	620,342	520,025

TOTAL	After Income Taxes(2), Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	729,978	548,456	445,732	379,343	332,644
Developed non-producing	(9,602)	(7,989)	(6,841)	(5,983)	(5,320)
Undeveloped	130,895	102,509	83,152	69,288	58,976
Total proved	851,271	642,975	522,043	442,649	386,300
Probable	482,481	274,517	179,227	127,201	95,667
Total proved plus probable	1,333,752	917,492	701,271	569,850	481,967

(1) Columns may not add due to rounding

(2) Based on the inclusion of $822,540 of tax pools for Canada and $15,893 of tax pools for the United States

(3) Estimates of future net revenue reflect a deduction for estimated operating costs and abandonment, decommissioning and reclamation costs for all wells (both existing and undrilled and active and inactive wells) whether or not such wells have been attributed reserves as well as for pipelines and facilities. See "*Environmental Obligations – Additional Information Concerning Abandonment. Decommissioning and Reclamation Costs*".

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS[1]

	Proved Reserves		
($000s)	Canada	United States	Total
Royalty Income	889,561	5,619	895,179
Revenue from working interest properties	24,923	-	24,923
Royalty expense on working interest properties	(2,653)	-	(2,653)
Operating costs[2]	(32,597)	(11)	(32,608)
Development costs	(57)	-	(57)
Abandonment and reclamation costs[2]	(9,375)	-	(9,375)
Future net revenue before income taxes	869,801	5,608	875,409
Future income taxes	(24,138)	-	(24,138)
Future net revenue after income taxes	845,663	5,608	851,271

	Proved Plus Probable Reserves		
($000s)	Canada	United States	Total
Royalty Income	1,478,978	37,060	1,516,038
Revenue from working interest properties	58,682	-	58,682
Royalty expense on working interest properties	(7,405)	-	(7,405)
Operating costs[2]	(51,819)	(65)	(51,884)
Development costs	(4,784)	-	(4,784)
Abandonment and reclamation costs[2]	(10,161)	-	(10,161)
Future net revenue before income taxes	1,463,492	36,995	1,500,487
Future income taxes	(162,506)	(4,229)	(166,734)
Future net revenue after income taxes	1,300,986	32,766	1,333,752

(1) Columns may not add due to rounding
(2) Estimates of future net revenue reflect a deduction for estimated operating costs and abandonment, decommissioning and reclamation costs for all wells (both existing and undrilled and active and inactive wells) whether or not such wells have been attributed reserves as well as for pipelines and facilities. See "*Environmental Obligations – Additional Information Concerning Abandonment. Decommissioning and Reclamation Costs*".

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS(1)(2)

CANADA

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	Unit Value(3)
		($000s)	($)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	284,313	49.11/bbl
	Tight Oil (including solution gas and other by-products)	42,417	46.61/bbl
	Heavy Crude Oil (including solution gas and other by-products)	103,104	37.93/bbl
	Conventional Natural Gas (including by-products)	103,744	2.32/Mcf
	Coal Bed Methane (including by-products)	1,887	1.38/Mcf
	Shale Gas (including by-products)	4,207	1.91/Mcf
	Total Proved	539,672	26.60/boe
Proved plus probable	Light and Medium Crude Oil (including solution gas and other by-products)	432,515	42.94/bbl
	Tight Oil (including solution gas and other by-products)	53,861	42.59/bbl
	Heavy Crude Oil (including solution gas and other by-products)	130,309	34.38/bbl
	Conventional Natural Gas (including by-products)	134,685	2.10/Mcf
	Coal Bed Methane (including by-products)	2,269	1.27/Mcf
	Shale Gas (including by-products)	5,438	1.71/Mcf
	Total Proved Plus Probable	759,076	24.37/boe

UNITED STATES

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	Unit Value(3)
Proved		($000s)	($)
	Tight Oil (including solution gas and other by-products)	3,898	54.52/bbl
	Conventional Natural Gas (including by-products)	-	-
	Total Proved	3,898	41.93/boe
Proved plus probable	Tight Oil (including solution gas and other by-products)	19,527	42.05/bbl
	Conventional Natural Gas (including by-products)	-	-
	Total Proved Plus Probable	19,527	32.45/boe

TOTAL

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	Unit Value[3]
		($000s)	($)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	284,313	49.11/bbl
	Tight Oil (including solution gas and other by-products)	46,315	47.19/bbl
	Heavy Crude Oil (including solution gas and other by-products)	103,104	37.93/bbl
	Conventional Natural Gas (including by-products)	103,744	2.32/Mcf
	Coal Bed Methane (including by-products)	1,887	1.38/Mcf
	Shale Gas (including by-products)	4,207	1.91/Mcf
	Total Proved	543,570	26.67/boe
Proved plus probable	Light and Medium Crude Oil (including solution gas and other by-products)	432,515	42.94/bbl
	Tight Oil (including solution gas and other by-products)	73,388	42.44/bbl
	Heavy Crude Oil (including solution gas and other by-products)	130,309	34.38/bbl
	Conventional Natural Gas (including by-products)	134,685	2.10/Mcf
	Coal Bed Methane (including by-products)	2,269	1.27/Mcf
	Shale Gas (including by-products)	5,438	1.71/Mcf
	Total Proved Plus Probable	778,603	24.53/boe

(1) Columns may not add due to rounding.
(2) For the purposes of calculating future net revenue by product type, operating and abandonment, decommissioning and reclamation costs have been excluded for inactive wells as such costs have not been allocated by product type.
(3) The Unit Value is calculated by dividing the discounted Future Net Revenue by the net reserves for the principal product of the Product Type.

Definitions and Other Notes

1. Columns may not add due to rounding.
2. The oil, natural gas and natural gas liquids reserves estimates presented in the Trimble Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

   - analysis of drilling, geological, geophysical and engineering data;
   - the use of established technology; and
   - specified economic conditions.

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

   (a) 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.

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

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

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

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

    (i) 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.

    (ii) 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.

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

Levels of Certainty for Reported Reserves

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

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

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

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

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

3. Forecast Prices and Costs

Forecast prices and costs are those:

(a) generally acceptable 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 Freehold 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).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Oil and natural gas benchmark reference pricing, inflation and exchange rates as at December 31, 2019 utilized in the Trimble Report were as follows:

FORECAST PRICES USED IN ESTIMATES
AS OF DECEMBER 31, 2019

	Oil					Natural Gas		Natural Gas Liquids			Inflation Rate	Exchange Rate
Year	WTI Cushing Oklahoma $US/ bbl	Canadian Light Sweet 40° API $Cdn/ bbl	Hardisty Heavy 12° API $Cdn/ bbl	Hardisty Bow River 24.9° API $Cdn/ bbl	Western Canadian Select 20.5° API $Cdn/ bbl	AECO 30 Day Spot $Cdn/ MMBtu	Henry Hub $US/ MMbtu	Propane $Cdn/ bbl	Butane $Cdn/ bbl	Pentane $Cdn/ bbl	%/ Year	$US/$ Cdn
2020	61.00	73.84	55.38	61.29	59.81	2.04	2.80	25.07	37.72	76.32	2.00	0.76
2021	65.00	78.51	59.66	64.77	63.98	2.27	3.00	31.84	43.90	80.52	2.00	0.77
2022	67.00	78.73	59.04	64.55	63.77	2.81	3.25	32.43	47.74	80.00	2.00	0.80
2023	68.34	80.30	60.22	65.85	65.04	2.89	3.32	33.26	48.69	81.68	2.00	0.80
2024	69.71	81.91	61.43	67.16	66.34	2.98	3.38	34.12	49.67	83.38	2.00	0.80
2025	71.10	83.54	62.66	68.51	67.67	3.06	3.45	34.99	50.66	85.13	2.00	0.80
2026	72.52	85.21	63.91	69.88	69.02	3.15	3.52	35.88	51.67	86.90	2.00	0.80
2027	73.97	86.92	65.19	71.27	70.40	3.24	3.59	36.78	52.71	88.72	2.00	0.80
2028	75.45	88.66	66.49	72.70	71.81	3.33	3.66	37.71	53.76	90.57	2.00	0.80
2029	76.96	90.43	67.82	74.15	73.25	3.42	3.73	38.65	54.84	92.45	2.00	0.80
2030	78.50	92.24	69.18	75.64	74.71	3.51	3.81	39.61	55.93	94.38	2.00	0.80
Thereafter, per year:												
	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	2.00	0.80

The following table provides the historical weighted average prices realized by Freehold for the year ended December 31, 2019:

FREEHOLD WEIGHTED AVERAGE PRICES
YEAR ENDED DECEMBER 31, 2019

	Light and Medium Crude Oil ($/bbl)	Heavy Crude Oil ($/bbl)	Natural Gas ($/Mcf)	Natural Gas Liquids ($/bbl)	Oil Equivalent ($/boe)
Canada					
Freehold weighted average price	65.21	55.97	1.47	31.34	36.15
United States					
Freehold weighted average price	71.44	-	3.87	13.50	62.65

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

5. "Exploratory well" means a well that is not a development well, a service well or a stratigraphic test well.

6. "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas from 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, natural gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

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

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

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

   (c) dry hole contributions and bottom hole contributions;

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

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

8. "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.

9. Future Development Costs

   The following table sets forth development costs deducted in the estimation of Freehold's future net revenue attributable to the reserve categories noted below, based on forecast prices and costs.

FUTURE DEVELOPMENT COSTS
AS OF DECEMBER 31, 2019

	Canada		United States		Total	
Year	Proved Reserves (undiscounted) ($000s)	Proved Plus Probable Reserves (undiscounted) ($000s)	Proved Reserves (undiscounted) ($000s)	Proved Plus Probable Reserves (undiscounted) ($000s)	Proved Reserves (undiscounted) ($000s)	Proved Plus Probable Reserves (undiscounted) ($000s)
2020	50	174	-	-	50	174
2021	7	4,430	-	-	7	4,430
2022	-	36	-	-	-	36
2023	-	53	-	-	-	53
2024	-	37	-	-	-	37
Remainder	-	55	-	-	-	55
Total	57	4,784	-	-	57	4,784

The source of funding for future development costs will be internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue are not expected to be materially affected by the costs of funding the future development expenditures.

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

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

12. The after-tax net present value calculation of our reserves reflects the tax burden on our properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying management's discussion and analysis for additional tax information.

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

Reconciliation of Changes in Reserves

The following table is a reconciliation of gross reserves and is provided as a requirement of NI 51-101. Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include any royalties receivable. Net reserves are working interests minus royalties payable plus royalties receivable. As the majority of our assets are royalty interests, they are excluded from this table. This hinders an investor's ability to compare our reserves to exploration and development companies. Therefore in addition to presenting the reconciliation using gross reserves, we have also presented the reconciliation using net reserves.

As Freehold did not have any reserves in the United States as at December 31, 2018, no reconciliations have been prepared for the United States. As all of the interests acquired by Freehold in North Dakota, United States in 2019 were royalty interests, the reserves associated with such interests would not be reflected in gross reserves. As such, Freehold has only presented a gross reserves reconciliation for Canada which also represents the gross reserves reconciliation for Freehold's total assets. The reconciliation below for the total assets of Freehold presented on a net basis reflects the acquisition of Freehold's United States assets in 2019.

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

CANADA AND TOTAL	**Light and Medium Crude Oil**			**Tight Oil**			**Heavy Crude Oil**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2018	130	185	315	24	125	149	99	145	244
Production	(15)	-	(15)	(2)	-	(2)	(51)	-	(51)
Technical revisions	73	11	83	-	-	-	65	(1)	64
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(9)	(6)	(14)	(22)	(125)	(147)	(18)	(6)	(23)
Economic factors	(33)	-	(33)	-	-	-	(1)	(2)	(3)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2019[1]	**147**	**190**	**337**	**-**	**-**	**-**	**94**	**136**	**230**

CANADA AND TOTAL	**Conventional Natural Gas**			**Coal Bed Methane**			**Shale Gas**		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2018	2,234	2,110	4,345	3	1	4	97	62	160
Production	(307)	-	(307)	(1)	-	(1)	-	-	-
Technical revisions	56	(584)	(528)	1	-	1	-	-	-
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(27)	(12)	(39)	-	-	-	-	-	-
Economic factors	(405)	30	(375)	-	-	-	(2)	2	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2019[1]	**1,551**	**1,545**	**3,096**	**3**	**1**	**4**	**96**	**64**	**160**

CANADA AND TOTAL	**Natural Gas Liquids**			**Total Oil Equivalent**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2018	74	132	206	716	949	1,665
Production	(13)	-	(13)	(132)	-	(132)
Technical revisions	17	(8)	9	165	(96)	69
Extensions and improved recovery	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(3)	(1)	(4)	(56)	(139)	(195)
Economic factors	(3)	3	(1)	(105)	6	(99)
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2019[1]	**71**	**126**	**197**	**587**	**720**	**1,307**

(1) Columns may not add due to rounding.

The following reserve reconciliation tables are provided as an aid to the investor. The tables are based on net reserves and are consistent with our disclosure in previous years.

RECONCILIATION OF COMPANY NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

CANADA	**Light and Medium Crude Oil**			**Tight Oil**			**Heavy Crude Oil**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2018	5,828	2,979	8,807	1,067	478	1,546	2,314	891	3,205
Production	(1,013)	-	(1,013)	(189)	-	(189)	(532)	-	(532)
Technical revisions	358	(603)	(245)	16	(37)	(21)	220	(82)	138
Extensions and improved recovery	606	1,895	2,501	33	13	46	137	37	174
Acquisitions	43	17	60	-	-	-	597	232	830
Dispositions	(8)	(5)	(12)	(17)	(100)	(117)	(17)	(6)	(23)
Economic factors	(26)	1	(25)	-	-	-	(1)	(2)	(3)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2019(1)	**5,789**	**4,284**	**10,073**	**910**	**355**	**1,265**	**2,719**	**1,072**	**3,790**

CANADA	**Conventional Natural Gas**			**Coal Bed Methane**			**Shale Gas**		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2018	57,078	25,427	82,505	1,825	530	2,355	2,424	1,071	3,496
Production	(9,527)	-	(9,527)	(176)	-	(176)	(334)	-	(334)
Technical revisions	4,072	(2,654)	1,418	(280)	(113)	(393)	116	(98)	18
Extensions and improved recovery	364	1,653	2,017	-	-	-	-	-	-
Acquisitions	221	97	318	-	-	-	-	-	-
Dispositions	(23)	(10)	(34)	-	-	-	-	-	-
Economic factors	(377)	38	(339)	-	-	-	(1)	2	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2019(1)	**51,807**	**24,551**	**76,358**	**1,368**	**418**	**1,786**	**2,205**	**974**	**3,180**

CANADA	**Natural Gas Liquids**			**Total Oil Equivalent**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2018	1,769	826	2,595	21,200	9,679	30,879
Production	(342)	-	(342)	(3,748)	-	(3,748)
Technical revisions	193	(89)	103	1,439	(1,289)	150
Extensions and improved recovery	15	82	98	852	2,303	3,154
Acquisitions	7	2	10	684	268	953
Dispositions	(3)	(1)	(3)	(49)	(113)	(161)
Economic factors	(3)	3	-	(92)	8	(84)
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2019(1)	**1,638**	**823**	**2,461**	**20,286**	**10,857**	**31,143**

Freehold ROYALTIES LTD.

TOTAL	Light and Medium Crude Oil			Tight Oil			Heavy Crude Oil		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2018	5,828	2,979	8,807	1,067	478	1,546	2,314	891	3,205
Production[2]	(1,013)	-	(1,013)	(202)	-	(202)	(532)	-	(532)
Technical revisions	358	(603)	(245)	16	(37)	(21)	220	(82)	138
Extensions and improved recovery	606	1,895	2,501	33	13	46	137	37	174
Acquisitions[3]	43	17	60	84	393	477	597	232	830
Dispositions	(8)	(5)	(12)	(17)	(100)	(117)	(17)	(6)	(23)
Economic factors	(26)	1	(25)	-	-	-	(1)	(2)	(3)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2019[1]	**5,789**	**4,284**	**10,073**	**981**	**748**	**1,729**	**2,719**	**1,072**	**3,790**

TOTAL	Conventional Natural Gas			Coal Bed Methane			Shale Gas		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2018	57,078	25,427	82,505	1,825	530	2,355	2,424	1,071	3,496
Production[2]	(9,551)	-	(9,551)	(176)	-	(176)	(334)	-	(334)
Technical revisions	4,072	(2,654)	1,418	(280)	(113)	(393)	116	(98)	18
Extensions and improved recovery	364	1,653	2,017	-	-	-	-	-	-
Acquisitions[3]	373	792	1,166	-	-	-	-	-	-
Dispositions	(23)	(10)	(34)	-	-	-	-	-	-
Economic factors	(377)	38	(339)	-	-	-	(1)	2	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2019[1]	**51,936**	**25,246**	**77,182**	**1,368**	**418**	**1,786**	**2,205**	**974**	**3,180**

TOTAL	Natural Gas Liquids			Total Oil Equivalent		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2018	1,769	826	2,595	21,200	9,679	30,879
Production[2]	(342)	-	(342)	(3,765)	-	(3,765)
Technical revisions	193	(89)	103	1,439	(1,289)	150
Extensions and improved recovery	15	82	98	852	2,303	3,154
Acquisitions[3]	7	2	10	794	777	1,571
Dispositions	(3)	(1)	(3)	(49)	(113)	(161)
Economic factors	(3)	3	-	(92)	8	(84)
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2019[1]	**1,638**	**823**	**2,461**	**20,379**	**11,366**	**31,744**

(1) Columns may not add due to rounding.
(2) Includes production from Freehold's North Dakota assets from the date of acquisition in July 2019 to December 31, 2019.
(3) Includes the reserves from Freehold's North Dakota assets as at December 31, 2019 plus the production from such assets from the date of acquisition in July 2019 to December 31, 2019.

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards in the COGE Handbook.

At December 31, 2019, proved net undeveloped reserves assigned in the Trimble Report were 13.9% of the total proved net reserves assigned. 91.4% of the proved net undeveloped reserves fall within seven plays. In the Trimble Report, 100% of the proved undeveloped reserves are forecast to be drilled within the next five years. The proved undeveloped reserves in the Trimble Report relate to locations that are within actively developed resource plays and adjacent to existing production. The majority of these reserves are in unconventional resource plays where reserves are estimated from analog type curve analysis. 49.2% of the proved undeveloped reserves are forecast to be drilled in the next two years. The balance of the proved undeveloped reserves are validated based on geology and proximity to production, however, they have been scheduled beyond the first two years to correlate with the historical development drilling timeframes in individual areas. For example, in the Dodsland Viking resource play which represents approximately 47% of proved undeveloped reserves, future development is forecasted at an average of 80 locations per year over five years to match recent historical drilling results.

At December 31, 2019, probable net undeveloped reserves assigned in the Trimble Report were 14.7% of the total proved plus probable net reserves assigned. 92.1% of the probable net undeveloped reserves fall within eight plays. In the Trimble Report, 100% of the probable undeveloped reserves are forecast to be drilled within the next ten years. As with the proved undeveloped reserves, the probable undeveloped reserves in the Trimble Report relate to locations within actively developed resource plays. The majority of these reserves are in unconventional resource plays where reserves are estimated from analog type curve analysis. 30.6% of the probable undeveloped reserves are forecast to be drilled in the next two years. The balance of the probable undeveloped reserves are validated based on geology and proximity to production but are deferred to correlate with the historical development drilling timeframes in individual areas. Similarly, to proved undeveloped reserves, the probable undeveloped reserves for the Dodsland Viking resource play which represents approximately 47% of probable undeveloped reserves have been scheduled at an average of 75 locations per year from 2025 to 2029 to be consistent with recent historical drilling in the area.

The light, medium and heavy crude oil net undeveloped reserves are expected to be developed over the next several years as commodity pricing permits. Development of the undeveloped natural gas and natural gas liquids net reserves will be dependent on commodity pricing and in certain circumstances it may be three or more years until they are developed. In most cases the development of undeveloped reserves is not within the control of Freehold as it only holds a royalty interest in such reserves and therefore does not have control or influence on the development of such reserves.

The following tables set forth the proved undeveloped reserves and the probable undeveloped net reserves by product type, attributed to Freehold's assets for the years ended December 31, 2019, 2018, and 2017, based on forecast prices and costs:

INITIAL PROVED UNDEVELOPED NET RESERVES
FIRST ATTRIBUTED BY YEAR
FORECAST PRICES AND COSTS

Year	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
2017	60	-	499	17
2018	24	101	103	5
2019	394	115	181	8
Total Booked for Current Year	1,557	216	5,621	119

INITIAL PROBABLE UNDEVELOPED NET RESERVES
FIRST ATTRIBUTED BY YEAR
FORECAST PRICES AND COSTS

Year	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
2017	150	-	1,046	97
2018	60	47	243	17
2019	2,248	110	2,232	75
Total Booked for Current Year	3,261	228	5,608	236

Significant Factors or Uncertainties

The reserve and recovery information contained in the Trimble Report are only estimates and the actual production and ultimate reserves may be greater or less than the estimates prepared by Trimble.

The value of the Common Shares will depend upon, among other things, the reserves attributable to our properties. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for our properties will vary from estimates and those variations could be material. The reserve and cash flow information contained in this Statement represents estimates only. Reserves and estimated future net cash flow from our properties have been evaluated by Trimble, an independent qualified reserves evaluator. Trimble considers a number of factors and makes assumptions when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices;
- assumptions about future production levels, development costs and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- future drilling on our Royalty Lands by third parties;
- timing and amount of capital expenditures;
- marketability of production;
- future prices of oil and natural gas;
- operating costs and royalties; and
- other government levies that may be imposed over the producing life of reserves.

These factors and assumptions were based on prices at the date the evaluation was prepared. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve estimates. Many of these factors are subject to change and are beyond our control. For example, the evaluation is based in part on the assumed success of exploitation activities intended to be undertaken in future years. Actual reserves and estimated cash flows will be less than those contained in the evaluation to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation. Furthermore, cash flows may differ from those contained in the evaluation depending upon whether capital expenditures and operating costs differ from those estimated in the evaluation.

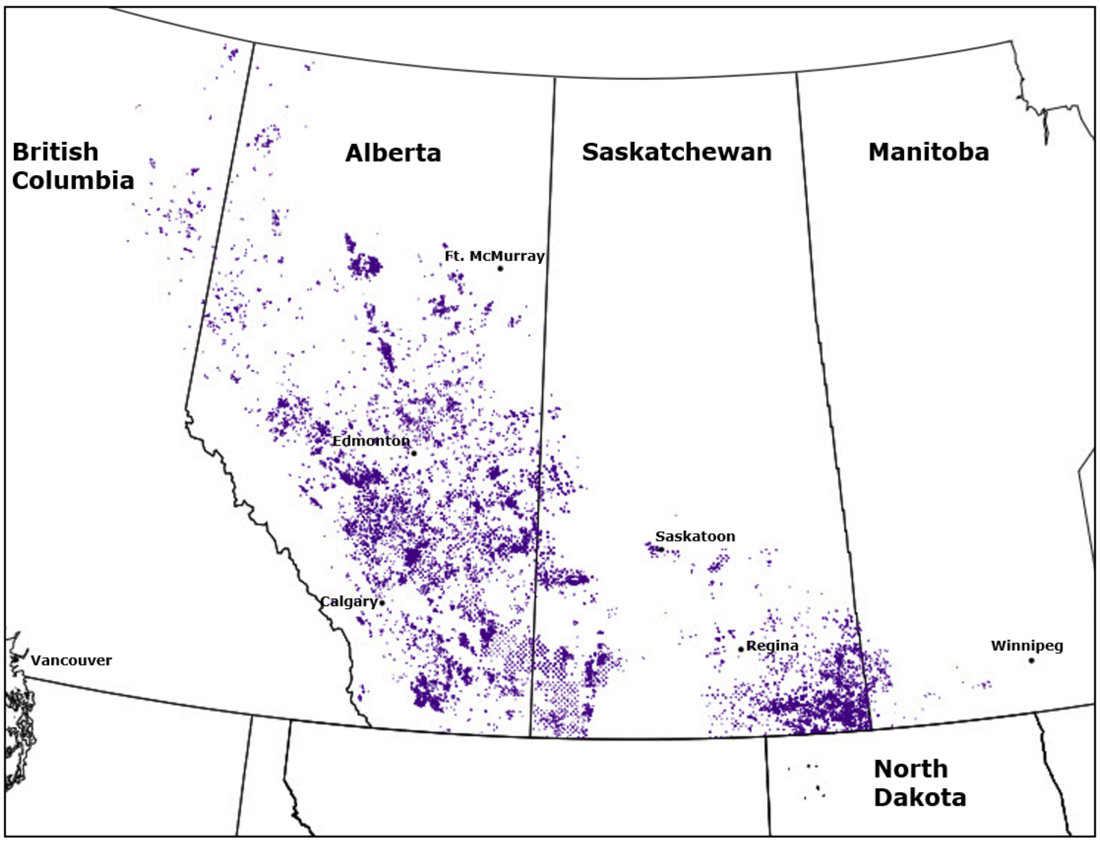
DESCRIPTION OF PROPERTIES

Freehold has oil and natural gas interests in producing and non-producing lands located in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba and Ontario and the state of North Dakota, United States encompassing approximately 6.7 million gross acres at December 31, 2019. The majority of our land (75%) is in Alberta with 18% in Saskatchewan, 4% in Ontario, 2% in British Columbia and less than 1% in Manitoba and North Dakota. We also own royalty interests in eight potash mines in Saskatchewan.

Producing lands include Crown, freehold, unitized and non-unitized oil and natural gas and potash production. The properties are operated by experienced operators. Our top ten active drillers through year-end 2019 were: Artis Exploration Ltd., Baytex Energy Corp., Bonterra Energy Corp., Crescent Point Energy Corp., Surge Energy Inc., Tamarack Valley Energy Ltd., Teine Energy Ltd., Tundra Oil & Gas, Vermilion Energy Inc., and Whitecap Resources Inc.

Our Royalty Lands consist of a large number of properties with generally small volumes per property. Many of our leases and royalty agreements allow us to take our share of oil and natural gas in-kind. As part of our risk mitigation program we carefully monitor our royalty receivables and may choose to take our royalty in-kind if there are benefits in doing so. Currently we take in-kind and market approximately 12% of our total royalty production using 30-day contracts.

Approximately 98% of our gross land holdings are royalty interests, from which we derive the majority of our income.



In the following discussion, all references to reserves are net, utilizing forecast prices and costs, before tax. All references to royalty production are net, and all references to working interest production are gross. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Royalty Interests

The unique characteristics of royalties provide royalty holders with special commercial benefits not available to the working interest owner because the royalty holder enjoys the upside potential of the property with reduced risk. A royalty interest differs significantly from a working interest in that a holder of a royalty interest is generally not responsible for, and has no obligation to contribute additional funds for any purpose, including operating or capital costs, or environmental or reclamation liabilities; whereas a holder of a working interest is liable for its share of capital, operating and environmental costs, usually in proportion to its ownership percentage, and it receives its pro rata share of revenue.

Our royalty reserves are derived from: (i) leased mineral title lands that we own and upon which we are paid lessor royalties from the lessee; (ii) royalty assumption lands which are mineral title properties owned by third parties in respect of which we are reserved royalties and which, by their terms, are expressed to be interests in land; and (iii) GORR lands leased by third parties upon which such third parties pay Freehold contractual royalties or net profits interests, which may or may not be interests in land. Mineral title and royalty assumption lands do not expire, while GORRs generally expire at the end of the lease's productive life. Mineral title lands and royalty assumption lands derived from mineral titles are held in perpetuity.

Mineral Title Lands

Royalty revenue is derived from the royalties payable to Freehold (lessor) in the form of lessor royalties through the lease documents issued to the companies (lessees) that have producing wells located thereon. In 2019, this category of land accounted for approximately 15% of our total royalty acreage and provided approximately 39% of our royalty revenue.

In Canada, we have ownership interests in mineral titles ranging from 10% to 100% and recover the applicable royalty, ranging from 10% to 22.5%, of all oil and natural gas products produced or sold from the leased lands. For example, if our interest in a mineral title property is 50% and the royalty rate applicable to the lease is 20% then we would be entitled to receive the proceeds from the sale of 10% (50% x 20%) of the oil or natural gas produced for the period.

Our mineral title lands encompass approximately 985,000, acres, of which 48% are leased and 52% are unleased. The mineral title lands also include approximately 615,000 undeveloped acres, representing potential for future development. The majority of Freehold's unleased mineral title lands are in Saskatchewan (37% in southeast Saskatchewan and 26% in southwest Saskatchewan).

In North Dakota we have ownership interests in mineral titles and recover the applicable royalty, ranging from 17% to 20%, of all oil and gas produced from the lands. Our mineral title ownership consists of approximately 750 net acres, of which 100% are leased and developed. The leases form part of eight drilling units, overlaying 11,520 gross drilling unit acres.

We also hold mineral title interests in potash, as described on page 39.

Royalty Assumption Lands

In Canada, we hold royalty interests in approximately 90,000 gross acres of land, of which approximately 18,500 acres are undeveloped. These mineral title properties, referred to as royalty assumption lands, are owned by a number of third party oil and gas companies in respect of which royalties (varying from 4.7% to 6.5%) have been reserved to Freehold. As the royalty interests with respect to the royalty assumption lands are a title royalty representing, by their terms, an interest in land, these royalties are held in perpetuity.

In 2019, this category of land accounted for approximately 1% of our total royalty acreage and provided approximately 1% of our royalty revenue.

We do not own any royalty assumption lands in the United States.

Gross Overriding Royalty Lands

In Canada, we hold GORRs in approximately 5.6 million acres, of which approximately 1.8 million acres are undeveloped. The GORRs are contractual in nature and therefore are not held in perpetuity but rather expire upon the termination of the lease(s) or agreement(s) which generally occurs when production has ceased from the subject lands. These lands consist of properties leased by a number of third party oil and gas companies in respect of which contractual royalties or net profits interests have been reserved to Freehold. In 2019, this category of land accounted for approximately 84% of our total royalty acreage and provided approximately 57% of our royalty revenue.

The granting of a GORR usually arises as a result of: (i) providing capital in exchange for granting the royalty; or (ii) converting a participating interest in a joint venture relationship into a royalty. GORRs are based on the proceeds from the sale of gross production and are generally free of any operating, capital and environmental costs.

We do not own any GORR lands in the United States.

Production Volume Royalty

Production volume royalties are arrangements under which the producer of oil and gas production sells a percentage of its volumes in exchange for a cash payment and, in certain cases, a contribution to work commitments conducted within a specific timeframe.

We have production volume royalties in Canada but not in the United States.

Description of Royalty Lands

Our royalty interests represent a geologically and geographically diverse portfolio of properties. The Manager oversees this portfolio through multi-disciplined technical teams, each managing a geographic region.

The following table summarizes, by area, our average royalty interest, net reserves and reserves value as at December 31, 2019, wells drilled, oil and natural gas production, and royalty operating income for 2019 for our Royalty Lands:

Year ended December 31, 2019		Alberta West	Saskatchewan East	North Dakota	Total
Average royalty interest (1)	(%)	2.4	2.0	1.4	2.2
Wells drilled	(gross)	249	380	12	641
Royalty operating income(2)	($000s)	59,171	73,669	1,039	133,878
Average net daily production	(boe/d)	6,807	3,364	58	10,229
Oil and NGL	(bbls/d)	2,564	3,089	48	5,701
Natural gas	(Mcf/d)	25,348	1,755	63	27,166
Net proved reserves	(Mboe)	13,179	6,580	93	19,852
Oil and NGL	(Mbbls)	4,829	5,956	72	10,857
Natural gas	(MMcf)	50,098	3,746	129	53,972
Net proved plus probable reserves	(Mboe)	19,118	10,870	602	30,590
Oil and NGL	(Mbbls	7,015	9,917	465	17,396
Natural gas	(MMcf)	72,620	5,721	824	79,164
Future Net Revenue(1)(2)					
Discounted at 10% per year	($000s)	339,300	409,796	19,527	768,622
	(% of total)	44	53	3	100

(1) Based on proved plus probable reserves and forecast prices as assigned in the Trimble Report.
(2) Excludes income from potash, interest and other.

The following table summarizes, by region, the gross royalty acreage with respect to our Royalty Lands, as at December 31, 2019:

Area	Developed Gross Acres	Undeveloped Gross Acres(1)	Total Gross Acres
Alberta West	3,381,843	168,633	5,065,476
Saskatchewan East	742,988	725,972	1,468,960
North Dakota	11,520	-	11,520
Potash	10,537	7,943	18,480
Total	4,146,888	902,548	6,564,436

(1) Undeveloped Royalty Lands are lands without producing or potentially producing wells.

Alberta West

In 2019, 39% of our gross royalty drilling occurred in the Alberta West area, which includes all of the Royalty Lands in B.C. and Alberta. These wells primarily targeted established liquids-rich gas and oil plays of the Cardium, Viking, and Mannville, as well as early continued development drilling in the newer Duvernay and Clearwater plays. In this area, over 90% of the wells targeted oil, including bitumen. Over 99% of the wells are horizontal drills. Viking drilling resulted in 89 gross wells, or 36% of gross wells drilled in the area. Cardium drilling resulted in 58 gross wells, or 23% of gross wells drilled in Alberta West. The developing Duvernay play saw 13 gross wells drilled in 2019, or 5% of Alberta West drilling, while the emerging northern Alberta Clearwater play saw 12 gross wells drilled in 2019, or 5% of Alberta West drilling.

Saskatchewan East

In 2019, 59% of Freehold's gross royalty drilling occurred in the Saskatchewan East area, which includes all of the Royalty Lands in Saskatchewan and Manitoba (with some minor acreage in Ontario). Over 98% of the wells are horizontal drills.

In 2019, 36% of the gross royalty wells drilled in the Saskatchewan East region were in the Viking oil resource play. Strong development of the Viking continues to represent core production and growth areas for Freehold.

Other significant plays of value in Saskatchewan East are the Mississippian Carbonates and Bakken plays in southeast Saskatchewan and southwest Manitoba. Together, these plays accounted for 39% of the gross royalty drilling in Saskatchewan East in 2019. Freehold continues to see the benefit of well-capitalized and active operators pursuing high netback opportunities in this area.

North Dakota

In 2019, Freehold acquired mineral title interest in approximately 750 net acres with currently 29 producing wells. The primary plays of value in North Dakota are the Bakken and Three Forks, with development occurring exclusively through horizontal drilling. In 2019, 2% of Freehold's gross royalty drilling occurred in the newly acquired North Dakota assets. Freehold has strategically positioned itself to acquire acreage under well-capitalized operators pursuing high netbacks in this area.

Potash

Our potash acreage inventory remains at approximately 18,500 gross acres in 2019. This consists of leases we have issued on our mineral title to the various operators of eight potash mines. Our leases are included in larger potash units which cover the total mine areas.

The potash mines from which we receive royalties are operated by the Mosaic Company and Nutrien Ltd. (successor resulting from the merger of Potash Corporation of Saskatchewan and Agrium Inc.). In 2019, we received approximately $1.2 million from the production of approximately ten tonnes per day of potash. As our minor interests in potash reserves are not material, a recent independent evaluation of our potash reserves has not been obtained.

Undeveloped Royalty Lands

The undeveloped Royalty Lands are lands without producing, or potentially producing, wells totalling approximately 2.4 million gross acres. Potential exists on these lands for drilling non-unitized zones within producing units, drilling or completing additional zones, infill drilling by reducing well spacing (e.g. 160 acre to 80 acre spacing in the case of an oil well), optimizing drilling locations within spacing units and horizontal drilling. If a well is drilled on lands adjacent to Royalty Lands where we own the mineral title and that well is producing from a formation in which we have an interest but that is not producing on the Royalty Lands, generally we have the right to require the lessee of the mineral title to either: (a) drill a well on an undrilled spacing unit on the Royalty Lands; (b) pay a compensatory royalty; or (c) surrender the respective formation.

Drilling Activity

Freehold receives Royalty Income from successful wells drilled on our lands. Drilling activity on the Royalty Lands is anticipated to continue to provide new sources of oil and natural gas Royalty Income in future years, with new wells, and production partially offsetting declines. Freehold is not responsible for any drilling or development activity or expenditures with respect to the Royalty Lands.

The following table summarizes the drilling activity conducted by lessees on the Royalty Lands for the two most recently completed fiscal years.

Years Ended December 31(1)	2019	2018
(gross wells)	Unitized	Non-Unitized
Oil wells	566	609
Natural gas wells	15	14
Service/other wells	58	90
Dry and abandoned wells	2	6
Total	641	719
Success rate	100%	100%

(1) Includes all drilling on properties acquired during the year.

Working Interest Properties

In Canada, we own working interests in oil and natural gas properties. Production from these properties is comprised of approximately 51% oil and NGL and 49% natural gas. Working interest production averaged 399 boe per day in 2019, down from 692 boe per day in 2018, mainly due to working interest dispositions. In 2019, we did not participate in any working interest drilling activity.

In 2020, we expect to spend a minimal amount of capital on development activities. It is anticipated $2.5 million will be directed to abandonment and reclamation activities in 2020.

We do not own any working interest properties in the United States.

OTHER OIL AND GAS INFORMATION

Oil and Natural Gas Wells

The following tables set forth, by province and state, the number and status of wells in which we have an interest as at December 31, 2019:

Royalty Lands	Natural Gas Wells	Oil Wells
Canada		
Alberta	17,589	12,650
Saskatchewan	1,618	12,330
British Columbia	223	30
Manitoba	-	466
Ontario	246	-
Canada Total	19,676	25,476
United States		
North Dakota	-	46
Total	19,676	25,522

Working Interest Properties	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	130	13.7	106	9.7	212	23.6	150	26.9
Saskatchewan	12	7.8	15	7.0	-	-	-	-
British Columbia	-	-	-	-	7	2.5	4	0.1
Manitoba	-	-	-	-	-	-	-	-
Ontario	-	-	-	-	-	-	-	-
Total(1)(2)	142	21.5	121	16.7	219	26.1	154	27.0

(1) Columns may not add due to rounding
(2) Freehold does not hold any working interests in any wells outside of Canada

Properties with No Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2019:

	Undeveloped Acres		
	Royalty Lands	Working Interest Lands	
	Gross	Gross	Net
Canada			
Alberta	1,645,638	20,080	4,217
Saskatchewan	606,295	2,279	1,700
British Columbia	37,994	2,753	83
Manitoba	28,400	-	-
Ontario	99,221	-	-
Canada Total	2,417,548	25,112	6,000
United States			
North Dakota	-	-	-
Total	2,417,548	25,112	6,000

There are no material work commitments on our undeveloped land holdings.

The area of unproved properties on which we expect our rights may expire within the next year, are approximately 117,000 gross acres.

Undeveloped lands are calculated by adding the surface area acreage covered by the leases or agreements or portions of the leases or agreements without producing or potentially producing wells. In certain limited circumstances where we have rights in different formations under the same surface area pursuant to different leases or agreements, we have included the acreage with respect to all such leases or agreements. There are no significant factors or uncertainties associated with the undeveloped land.

Tax Horizon

The corporate income tax rate applicable to 2019 was approximately 27% (2018 – 27%) and the rate for 2020 and future years is currently 25%. Taxable income as a corporation is based on total income and expenses (which will vary depending on commodity prices, production volumes, and costs), reduced by claims for both accumulated tax pools and tax pools associated with current year expenditures. Freehold had no current taxes in 2019. In the current commodity price environment, the period for which we expect there to be no current income taxes is estimated to be beyond three years in Canada. As at December 31, 2019, Freehold's tax pools were $838 million (additional information is provided in Freehold's management's discussion and analysis for the year ended December 31, 2019 which is available on SEDAR at www.sedar.com).

During the year ended December 31, 2019, Freehold received a proposal letter from the CRA wherein the CRA stated that it intends to re-assess and deny Freehold's deduction of certain non-capital losses claimed and carried forward in the tax return filed for the year ended December 31, 2015.

Freehold is currently defending its tax filing position and expects it will be successful defending its position; however, if Freehold is not successful in defending its position it could impact Freehold's timing for when it may have current taxes payable. For additional information, see "*Legal Proceedings and Regulatory Actions*".

Capital Expenditures

Future capital expenditures are anticipated to be of the types that are intended to maintain or improve production. Freehold may finance capital expenditures from additional issuances of Common Shares, borrowings, farmouts or with working capital.

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2019. The acquisition costs were for Royalty Lands. The development costs were on our working interest lands.

CANADA	($000s)
Property acquisition costs(1)	
Proved properties	25,806
Undeveloped/unproved properties	3,995
Development costs	3,721
Total (2)	33,522

(1) As classified at the time of the acquisition.
(2) We did not incur any exploration costs in 2019.

UNITED STATES	($000s)
Property acquisition costs(1)	
Proved properties	16,218
Undeveloped/unproved properties	-
Development costs	-
Total (2)	16,218

(1) As classified at the time of the acquisition.
(2) We did not incur any exploration costs in 2019.

Production Estimates

The following table sets out the volume of gross and net production estimated for the year ended December 31, 2020 in the Trimble Report, based on the forecast price case reflected in the estimate of future net revenue disclosed in the tables contained under "*Reserves Data*". No field accounts for more than 20% of the production estimate.

CANADA

	Light & Medium Crude Oil		Tight Oil		Heavy Crude Oil	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)
Proved						
Developed producing	37	2,156	-	398	93	1,236
Developed non-producing	5	5	-	-	-	1
Undeveloped	-	187	-	25	-	36
Total proved	42	2,348	-	424	93	1,272
Probable	1	175	-	22	34	88
Total proved plus probable[(1)]	42	2,523	-	446	127	1,360

	Conventional Natural Gas		Coal Bed Methane		Shale Gas	
Reserves Category	Gross (Mcf/d)	Net (Mcf/d)	Gross (Mcf/d)	Net (Mcf/d)	Gross (Mcf/d)	Net (Mcf/d)
Proved						
Developed producing	680	21,448	2	490	-	592
Developed non-producing	10	10	-	-	-	-
Undeveloped	-	934	-	-	-	282
Total proved	690	22,392	2	490	-	874
Probable	21	492	-	7	-	27
Total proved plus probable[(1)]	711	22,884	2	496	-	902

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (boe/d)	Net (boe/d)
Proved				
Developed producing	28	703	272	8,248
Developed non-producing	1	1	7	9
Undeveloped	-	27	-	477
Total proved	29	731	279	8,734
Probable	1	21	39	394
Total proved plus probable[(1)]	30	752	318	9,127

UNITED STATES

Reserves Category	Tight Oil Gross (bbls/d)	Tight Oil Net (bbls/d)	Conventional Natural Gas Gross (Mcf/d)	Conventional Natural Gas Net (Mcf/d)	Total Oil Equivalent Gross (boe/d)	Total Oil Equivalent Net (boe/d)
Proved						
Developed producing	-	56	-	103	-	73
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-
Total proved	-	56	-	103	-	73
Probable	-	41	-	74	-	54
Total proved plus probable[(1)]	-	97	-	177	-	127

TOTAL

Reserves Category	Light & Medium Crude Oil Gross (bbls/d)	Light & Medium Crude Oil Net (bbls/d)	Tight Oil Gross (bbls/d)	Tight Oil Net (bbls/d)	Heavy Crude Oil Gross (bbls/d)	Heavy Crude Oil Net (bbls/d)
Proved						
Developed producing	37	2,156	-	510	93	1,236
Developed non-producing	5	5	-	-	-	1
Undeveloped	-	187	-	25	-	36
Total proved	42	2,348	-	536	93	1,272
Probable	1	175	-	105	34	88
Total proved plus probable[(1)]	42	2,523	-	640	127	1,360

Reserves Category	Conventional Natural Gas Gross (Mcf/d)	Conventional Natural Gas Net (Mcf/d)	Coal Bed Methane Gross (Mcf/d)	Coal Bed Methane Net (Mcf/d)	Shale Gas Gross (Mcf/d)	Shale Gas Net (Mcf/d)
Proved						
Developed producing	680	21,654	2	490	-	592
Developed non-producing	10	10	-	-	-	-
Undeveloped	-	934	-	-	-	282
Total proved	690	22,597	2	490	-	874
Probable	21	641	-	7	-	27
Total proved plus probable[(1)]	711	23,238	2	496	-	902

Reserves Category	Natural Gas Liquids Gross (bbls/d)	Natural Gas Liquids Net (bbls/d)	Total Oil Equivalent Gross (boe/d)	Total Oil Equivalent Net (boe/d)
Proved				
Developed producing	28	703	272	8,394
Developed non-producing	1	1	7	9
Undeveloped	-	27	-	477
Total proved	29	731	279	8,880
Probable	1	21	39	501
Total proved plus probable[(1)]	30	752	318	9,381

(1) Columns may not add due to rounding

Production History

The following table summarizes our production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

CANADA

	2019 Quarter Ended				2018 Quarter Ended			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average daily production[1]								
Light and Medium Crude Oil[2] bbls/d)	4,008	3,709	3,790	3,800	3,784	3,771	4,071	4,114
Heavy Crude Oil (bbls/d)	1,178	1,261	1,084	1,057	1,349	1,259	1,279	1,431
Conventional Natural Gas[3] (Mcf/d)	27,786	27,609	28,768	28,938	28,776	30,331	32,488	33,206
NGL (bbls/d)	827	773	995	947	1,000	917	956	922
Combined (boe/d)	10,645	10,345	10,664	10,627	10,929	11,002	11,721	12,002
Average price realized								
Light and Medium Crude Oil[2] ($/bbl)	66.03	62.85	70.28	61.59	41.09	75.91	71.88	64.22
Heavy Crude Oil ($/bbl)	53.51	54.79	61.15	50.88	17.09	54.44	52.98	37.87
Conventional Natural Gas[3] ($/Mcf)	2.13	0.87	0.71	2.18	1.54	1.03	0.83	1.62
NGL ($/bbl)	30.66	27.78	29.60	36.76	32.96	46.43	47.85	45.56
Combined ($/boe)	36.69	33.62	35.88	36.29	23.40	38.95	36.96	34.52
Royalty expense[4]								
Light and Medium Crude Oil[2] ($/bbl)	0.09	0.09	0.11	0.02	0.12	0.13	0.28	0.16
Heavy Crude Oil ($/bbl)	0.01	0.33	0.54	0.51	0.26	1.56	0.52	0.74
Conventional Natural Gas[3] ($/Mcf)	(0.01)	0.02	0.00	0.01	(0.02)	(0.01)	-	-
NGL ($/bbl)	0.19	0.29	0.14	0.09	0.34	0.34	0.46	0.64
Combined ($/boe)	0.02	0.15	0.11	0.09	0.06	0.23	0.18	0.19
Operating expenses ($/boe)[5]								
Light and Medium Crude Oil[2] ($/bbl)	0.50	0.66	0.63	0.53	1.33	0.53	1.11	1.55
Heavy Crude Oil ($/bbl)	3.96	3.63	4.44	5.92	3.87	5.39	6.30	4.37
Conventional Natural Gas[3] ($/Mcf)	0.16	0.08	0.12	0.07	0.15	0.15	0.14	0.10
NGL ($/bbl)	0.77	0.46	0.57	0.36	0.62	0.62	0.79	0.62
Combined ($/boe)	1.08	0.93	1.05	1.01	1.38	1.35	1.53	1.39
Netback received[6][7]								
Light and Medium Crude Oil[2] ($/bbl)	65.44	62.10	69.54	61.04	39.64	75.25	70.49	62.51
Heavy Crude Oil ($/bbl)	31.11	50.83	56.17	44.45	12.96	47.49	46.16	32.76
Conventional Natural Gas[3] ($/Mcf)	1.98	0.77	0.59	2.10	1.41	0.87	0.69	1.52
NGL ($/bbl)	29.70	27.03	28.89	36.31	32.00	45.19	46.60	44.30
Combined ($/boe)	35.58	32.53	34.72	35.19	21.96	37.37	35.25	32.94

(1) Calculated by adding net production from our Royalty Lands and gross production from our working interest properties (except certain royalty interests owned by Freehold associated with the working interest properties have been deducted from the gross production of the working interest properties as such production is reflected in the net production from the Royalty Lands in the above table).
(2) Includes an immaterial amount of production from tight oil reserves.
(3) Includes an immaterial amount of production from coal bed methane and shale gas reserves.
(4) Royalty expense includes all Crown charges and royalty payments to third parties.
(5) Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Overhead recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.
(6) Netbacks are calculated by subtracting royalty expenses and operating costs from revenues.
(7) Excludes income from potash, interest and other.

UNITED STATES[1]

	2019 Quarter Ended				2018 Quarter Ended			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average daily production[2]								
Tight Oil bbls/d)	86	104	-	-	-	-	-	-
Conventional Natural Gas (Mcf/d)	55	137	-	-	-	-	-	-
NGL ($/bbl)	-	-						
Combined (boe/d)	95	137	-	-	-	-	-	-
Average price realized								
Tight Oil ($/bbl)	81.65	63.03	-	-	-	-	-	-
Conventional Natural Gas ($/Mcf)	4.32	3.75	-	-	-	-	-	-
NGL ($/bbl)	13.51	-	-	-	-	-	-	-
Combined ($/boe)	76.02	53.34	-	-	-	-	-	-
Royalty expense[3]								
Tight Oil ($/bbl)	29.97	6.59	-	-	-	-	-	-
Conventional Natural Gas ($/Mcf)	-	-	-	-	-	-	-	-
NGL ($/bbl)	-	-	-	-	-	-	-	-
Combined ($/boe)	26.96	5.02	-	-	-	-	-	-
Operating expenses ($/boe)[4]								
Tight Oil ($/bbl)	-	-	-	-	-	-	-	-
Conventional Natural Gas ($/Mcf)	-	-	-	-	-	-	-	-
NGL ($/bbl)	-	-	-	-	-	-	-	-
Combined ($/boe)	-	-	-	-	-	-	-	-
Netback received[5]								
Tight Oil ($/bbl)	51.68	56.44	-	-	-	-	-	-
Conventional Natural Gas ($/Mcf)	4.32	-	-	-	-	-	-	-
NGL ($/bbl)	13.51	-	-	-	-	-	-	-
Combined ($/boe)	49.06	48.23	-	-	-	-	-	-

(1) Denominated in Canadian dollars.
(2) Calculated by adding net production from our Royalty Lands and gross production from our working interest properties (except certain royalty interests owned by Freehold associated with the working interest properties have been deducted from the gross production of the working interest properties as such production is reflected in the net production from the Royalty Lands in the above table).
(3) Royalty expense includes all royalty payments to federal and state governments and third parties.
(4) Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Overhead recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.
(5) Netbacks are calculated by subtracting royalty expenses and operating costs from revenues.

The following table summarizes our average daily production from important regions or fields for the year ended December 31, 2019:

	Light and Medium Crude Oil(2) (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas(3) (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
Canada Royalty Lands(1)					
Alberta West	1,144	657	25,348	780	6,807
Saskatchewan East	2,622	377	1,756	73	3,364
Canada Total	3,766	1,034	27,104	853	10,171
United States Royalty Lands					
North Dakota	48	-	62	-	58
Working Interest Properties(4)	39	133	1,167	32	399
Total	3,853	1,167	28,333	885	10,628

(1) Production from the Royalty Lands is presented on a net basis.
(2) Includes an immaterial amount of production from tight oil reserves.
(3) Includes an immaterial amount of production from coal bed methane and shale gas reserves.
(4) All working interest properties are located in Canada.

Environmental Obligations

As a royalty owner, Freehold does not directly operate any of our royalty assets. Royalty owners are not generally responsible for operating or capital costs, or environmental or reclamation liabilities. The projects on which we receive royalty revenue are owned and operated by independent oil and gas companies of which many are publicly listed (commonly referred to as our "Third Party Operators" or "Lessees"). Our royalty payors are represented by some of the largest and most recognized Third Party Operators in the Canadian and U.S. oil and gas industry. These companies operate within the Canadian and U.S. regulatory frameworks – which are two of the strongest in the world.

Freehold also owns working interests in oil and natural gas properties. We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of our working interest properties upon abandonment. In 2019, our working interest assets represented less than 1% of our total operating income and approximately 4% of total production. Environment, health and safety falls under the responsibility of Rife as Manager of Freehold's assets. Rife has a comprehensive program that includes policies and procedures designed to protect the environment and the health and safety of its employees, safety liabilities through pre-acquisition assessments, periodic assessments, and audits. Environmental, health and safety exposures are tracked and addressed with short and long term initiatives.

Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs

We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of our working interest properties upon abandonment. We have no reclamation responsibilities with respect to our Royalty Lands as these are the responsibility of the working interest owners. Ongoing environmental obligations are funded from operations.

For the purposes of estimating Reserves Data, abandonment, decommissioning and reclamation costs for all wells (both existing and undrilled wells and active and inactive wells) have been taken into account whether or not such wells have been attributed reserves. In addition, abandonment, decommissioning and reclamation of pipelines and facilities were also taken into account for the purposes of estimating Reserves Data. The undiscounted amount of abandonment and reclamation costs reflected in the estimates of future net revenue associated with our proved reserves and proved plus probable reserves is approximately $9.4 million and $10.1 million, respectively.

Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment and reclamation cost history.

Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties can be found in Freehold's consolidated financial statements for the year ended December 31, 2019 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

BORROWINGS

Freehold has extendible revolving credit facilities with a total commitment of $180 million consisting of a $165 million syndicated facility and a $15 million operating facility.

The current maturity date of the credit facilities is May 31, 2022. Freehold may annually request an extension of the current maturity date, subject to approval by the banks. Following the granting of any extension, the term to maturity of the credit facilities may not exceed three years.

Borrowings under the credit facilities bear interest at the bank's prime lending rate, bankers' acceptance rates or LIBOR rates plus applicable margins. The applicable margin is dependent on the ratio of Freehold's debt to EBITDA on royalty interest properties (calculated as earnings on royalty interest properties before non-cash charges including, but not limited to, interest, taxes, depletion and depreciation and amortization). Standby fees are charged on the undrawn amounts of the facilities, also dependent on this ratio.

We are required to comply with various covenants under the credit facilities including two financial covenants: (1) the ratio of our debt to EBITDA on royalty interest properties shall not exceed 3.5 to 1.0 and (2) the ratio of our debt to capitalization (the aggregate of debt and shareholders' equity) shall not exceed 55%. Pursuant to the terms of our credit facilities, we are restricted from paying dividends if we would be in default under the facilities.

The credit facilities are secured with $400 million first charge demand debentures over all of Freehold's assets.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas industry are subject to extensive controls and regulations imposed by various levels of government 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.

The Corporation holds interests in crude oil and natural gas properties, along with related assets, primarily in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba in Canada. The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Corporation's and its royalty payor'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.

In addition, the Corporation also holds interests in crude oil and natural gas properties, along with related assets, in the state of North Dakota in the United States. The Corporation's assets and operations in the United States are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Corporation's and its royalty payor'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; (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 state 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. Given that the Corporation's interests in the United States represent an immaterial portion of the Corporation's total interests (less than 0.5% based on the future net revenue of the Corporation's total proved plus probable reserves are associated with the Corporation's interests in the United States) a more detailed discussion of the pertinent conditions and regulations that impact the crude oil and natural gas industry in North Dakota has not been included in this AIF.

Pricing and Marketing

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic 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 and cost of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

Negotiations between buyers and sellers determine the price of natural gas sold in intra-provincial, interprovincial, inter-state 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 and cost 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. As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial, inter-state 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, costs of transportation, fractionation costs, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Exports of crude oil, natural gas and NGLs from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("**Cabinet**") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or 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 twenty years for quantities not exceeding 30,000 m^3 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 CER and the Canadian federal government. The Corporation 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 United States 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

Pipelines

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 jurisdictions 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. The Canadian federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of such 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 through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of 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 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC 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. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to the Federal Court of Appeal decision will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019, and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two of the Indigenous applicants subsequently withdrew from the litigation after reaching a deal with Trans Mountain Pipeline. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four applicants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada-United States Border remains dependant on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGL products in excess of 12,500 metric tones to or from British Columbia's north coast. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents; however, nothing has been publicly announced indicating the fate of the program, or whether any of the contracts have been assigned to industry proponents. On February 11, 2010, the Government of Alberta announced that it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

In February 2020, the federal government announced that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits, following two derailments that led to fires and oil spills in Saskatchewan. These reduced speed limits will remain in effect until April 1, 2020.

Natural Gas

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. 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. Companies without firm access 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).

Required repairs or upgrades to 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. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network, (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and United States Natural Gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, 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. Nonetheless, 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. Pre-construction activities began in November 2018, with a planned completion target of 2025. On February 19, 2020, the British Columbia Environmental Assessment Office (the "**EAO**") directed Coastal GasLink to re-engage and consult further with Unist'ot'en, one of the Wet'suwet'en clans opposed to the pipeline route, regarding the impacts of the pipeline on a nearby healing centre. The EAO prescribed a 30-day timeline for the completion of these consultations and CGL is permitted to continue pre-construction work in the relevant area.

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd. ("**Pieridae**"), would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

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*, as amended effective October 1 2019, the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 bbls/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint venturers may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbls/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for December 2019, January 2020 and February 2020 is set at 3.81 million bbls/d.

The Government of Alberta introduced certain policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Curtailment volumes affect sixteen of over 300 producers in Alberta. The *Curtailment Rules* are set to be repealed by December 31, 2020.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement, or "**CUSMA**". Legislative bodies in the three signatory countries must ratify the USMCA before it comes into force. Mexico's senate ratified the USMCA in June 2019. In late December 2019, the United States' House of Representatives approved the USMCA, and the USMCA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 to ratify the USMCA. According to Bill C-4, the USMCA will come into force two months after the House of Commons and the Senate pass Bill C-4. Until then, NAFTA remains the North American trade agreement currently in force. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final version 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.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of 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.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced. It is possible that the USMCA will come into force before the Government of Alberta's curtailment order is set to be repealed by the end of 2020.

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.

Other Trade Agreements

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 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union.

Canada and ten other countries have agreed on the 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. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam, 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 (i.e. the Crown), predominantly own the mineral rights to crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Oil and natural gas leases with provincial governments generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop minerals, including oil and gas, it is necessary for the mineral estate owner(s) to have access to the surface estate. Under common law in Canada, the mineral estate is considered the "dominant" estate with the right to extract minerals subject to reasonable use of the surface. Each province and state has developed and adopted their own statutes that operators must follow both prior to drilling and following drilling, including notification requirements and the provision of compensation for lost land use and surface damages. The surface rights required for pipelines and facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Additionally, the provinces of Alberta and British Columbia have shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

The private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, oil and natural gas activities conducted on Indigenous reserve lands in Canada were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the "**1995 Regulations**"). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. Freehold does not have interests on Indigenous reserve lands.

Royalties and Incentives

General

In addition to federal regulation, each province in Canada has legislation and regulations that govern royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of hydrocarbon production. Royalties payable on production from lands other than Crown lands in Canada are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain taxes and royalties. Royalties from production on Crown lands in Canada are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced.

From time to time the federal and provincial governments in Canada create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays, royalty tax credits and other tax incentives that are generally introduced to encourage specific types of exploration and development activity.

The federal government in Canada also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies, of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totalling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. The *Royalty Guarantee Act (Alberta),* came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry’s average drilling and completion costs as determined by the Alberta Energy Regulator (the "**AER**") on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from

Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

British Columbia

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGLs in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGLs and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGLs and condensates, the royalty rate is fixed at 20%.

The royalties payable by each producer will therefore vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale from $1.25 to $4.94 per hectare, depending on the total number of hectares owned by the entity.

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by entities focused on crude oil and natural gas operations. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Additionally, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned regardless of whether or not there is production from the lands.

In addition to such surcharges and taxes, the Crown royalty rate payable in respect of crude oil, depends on a number of variables including, the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and is subject to applicable deductions.

The amount payable as a Crown royalty in respect of production of natural gas and NGLs is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells.

For production from freehold lands, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor. Depending on the classification of the petroleum substance produced, this subtraction factor may range between 6.9 and 12.5, however, in certain circumstances, the minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets.

Manitoba

In Manitoba, the Crown owns only approximately 20% of the crude oil and natural gas rights in the province, with the remainder being freehold lands. The royalty amount payable on crude oil produced from Crown lands depends on the classification of the crude oil produced. Royalty rates on crude oil are calculated on a sliding scale with a range of 0% to approximately 42.8% and based on the monthly crude oil production from a spacing unit, or crude oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on crude oil produced from Crown lands is calculated based on the amount of crude oil production allocated to a spacing unit in accordance with the applicable regulations. As such, the royalty payable by producers will vary depending on the underlying characteristics of the producer's assets.

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

The Government of Manitoba maintains a Drilling Incentive Program (the "**MB Incentive Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The MB Incentive Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no royalties are payable until the holiday oil volume has been produced. The MB Incentive Program consists of benefits that are specific to certain vertical, exploration, and deep wells, as well as wells undergoing major workovers, wells for solution gas, and wells converted to injection wells. The MB Incentive Program was extended without alteration in April, 2019 to December 31, 2020.

Producers of crude oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on crude oil is calculated on a sliding scale between 0% and approximately 40% based on the monthly production volume and the classification of crude oil as old oil, new oil, third-tier oil, and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces and the state of North Dakota are required to pay freehold mineral taxes or production/extraction taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

Where oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers, and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

Regulatory Authorities and Environmental Regulation

General

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to international conventions and national, provincial, state, territorial and municipal laws, all of which are subject to review and revision from time to time. Environmental legislation provides 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, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions including carbon dioxide equivalents ("**CO2e**"), may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Canada

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. 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 August 28, 2019, with the passing of Bill C-69, the CERA and the *Impact Assessment Act* ("**IAA**") came into force and the NEB Act and the *Canadian Environmental Assessment Act*, *2012* were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency.

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions will fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

Designated projects will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The impact assessment must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75km of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

The federal government of Canada has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government of Canada has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested.

On May 12, 2017, the federal government of Canada introduced Bill C-48 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 passed Bill C-48 as the *Oil Tanker Moratorium Act* which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53′00′′ north latitude and west of 126°38′36′′ west longitude) and, as a result, may negatively impact 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 legislation 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 the Alberta Ministry of 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 the Alberta Ministry of Environment and Parks, the Alberta Ministry of Energy, 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. These regional plans may affect further development and operations in such regions.

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 British Columbia Oil and Gas Commission (the "**BC Commission**") 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 BC Commission 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 passed *Bill 51 – 2018: Environmental Assessment Act in* late 2018, which will replace the environmental assessment regime that has been in place since 2002. The updated *Environmental Assessment Act* is not yet in force. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process. The new environmental assessment process aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building, in alignment with British Columbia's recent passage of Bill 41, which affirmed and adopted the United Nations Declaration on the Rights of Indigenous Peoples. Simultaneously with the enactment of the *Environmental Assessment Act*, the British Columbia Government enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project. However, many details of the new assessment process remain unknown, but the British Columbia Government has released a proposed timetable for the release of supplementary and informational materials through 2020.

In 2018, the British Columbia Government proposed amendments to the BC EMA that would see new heavy oil imports, whether by rail, expanded pipeline, or otherwise, managed through a discretionary permitting process (the "**Proposed Amendments**"). The Proposed Amendments would directly affect the transport of heavy oil blends across British Columbia to tidewater through the Trans Mountain Pipeline. In its unanimous decision, the *Reference Re Environmental Management Act (British Columbia)* delivered May 24, 2019; the British Columbia Court of Appeal held that the Proposed Amendments are unconstitutional. The Supreme Court of Canada heard British Columbia's appeal on January 16, 2020, and found that, constitutionally, the British Columbia Government does not have the jurisdiction to make the Proposed Amendments. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. On January 29, 2020, the Government of British Columbia acknowledged that Canada's highest court has ruled in support of the Trans Mountain Pipeline expansion proceeding, and indicated that the Government of British Columbia would not initiate further challenges against the Trans Mountain Pipeline.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the "**SKOGCA**") is the act governing the regulation of resource development operations in the province, along with *The Oil and Gas Conservation Regulations, 2012* (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). The aim of the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. The Government of Saskatchewan has implemented a number of operational requirements, including an increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex Database.

Manitoba

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

Pursuant to the MBOGA, the Government of Manitoba recently launched an online database for the publication of missing royalty owner applications, to help alleviate uncertainty for royalty owners and payors. A person may make an application on behalf of a royalty owner, when the identity or whereabouts of a royalty owner in a tract or spacing unit cannot be ascertained, for an order authorizing the exploration for oil and natural gas.

Liability Management Rating Program

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**"). If a licensee's 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 licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). 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.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect the Corporation's ability to obtain or transfer licenses.

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.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in *Redwater Energy Corporation (Re)* ("**Redwater**"), 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 Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In Response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee 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 transfers 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. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

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% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission System. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural 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 though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets.

British Columbia

Similar to Alberta, the BC Commission 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 BC Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (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.

As a result of certain amendments to the OGAA, on April 1, 2019 a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. 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 are required 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 OGAA permits the BC Commission to impose more than one levy in a given calendar year.

Effective May 31, 2019, the *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") establishes the legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BC Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in an annual work plan.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR below 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

Manitoba

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

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada. The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow.

Canada

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, including Canada, 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 December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% 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/tonne in 2018, increasing annually until it reaches $50/tonne in 2022. This system applies 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. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

Six provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories. The federal fuel charge regime took effect in Saskatchewan, Manitoba, Ontario, and New Brunswick on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal carbon-pricing regime took effect in Alberta on January 1, 2020. Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada and the Court is set to hear the appeals in March 2020. On February 24, 2020, the Alberta Court of Appeal determined that the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals or, relatedly, whether those scheduled hearings will be delayed as a result. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled hearings, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

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, and came into force on 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 natural 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.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators so as to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. 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.

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to $30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed *Technology Innovation and Emissions Reduction* ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

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 through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. 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% below 2007 levels by 2050.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30/tonne. However, the Government raised the carbon tax to $35/tonne in April 2018, and subsequently raised it to $40/tonne on April 1, 2019. The Government of British Columbia intends to continue raising its carbon tax in $5 increments until it reaches $50/tonne in 2021.

*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% 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% renewable content requirement in natural gas by 2030; iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; iv) investing in the electrification of crude oil and natural gas production; v) reducing 45% of methane emissions associated with natural gas production; and vi) incentivizing the adoption of zero-emissions vehicles. The 2019 provincial budget provided $902 million over three years to support CleanBC, including electric vehicle rebates, incentives for making homes and businesses more energy efficient, and an enhanced climate action tax credit. On January 16, 2019, the BC Commission 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 came into effect on January 1, 2020.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. Subsequently, the Government released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

The MRGGA, which is partially compliant with the federal emissions trading system, was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full in December 18, 2018, establishing the framework of an output-based emissions management framework.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, the *Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to achieve 4.5 million tonne CO2e reduction in emissions by 2025, and a total reduction of 38.2 million tonnes CO2e between 2020 and 2030.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the Province's progress on goals set out under *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy*. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

On October 1, 2019, *Bill 147 – An Act to amend The Oil and Gas Conservation Act*, was proclaimed into force that, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

Manitoba

On March 15, 2018, Manitoba unveiled the *Climate and Green Plan Implementation Act*. The Act includes five separate acts that cover a variety of environmental and economic areas including climate change, greenhouse gas emissions, water protection, income tax and fuel tax related measures. The Climate and Green Plan removes the previous $25/tonne provincial tax on carbon. On June 11, 2019, the Government of Manitoba set its GHG emission reduction target at one megatonne for the 2018-2022 period. The announcement makes Manitoba the first jurisdiction in North America to establish a set emissions reductions goal in rolling five-year periods.

RISK FACTORS

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

Weakness and Volatility in the Oil and Natural Gas Industry

Market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Risk Factors – Political Uncertainty*". These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural 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. See "*Risk Factors –Royalties and Incentives*", "*Risk Factors – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors – Climate Change Regulation*". In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

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. See "*Risk Factors – Reserves Estimates*". Any decrease in value of the Corporation may reduce its borrowing capacity which, could result in the Corporation not being able to extend the term of the facilities, at the existing level. See "*Risk Factors – Credit Facilities*". 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 natural 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 natural 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. See "*Risk Factors – Additional Funding Requirements*".

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation and its partners and royalty payors ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. See "*Industry Conditions – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the Oil and natural gas Industry*". 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 processing and storage 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 and its partners and royalty payors.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation, its partners and royalty payor'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 a reduction in the volumes and the value of the Corporation's reserves. The Corporation and its partners and royalty payors might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

See "*Industry Conditions – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Reliance on Third Parties

The Corporation relies on other companies drilling and producing from lands in which the Corporation has a royalty interest. The Corporation has very limited ability to exercise influence over the decision of companies to drill and produce from such lands in which the Corporation has a royalty interest. The Corporation's return on lands in which it has a royalty interest depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the capital expenditure budgets and financial resources of the operators who have a working interest in such lands, the ability to efficiently produce the resources from such lands and commodity prices.

In addition, due to the volatile commodity prices, many companies, including companies that may have a working interest in the lands in which the Corporation has a royalty interest, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. In addition, weak commodity prices and/or governmental production curtailment might result in companies choosing to defer capital spending or shutting-in existing production. See "*Industry Conditions – Curtailment*". Any reduction in the drilling and production from lands in which the Corporation has a royalty interest will negatively affect the Corporation's cash flows and financial results.

Any financial difficulty of companies which have assets in which the Corporation has a royalty interest may affect the Corporation's ability to collect royalty payments, especially if such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency. In addition, to the extent any companies who have assets in which the Corporation has a royalty interest go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency it is possible that the Corporation's royalty interest may not be (or may not be recognized as) an interest in land and as such the Corporation's royalty interest may not survive such bankruptcy or insolvency proceedings.

Freehold and Canpar Shared Mineral Title Ownership

Freehold and Canpar share mineral title ownership rights in a substantial land base in western Canada. Generally, Canpar owns mineral rights that were below the deepest producing formation at the time that Freehold was created in 1996, and Freehold holds the balance of the mineral rights. Freehold is not the legal registered owner of such mineral rights as Canpar holds these rights in trust for Freehold and receives the royalty payments in respect of such mineral rights on behalf of Freehold. Canpar currently holds mineral rights in trust for Freehold that represent approximately 10% of Freehold's total royalty revenue in 2019. As both Freehold and Canpar are both currently managed by Rife, collection of the royal payments that Canpar receives in trust for Freehold is managed by Rife. If the Management Agreement was terminated or Canpar was sold to a third party, although Canpar or the third party would still be obligated to hold such royalty payments in trust for Freehold, collection of such royalty payments may be delayed or be more challenging.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual or other 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, generally, and of the Corporation's 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 a portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Take-in-Kind

All agreements that the Corporation has entered into that create a new royalty stipulate that the royalty interest so acquired by the Corporation is an interest in land and as such is separate and distinct from the interest of the royalty payor. In addition, all of these new royalty agreements provide the Corporation with the right, but not the obligation, to take its share of production in kind rather than have the royalty payor sell the Corporation's royalty production on behalf of the Corporation as agent for the Corporation. These provisions serve to mitigate the counter party risk attributable to any financial difficulty of the royalty payors under these agreements. The previously discussed provisions may not exist in certain of the royalty agreements previously entered into by other royalty recipients who subsequently sold their respective interest as a royalty recipient to the Corporation.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability, and the ability of its partners and royalty payors 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 and its partners and royalty payors 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 or its partners and royalty payors 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 or 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, effective maintenance operations and the development of enhanced oil recovery technologies 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 and the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour gas in certain areas. An unintentional leak of sour 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 geological and seismic risks, 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. See "*Risk Factors – Insurance*". In either event, the Corporation could incur significant costs.

Operational Dependence

Other companies operate most 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 a working interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results. See "*Industry Conditions – Liability Management Rating Program*".

Title to and Right to Produce from Assets

The Corporation's actual title to and interest in its properties, and its right to produce and sell the oil and natural gas therefrom, may vary from the Corporation's records. In addition, there may be valid legal challenges or legislative changes that affect the Corporation's title to and right to produce from its oil and natural gas properties, which could impair the Corporation's activities and result in a reduction of the revenue received by the Corporation.

If a defect exists in the chain of title or in the Corporation's right to produce, or a legal challenge or legislative change arises, it is possible that the Corporation may lose all, or a portion of, the properties to which the title defect relates and/or its right to produce from such properties. This may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. Also, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses and assets 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 the resources 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, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In late January 2020, the Canadian Parliament tabled Bill C-4, which once proclaimed into force, will ratify the USMCA. The USMCA is expected to fully replace NAFTA two months after Bill C-4 comes into force. See "*Industry Conditions - The North American Trade Agreement and Other Trade Agreements*". The U.S. 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 U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. 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 natural gas companies, including the Corporation.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. 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. Conflict and political uncertainty also continues to progress in the Middle East. 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 and its partners' and royalty payors' ability to market its products internationally, increase costs for goods and services required for the Corporation's and its partners' and royalty payors' operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

A change in federal, state, provincial or municipal governments in Canada or the United States, as applicable, may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. In January 2020, the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction where the Corporation is active. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The federal Government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

Project Risks

The ability of the Corporation and its royalty payors to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement and severe weather events, including fire, drought and flooding;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour;
- political uncertainty;
- environmental and indigenous activism that potentially results in delays or cancellations of projects; 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.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation and its partners and royalty payors delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation and its partners and royalty payors can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to Cabinet's approval of the Trans Mountain Pipeline expansion, and construction on the pipeline expansion is underway. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Corporation's inability to realize the full economic potential of its products or in a reduction of the price offered for the Corporation's production. 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 have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is 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 material adverse effect on the Corporation's ability to process its production and deliver the same to market. 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.

Reserves Estimates

There are numerous uncertainties inherent in estimating reserves, and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) 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 properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

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

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

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

Industry Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. In particular, the Corporation competes with other companies for the acquisition of royalty interests in oil and gas properties. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation and who may have lower costs of, and better access to, capital. The Corporation's ability to increase its reserves in the future will depend partially on its and its partners' and royalty payors' ability to explore and develop its present properties, but will primarily depend on its ability to acquire royalty interests in suitable producing properties or properties with future reserve or resource potential. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to implement and benefit from technological advantages. 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 also 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

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 systems 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. Advancements in energy efficient products have a similar effect on the demand for oil and natural 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 flow by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Regulatory

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 and its partner's and royalty payor's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*", "*Industry Conditions – Curtailment*" and "*Risk Factors – Liability Management*".

In order to conduct oil and natural gas operations, the Corporation and its partners' and royalty payors' will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation and its partners' and royalty payors' 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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Royalty Regimes

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 or its partners' or royalty payors' projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's or its partners' or royalty payors' operations, less economic. See "*Industry Conditions - Royalties and Incentives*".

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's and its partners' and royalty payors' 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 and its partners and royalty payors are ultimately able to produce from its reserves.

Disposal of Fluids Used in Operations

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, state 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 costs of compliance for the Corporation or the Corporation's royalty payors.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural 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. New environmental legislation at the federal, provincial and state levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

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.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Any 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 operating expenses of the Corporation or the Corporation's royalty payors, each of which may have a material adverse effect on the Corporation's royalties collected 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.

Liability Management

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the AB LMR Program administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to the Corporation's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program 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 natural 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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Third-party operations and activities associated with the Corporation's royalty payors emit greenhouse gases which may require parties leasing and/or operating the royalty properties to comply with federal, state and/or provincial greenhouse gas emissions legislation. 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 to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with greenhouse gas related regulations may have a material adverse effect on Freehold's business, financial condition, results of operations and prospects.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. See "*Risk Factors – Seasonality*". In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Corporation its partners and royalty payors to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, the Corporation, its partners and royalty payors may not be able to, or will incur greater costs to, carry out hydraulic fracturing or waterflood operations.

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Corporation, its partners and royalty payor's ability to access their respective properties and cause operational difficulties, including significant downtime and damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions.

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, which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Given the evolving nature of climate change policy and the control of greenhouse gases and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses (or the operating expenses of its royalty payors), and, in the long-term, potentially reducing the demand for oil and natural gas production, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or requiring asset impairments for financial statement purposes. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*", "*Risk Factors – Reputational Risk Associated with the Corporation's Operations*" and "*Risk Factors – Changing Investor Sentiment*".

Variations in Foreign Exchange Rates and Interest Rates

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

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its activities, and if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the Common Shares of the Corporation.

Substantial Capital Requirements

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

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

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

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and natural 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 natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, 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 suitable financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is determined by the Corporation and its lenders. The Corporation is required to comply with non-financial and financial covenants under its credit facility 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. 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, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The impact of the Supreme Court of Canada's decision in the Redwater case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has not yet been determined but could affect lending practices as secured creditors will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

If the Corporation's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant, 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 its credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

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

Hedging

Although the Corporation has never hedged, from time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

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

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

Availability and Cost of Material and Equipment

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation's and its partners' and royalty payors' exploration, development and operating activities.

The Corporation requires a Skilled Workforce

The operations and management of the Corporation require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals by the Manager. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure by the Manager to implement the Corporation's business plans. The Manager competes with other companies in the oil and natural gas industry, as well as other industries, for this skilled workforce. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. If the Manager is unable to: (i) retain current employees; and/or (ii) recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Manager and correspondingly the Corporation could experience increased costs to retain and recruit these professionals.

If the Management Agreement is terminated, the Manager would cease to manage the operations of the Corporation and the Corporation would be required to ensure that it has sufficient staff to continue to carry on its business. There is no certainty that the Corporation would be able to hire or retain the necessary and appropriate staff to continue to manage the operations of the Corporation upon any termination of the Management Agreement. Any failure of the Corporation to recruit and retain the necessary and appropriate staff upon any termination of the Management Agreement, may negatively impact the Corporation.

Diluent Supply

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent, or a restriction in access to diluent, may cause its price to increase, increasing the cost to transport heavy oil and bitumen to market. An increase to the cost of bringing heavy oil and bitumen to market may increase the Corporation's and its partners' and royalty payors' overall operating cost and result in decreased net revenues, negatively impacting the overall profitability of the Corporation's heavy oil and bitumen assets.

Insurance

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

Geopolitical Risks

Political changes in North America and political instability in the Middle East and elsewhere may cause disruptions in the supply of oil that affects 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 parties in power, may 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.

Non-Governmental Organizations

The oil and natural gas exploration, development and operating activities conducted by the Corporation and its partners and royalty payors may, at times, be subject to public opposition. Such public opposition could expose the Corporation and its partners and royalty payors to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial, state or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that the Corporation and its partners and royalty payors will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Corporation and its partners and royalty payors to incur significant and unanticipated capital and operating expenditures.

Reputational Risk Associated with the Corporation's Operations

The Corporation's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment toward, or in respect of, the Corporation's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Corporation operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Corporation's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Similarly, our reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by our, or our partners' and royalty payors' operations. In addition, if we develop a reputation of having an unsafe work site, it may impact our ability to attract and retain the necessary skilled employees and consultants to operate our business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact our reputation. See "*Risk Factors – Climate Change*".

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard our reputation. Damage to our reputation could result in negative investor sentiment towards Freehold, which may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our securities.

Changing Investor Sentiment

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during transportation and indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural 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 natural 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 and management 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 natural 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 Corporation's securities even if the Corporation's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Corporation's asset which may result in an impairment charge.

Dilution

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

Management of Growth

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

Expiration of Licenses and Leases

The Corporation's working interest 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 and the associated abandonment and reclamation obligations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

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

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

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

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation 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 could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on the Corporation's financial condition.

Indigenous Claims

Indigenous peoples have claimed Indigenous rights and title 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 in the construction of infrastructure systems and facilities which could have a material adverse effect on the Corporation's business and financial results

Breach of Confidentiality

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

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable federal, provincial and state 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.

During the year ended December 31, 2019, Freehold received a proposal letter from the CRA wherein the CRA stated that it intends to re-assess and deny Freehold's deduction of certain non-capital losses claimed and carried forward in the tax return filed for the year ended December 31, 2015. Freehold is currently defending its tax filing position and expects it will be successful defending its position; however, if Freehold is not successful in defending its position Freehold may have additional tax liability owing to the CRA and it could impact Freehold's timing for when it may have current taxes payable. For additional information, see "*Legal Proceedings and Regulatory Actions*".

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities, provincial and state transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road 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 (or royalty 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 muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict access to properties in which the Corporation has an interest and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation.

Information Technology Systems and Cyber-Security

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, 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 Manager's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Manager's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

The Corporation maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. The Corporation also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Corporation's efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage its information technology infrastructure. The Corporation applies technical and process controls in line with industry-accepted standards to protect its information, assets and systems, including a written incident response plan for responding to a cyber-security incident. 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, and any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. 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.

Social Media

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Corporation's systems and obtain confidential information. As social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Corporation may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Conflicts of Interest

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

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. Losing the services of such key personnel could 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. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. 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.

All of the Corporation's key personnel are employees of the Manager. If the Management Agreement is terminated, the Manager would cease to manage the operations of the Corporation and the Corporation would be required to ensure that it has sufficient staff to continue to carry on its business. There is no certainty that the Corporation would be able to hire or retain the necessary and appropriate staff to continue to manage the operations of the Corporation upon any termination of the Management Agreement. Any failure of the Corporation to recruit and retain the necessary and appropriate staff upon any termination of the Management Agreement, may negatively impact the Corporation.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on acquiring and managing oil and natural gas royalties in both Canada and the United States and developing and producing its working interest oil and gas assets in Canada. In the future, the Corporation may acquire or move into new industry related activities or new geographical areas, including potentially new areas in the United States, beyond North Dakota, and may acquire different energy related assets; as a result, the Corporation may face unexpected risks or, alternatively, its exposure to one or more existing risk factors may be significantly increased, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Advisories – Cautionary Statement Regarding Forward-Looking Information and Statements*" of this Annual Information Form.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of Freehold consists of an unlimited number of Common Shares and 10,000,000 Preferred Shares. As of the date hereof, there are 118,622,667 Common Shares and no Preferred Shares issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions which are attached to the Common Shares and Preferred Shares.

Common Shares

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Freehold. Subject to the prior satisfaction of all preferential rights attached to other classes of shares of Freehold, the holders of Common Shares are entitled to receive dividends if, as and when declared by the Board of Directors and to receive pro rata the remaining property and assets of Freehold upon its dissolution or winding-up.

Preferred Shares

The Preferred Shares are issuable in one or more series and the Board of Directors may fix their issue, the number of shares of each series and the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares. The Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets or the return of capital in the event of the liquidation, dissolution or winding-up of Freehold, rank on a parity with the Preferred Shares of every other series and are entitled to a preference over the Common Shares and any other shares of Freehold ranking junior to the Preferred Shares.

Other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Shares, the voting rights attached to the Preferred Shares shall be limited to one vote per Preferred Share at any meeting where the Preferred Shares, if any, and Common Shares vote together as a single class.

MARKET FOR SECURITIES

Common Shares

The Common Shares are listed and trade on the TSX under the symbol "FRU". The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the Common Shares on the TSX for the periods indicated:

TORONTO STOCK EXCHANGE
COMMON SHARES TRADING RANGE

	(Cdn$ per Common Share)			
	High	Low	Close	Volume Traded
2019				
January	9.21	8.07	8.91	9,484,915
February	9.35	8.48	8.93	7,545,444
March	9.28	8.27	8.41	6,909,455
April	9.88	8.47	9.20	7,177,746
May	9.17	8.01	8.09	5,102,794
June	8.70	7.98	8.47	4,214,086
July	8.58	7.66	8.15	5,663,581
August	8.23	6.90	7.25	6,286,097
September	8.29	7.10	7.52	6,521,205
October	7.58	6.34	6.47	7,361,540
November	6.97	6.49	6.67	9,278,021
December	7.51	6.46	7.29	12,847,371
2020				
January	8.18	7.01	7.06	16,660,211
February	7.44	5.76	6.02	9,847,376
March 1-3	6.31	5.92	6.01	1,812,881

PRIOR SALES

Other than Deferred Share Units, Freehold did not issue any securities of a class that is not listed or quoted on market place during the year ended December 31, 2019. We issued the following Deferred Share Units (including notional Deferred Share Units resulting from dividends) redeemable to acquire an equal number of Common Shares (less tax withholding) pursuant to the Deferred Share Unit Plan during the year ended December 31, 2019:

Date	Numbered Deferred Share Units	Deemed Price per Deferred Share Unit
January 1, 2019	58,646	$8.27
January 15, 2019	970[(1)]	$8.67
February 15, 2019	1,318[(1)]	$8.76
March 15, 2019	1,346[(1)]	$8.62
April 15, 2019	1,329[(1)]	$9.51
May 15, 2019	1,338[(1)]	$8.77
June 15, 2019	1,455[(1)]	$8.12
July 15, 2019	1,419[(1)]	$8.38
August 15, 2019	1,585[(1)]	$7.55
September 15, 2019	1,553[(1)]	$7.76
October 15, 2019	1,735[(1)]	$6.99
November 15, 2019	1,787[(1)]	$6.84
December 15, 2019	1,737[(1)]	$7.03

(1) Issued as notional Deferred Share Units resulting from the payment of dividends of the Common Shares.

ESCROWED SECURITIES

To our knowledge, none of our securities are held in escrow.

DIVIDENDS

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2019, our legal stated capital was $500 million.

Monthly dividends of Freehold are currently declared for Shareholders of record as of the last day of each month and are paid on or about the 15th day of the following month. The dividends are "eligible dividends" for income tax purposes and thus qualify for the enhanced gross-up and tax credit regime available to certain holders of Common Shares. The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, income taxes and the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board of Directors reviews the dividend policy quarterly and at its discretion, any excess income available for dividends may be directed toward repayment of long-term debt and improvements in working capital.

Record of Cash Dividends

Since January 1, 2020, Freehold has declared a cash dividend of $0.0525 per Common Share for Shareholders of record on January 31, 2020, which was paid on February 18, 2020, has declared a cash dividend of $0.0525 per Common Share for Shareholders of record on February 29, 2020, which is payable on March 16, 2020, and has declared a cash dividend of $0.0525 per Common Share for Shareholders of record on March 31, 2020, which is payable on April 15, 2020.

The tables below set forth the amount of cash dividends paid on the Common Shares during the three most recently completed financial years:

Record Date	Payment Date	Cdn$ per Share
2017		
January 31, 2017	February 15, 2017	0.04
February 28, 2017	March 15, 2017	0.04
March 31, 2017	April 17, 2017	0.05
April 30, 2017	May 15, 2017	0.05
May 31, 2017	June 15, 2017	0.05
June 30, 2017	July 17, 2017	0.05
July 31, 2017	August 15, 2017	0.05
August 31, 2017	September 15, 2017	0.05
September 30, 2017	October 16, 2017	0.05
October 31, 2017	November 15, 2017	0.05
November 30, 2017	December 15, 2017	0.05
December 31, 2017	January 15, 2018	0.05
		0.58

Record Date	Payment Date	Cdn$ per Share
2018		
January 31, 2018	February 15, 2018	0.0500
February 28, 2018	March 15, 2018	0.0500
March 31, 2018	April 16, 2018	0.0525
April 30, 2018	May 15, 2018	0.0525
May 31, 2018	June 15, 2018	0.0525
June 30, 2018	July 16, 2018	0.0525
July 31, 2018	August 15, 2018	0.0525
August 31, 2018	September 17, 2018	0.0525
September 30, 2018	October 15, 2018	0.0525
October 31, 2018	November 15, 2018	0.0525
November 30, 2018	December 17, 2018	0.0525
December 31, 2018	January 15, 2019	0.0525
		0.6250

Record Date	Payment Date	Cdn$ per Share
2019		
January 31, 2019	February 15, 2019	0.0525
February 28, 2019	March 15, 2019	0.0525
March 31, 2019	April 15, 2019	0.0525
April 30, 2019	May 15, 2019	0.0525
May 31, 2019	June 15, 2019	0.0525
June 30, 2019	July 15, 2019	0.0525
July 31, 2019	August 15, 2019	0.0525
August 30, 2019	September 16, 2019	0.0525
September 30, 2019	October 15, 2019	0.0525
October 31, 2019	November 15, 2019	0.0525
November 30, 2019	December 16, 2019	0.0525
December 31, 2019	January 15, 2020	0.0525
		0.6300

Passive Foreign Investment Company

In consultation with its U.S. tax advisors, Freehold believes it should be classified as a passive foreign investment company ("**PFIC**") under United States federal income tax principles. As such, dividends to taxable individual Shareholders who are United States taxpayers should continue to be subject to the regimes of United States federal income taxation applicable to PFICs. Shareholders who are United States taxpayers should discuss with their tax advisors the reporting requirements with respect to owning shares in a PFIC. Freehold, in order to allow Shareholders the ability to make a Qualified Electing Fund election, posts annually a PFIC Annual Information Statement on its website. Shareholders should contact their own tax advisors for information on correctly completing Form 8621. This information is not available from Freehold.

Direct Deposit Plan

A direct deposit plan has been established for Freehold to provide holders who have Canadian bank accounts with a method of receiving cash dividends as a direct deposit into their bank account.

U.S. Currency Payment Plan

The U.S. currency payment plan allows our holders of Common Shares who maintain U.S. currency accounts to obtain payments in U.S. currency.

DIRECTORS AND OFFICERS

General

Subject to the ultimate authority of the Board of Directors, Freehold, FHT and the Partnership are managed by the Manager.

Governance Agreement

The Governance Agreement provides that if the Manager and its affiliates, including the CN Pension Trust Funds, hold 10% or more of the issued and outstanding Common Shares, the Manager will have the right to nominate for election two individuals as directors of Freehold. If the Manager and its affiliates hold less than 10% of the issued and outstanding Common Shares, the Manager will have the right to nominate for election one individual as a director of Freehold. If the individuals nominated by the Manager fail to get elected or if the Manager ceases to hold any Common Shares (in which case the Manager will not have the right to nominate any individuals as directors of Freehold) but continues to act as manager of Freehold pursuant to the Management Agreement, the Governance Agreement will provide the Manager with the right to have an observer present at all meetings of directors of Freehold. The CN Pension Trust Funds holds, directly or indirectly, approximately 21.9% of the outstanding Common Shares and as a result, has the right to nominate two individuals as directors of Freehold.

Decision Making

Although the Manager provides certain advisory and management services to Freehold pursuant to the Management Agreement, the Board of Directors supervises the management of the business and affairs of Freehold. In particular, all decisions relating to: (a) issuances of additional securities of Freehold; (b) the acquisition and disposition of properties of Freehold, and its subsidiaries and partnerships for a purchase price or proceeds in excess of $10 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities and hedging; and (e) the payment of dividends to Shareholders of Freehold, are made by the Board of Directors. Any amendment to the Management Agreement requires the approval of the Board of Directors. The Board of Directors hold regularly scheduled meetings to review the business and affairs of Freehold and make any necessary decisions relating thereto.

Board of Directors of Freehold

As at March 4, 2020, the Board of Directors was comprised of eight individuals. The name, province of residence, position held and principal occupation of each director of Freehold are as follows:

Name and Province of Residence	Position with Freehold	Principal Occupation	Director Since
Gary R. Bugeaud(1)(2) Alberta, Canada	Director	Corporate Director	May 14, 2015
Peter T. Harrison(4) Quebec, Canada	Director	Manager, Oil and Gas Investments CN Investment Division	July 29, 1996(5)
J. Douglas Kay(2)(3) Alberta, Canada	Director	Corporate Director	May 11, 2016
Arthur N. Korpach(1)(2) Alberta, Canada	Director	Corporate Director	May 9, 2012
Susan M. MacKenzie(2)(3) Alberta, Canada	Director	Corporate Director	May 14, 2014
Thomas J. Mullane(4) Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer Rife (private oil and gas exploration and production company)	May 15, 2013

Name and Province of Residence	Position with Freehold	Principal Occupation	Director Since
Marvin F. Romanow Alberta, Canada	Chair of the Board	Corporate Director	May 14, 2015
Aidan M. Walsh(1)(3) Alberta, Canada	Director	Chief Executive Officer of Baccalieu Energy Inc. (a private oil and gas exploration and production company)	May 15, 2013

(1) Member of Audit Committee.
(2) Member of Governance, Nominating and Compensation Committee.
(3) Member of Reserves Committee.
(4) Directors nominated for election at the last annual meeting of Shareholders held on May 7, 2019 by the Manager pursuant to the Governance Agreement.
(5) Reflects the date of election or appointment as a member of the board of directors of Freehold Resources Ltd. prior to completion of the plan of arrangement on January 1, 2011 that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust.

Officers of Freehold

The following table sets forth the name, province of residence, position held and principal occupation of each of the officers of Freehold:

Name and Province of Residence	Position with Freehold	Principal Occupation	Officer Since
Thomas J. Mullane Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer of Rife	July 18, 2012
David W. Hendry Alberta, Canada	Vice-President, Finance and Chief Financial Officer	Vice-President, Finance and Chief Financial Officer of Rife	December 1, 2019
David M. Spyker Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Rife	November 28, 2016
Lisa N. Farstad Alberta, Canada	Vice-President, Corporate Services	Vice-President, Corporate Services of Rife	March 1, 2020
Robert A. King Alberta, Canada	Vice-President, Business Development	Vice-President, Business Development of Rife	January 6, 2020
Robert E. Lamond Alberta, Canada	Vice-President, Asset Development	Vice-President, Asset Development of Rife	September 5, 2017
Michael J. Stone Alberta, Canada	Vice-President, Land	Vice-President, Land of Rife	March 1, 2010(1)
Karen C. Taylor Alberta, Canada	Corporate Secretary	Corporate Secretary of Rife	February 27, 2008(1)

(1) Reflects the date of appointment as an officer of Freehold Resources Ltd. prior to completion of the plan of arrangement on January 1, 2011 that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust.

Except as described in the detailed biographies of each of the directors and officers set forth below, each of the directors and officers of Freehold has been engaged in his or her principal occupation or in other capacities with the same firm or organization for the past five years.

As at March 4, 2020, the directors and senior officers of Freehold, as a group, beneficially owned or controlled, directly or indirectly, 271,395 Common Shares or less than 1% of the issued and outstanding Common Shares. CN Pension Trust Funds, owned, directly or indirectly, 26,013,264 Common Shares (approximately 21.9%) as at March 4, 2020. From 1996 to March 4, 2020, the Manager has received 3,535,450 Common Shares in payment of the Management Fee.

The following is a brief description of the backgrounds of the directors and officers of Freehold.

Gary R. Bugeaud

Mr. Bugeaud is a Corporate Director and was the Managing Partner of Burnet, Duckworth & Palmer LLP until his retirement in December 2013. He has over 23 years of legal experience focused on securities, corporate finance, mergers and acquisitions, and corporate governance matters. Mr. Bugeaud has a Bachelor of Commerce (Finance) degree and a Bachelor of Laws degree from the University of Saskatchewan. Mr. Bugeaud holds the ICD.D designation from the Institute of Corporate Directors.

Peter T. Harrison

Mr. Harrison is Manager, Oil and Gas Investments of the CN Investment Division (Montreal), which manages one of the largest corporate pension funds in Canada. Mr. Harrison has spent over 35 years analyzing business models and investing in public companies. Having managed multi-billion dollar equity portfolios and voted proxies for many years, he brings a deep understanding of investor concerns to the Board. He has been a director of several public and private companies. He has a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario, and is a Chartered Financial Analyst.

J. Douglas Kay

Mr. Kay is a Corporate Director and an experienced oil and gas industry executive with strong land, finance, negotiating and leadership skills. He has over 40 years of diverse responsibilities with Canadian based oil and gas exploration and production companies. Mr. Kay holds a Bachelor of Economics degree from the University of Calgary, is a graduate of the Management Development Program of the University of Western Ontario, and holds the designation of P. Land through the Canadian Association of Petroleum Landmen (CAPL). Mr. Kay holds the ICD.D designation from the Institute of Corporate Directors. He currently serves on the boards of Westbrick Energy Ltd. as Chairman and is a director and former Chair of the Explorers and Producers Association of Canada (EPAC).

Arthur N. Korpach

Mr. Korpach is a Corporate Director. He has four years of public company audit and 27 years of investment banking experience, with a focus on the energy sector. His experience includes providing advice on strategy, business plans, capital structure, credit strategy, financing, and mergers and acquisitions. He has advised clients on over 300 transactions. Mr. Korpach is a Fellow Chartered Accountant and a Chartered Business

Valuator. Mr. Korpach is a past chair of the Accounting Standards Board of the Institute of Chartered Professional Accountants. He has a Bachelor of Commerce degree from the University of Saskatchewan and an MBA from Harvard Business School. Mr. Korpach holds the ICD.D designation from the Institute of Corporate Directors. Mr. Korpach is a director of Inter Pipeline Ltd.

Susan M. MacKenzie

Ms. MacKenzie is a Corporate Director, independent consultant and former oil and gas industry executive with over 25 years of energy sector experience in operations and service support areas. She has a proven track record in the areas of governance, strategy development, organizational alignment, operational execution and project management, and she has demonstrated success in corporation-wide policy development and implementation. Ms. MacKenzie holds a Bachelor of Engineering (Mechanical) degree from McGill University and an MBA from the University of Calgary. She is a Life member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Ms. MacKenzie holds the ICD.D designation from the Institute of Corporate Directors. She is a director of Enerplus Corporation, Precision Drilling Corporation and TransGlobe Energy Corporation.

Thomas J. Mullane

Mr. Mullane is our President and Chief Executive Officer. He joined Rife in July 2012 and was appointed President and Chief Executive Officer in May 2013. He has over 25 years of industry experience and a broad background in exploitation and production engineering gathered from both domestic and international assignments. His roles have included responsibility and oversight of acquisitions, divestitures, exploitation and reservoir engineering management, with significant experience in horizontal drilling. He graduated from the University of Alberta with a Bachelor of Science degree in Chemical Engineering and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Mr. Mullane holds the ICD.D designation from the Institute of Corporate Directors.

Marvin F. Romanow

Mr. Romanow is a Corporate Director, Executive in Residence at the University of Saskatchewan, and former oil and gas industry executive with over 30 years of experience. He has a proven track record in the areas of operating, financial and strategic leadership. His executive roles provided direct engagement with shareholders and directors at two major public corporations over the past 20 years. Mr. Romanow is a graduate of Harvard's Program for Management Development and in October 2007 he completed INSEAD's Advance Management Programme. He has an MBA and a Bachelor of Engineering, with Great Distinction, from the University of Saskatchewan. Mr. Romanow holds the ICD.D designation from the Institute of Corporate Directors. He currently serves on the boards of SaskPower and the Arnie Charbonneau Cancer Institute.

Aidan M. Walsh

Mr. Walsh is Chief Executive Officer of Baccalieu Energy Inc. (Calgary), a private junior oil and gas company that he co-founded in 2008. Mr. Walsh has over 42 years of oil and gas experience in production, marketing, transportation, acquisitions, finance, facility engineering, and construction. He is a proven negotiator and a strategic thinker with strong leadership and analytical skills. He has experience interacting with industry partners as well as regulators and federal and provincial government representatives on issues affecting the Canadian oil and gas industry. Mr. Walsh has a Bachelor of Engineering degree in Mechanical Engineering from Memorial University of Newfoundland and a Masters of Business Administration degree from the University of Calgary. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Mr. Walsh holds the ICD.D designation from the Institute of Corporate Directors. He is currently a director at Baccalieu Energy Inc. and Bonterra Energy Corp., and is a former director and Chair of the Explorers and Producers Association of Canada (EPAC).

David W. Hendry

Mr. Hendry is our Vice-President, Finance and Chief Financial Officer. He joined Rife in December 2019. Prior to joining Rife, Mr. Hendry served as Chief Financial Officer of Obsidian from January 2017 to November 2019 and served as Vice-President, Finance of Obsidian from May 2015 to December 2016. Mr. Hendry served as Vice-President, Finance of Talisman Energy Inc. from August 2009 to April 2015. Mr. Hendry is a Chartered Professional Accountant with over 25 years of finance experience. Mr. Hendry has a Bachelor of Commerce degree from the University of Calgary.

David M. Spyker

Mr. Spyker is our Chief Operating Officer. He joined Rife in November 2016. Prior to joining Rife, he held various roles at Anderson Exploration Ltd. and Anderson. Most recently he held the role of Chief Operating Officer at Anderson Energy Inc. Mr. Spyker holds a Bachelor of Sciences degree in Mechanical Engineering from the University of Alberta and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Lisa N. Farstad

Ms. Farstad was appointed Vice President, Corporate Services in March 2020. She joined Rife in September of 2015 as Manager, Human Resources and Information Services. Prior to joining Rife, Ms. Farstad spent 14 years with Bonavista Energy Corporation in various human resources roles including Manager, Human Resources. Ms. Farstad has a Bachelor of Arts degree from the University of Calgary and a Human Resources Management Certificate from the University of Calgary.

Robert A. King

Mr. King is our Vice-President, Business Development. He joined Rife in January 2020, and was, prior thereto, Managing Director at RBC Capital Markets. Mr. King has over 20 years' experience in investment banking where he has spent the entirety of his career progressing through roles of increasing accountability and responsibility. He possesses significant merger, acquisition and divestiture and capital markets experience with a focus on upstream oil and gas. Mr. King has a Bachelor of Commerce degree from the University of Calgary.

Robert E. Lamond

Mr. Lamond is our Vice-President, Asset Development. He joined Rife in September 2017. He previously held various geoscience and managerial roles at Murphy Oil Corporation, Shell Canada Ltd., and Imperial

Oil Ltd. Most recently he held the role of General Manager, Geoscience at Murphy Oil. Mr. Lamond holds a Bachelor of Science degree in Geology from Queen's University and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Michael J. Stone

Mr. Stone is our Vice-President, Land and has held such position since March 2010. Mr. Stone has a Bachelor of Commerce degree from the University of Calgary and is a member of the Canadian Association of Petroleum Landmen (CAPL).

Karen C. Taylor

Ms. Taylor is our Corporate Secretary. Ms. Taylor joined Rife in February 1997 was appointed Corporate Secretary in February 2008. Ms. Taylor is a member of the Governance Professionals of Canada (GPC).

Corporate Cease Trade Orders or Bankruptcies

Except as described below, during the past ten years, none of the current directors and executive officers of Freehold is or has been a director, chief executive officer or chief financial officer of any company that: (i) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, while that person was acting in the capacity as director, chief executive officer or chief financial officer; (ii) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, 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. None of the directors or executive officers of Freehold is as at the date of the annual information form, or has been within 10 years before the date of the annual information form, a director or executive officer of any company 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.

Mr. Harrison was a director of Spyglass Resources Ltd. ("**Spyglass**") and resigned on November 26, 2015. Spyglass was placed into receivership on November 26, 2015. The common shares of Spyglass were suspended from trading on the TSX on December 31, 2015. The Alberta Securities Commission and certain other securities regulatory authorities in Canada issued cease trade orders against Spyglass in May 2016.

Personal Bankruptcies

None of the directors or executive officers of Freehold has nor any Shareholder holding sufficient number of securities of Freehold to affect materially the control of Freehold, within the past 10 years, 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 proposed director.

Penalties or Sanctions

No director, executive officer or promoter of Freehold nor any Shareholder holding sufficient number of securities of Freehold to affect materially the control of Freehold, has been subject to any penalties or sanctions imposed by a court, securities regulatory authority or other regular authority or has entered into a settlement agreement with a securities regulatory authority.

AUDIT COMMITTEE

The full text of the audit committee mandate is included in Appendix C of this AIF.

Composition of Audit Committee

Freehold's audit committee consists of Mr. Arthur Korpach (Chair), Mr. Gary Bugeaud and Mr. Aidan Walsh. All members of the audit committee are independent and financially literate as those terms are used under National Instrument 52-110 Audit Committees. See "*Governance – Board of Directors of Freehold*".

Pre-Approval Policies and Procedures

The audit committee pre-approves all non-audit services to be provided to Freehold by the external auditors. Prior to the commencement of Freehold's fiscal year, the audit committee pre-approves expenditures with a dollar limit for services related to consultations as to the accounting or disclosure treatment of transactions, and for expenditures with a dollar limit for services related to taxation matters. The audit committee must pre-approve any costs that exceed these limits.

External Auditor Service Fees

The following table sets out the fees for KPMG LLP, our external auditor, in the two most recently completed financial years.

	Year Ended December 31	
	2019	2018
Audit fees[1]	188,000	183,000
Audit-related fees[2]	16,800	25,000
Tax fees[3]	12,500	22,500
All other fees	-	-
Total	217,300	230,500

(1) Audit fees consist of fees for the audit of Freehold's annual financial statements, reviews of interim consolidated financial statements for the first, second, and third quarters of the respective year, or services that are normally provided in connection with statutory and regulatory filings or engagements. Fees do not include administrative or Canadian Public Accountability Board surcharges.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of Freehold's financial statements and are not reported as Audit Fees. The services provided in this category includes work performed by Freehold's external auditors in connection with audit work performed on International Financial Reporting Standards (IFRS) 9, IFRS 15 and IFRS 16.

(3) Tax fees consist of fees for tax compliance and advisory services. During 2018 and 2019, $12,500 was for U.S. tax compliance and the remainder was for advisory services.

THE MANAGER

Business of the Manager

The Manager provides comprehensive oil and gas company management and operational services to Freehold, FHT, and the Partnership. The Manager is a wholly-owned subsidiary of Rife. Pursuant to an agreement between Rife and the Manager dated November 25, 1996, Rife provides the Manager, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to Freehold, FHT and the Partnership.

Employees

Freehold has no employees but rather is managed by the Manager pursuant to the Management Agreement. On December 31, 2019, Rife had 84 full and part-time employees in the Calgary office and 9 full-time employees in their field operations, the majority of whom are on contract to the Manager. These personnel also render services to Rife and Canpar.

Management Agreement

Pursuant to the Management Agreement, Freehold, FHT and the Partnership engaged the Manager to:

- administer all matters relating to the securities of Freehold, including the Common Shares, and the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold, FHT and the Partnership, including: (i) determining the total amount owing to Freehold and its subsidiaries and partnerships from third parties and conducting joint venture audits as required; (ii) determining the total amounts owing to Shareholders and arranging for dividends to Shareholders, subject to the supervision of Freehold; (iii) providing Shareholders with periodic reports on the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold and its subsidiaries and partnerships; and (iv) providing Shareholders with financial reports and tax information relating to the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold and its subsidiaries and partnerships;

- provide management services for the economic and efficient exploitation of oil and natural gas properties;

- operate oil and natural gas properties that Freehold and its subsidiaries and partnerships are entitled to operate and monitor the activities of third party operators;

- recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for Freehold and its subsidiaries and partnerships;

- negotiate on behalf of Freehold and its subsidiaries and partnerships all exploitation and development agreements, operating agreements, working agreements, farmin and farmout agreements, leases and other documents relating to the exploitation of the oil and natural gas properties as may be advisable;

- recommend and negotiate banking arrangements for Freehold; and
- provide office space, office furnishings and equipment and personnel necessary for the proper administration of the assets of Freehold and its subsidiaries and partnerships.

In exercising its power and discharging its duties under the Management Agreement, the Manager will be required to exercise that degree of care, diligence and skill that a reasonably prudent advisor and manager in respect of oil and gas properties in western Canada would exercise in comparable circumstances.

The Management Agreement will continue in force until terminated by either the Manager or Freehold in accordance with the terms of the Management Agreement. The Manager can terminate the Management Agreement at any time after November 26, 2016 by providing six months written notice prior to the date of such termination. Freehold can terminate the Management Agreement at any time after May 26, 2020 by providing six months written notice prior to the date of such termination. Alternatively, Freehold can terminate the Management Agreement at any time after November 26, 2016 if the Manager and its affiliates cease to beneficially own or exercise control or direction over (in aggregate) 5% or more of the issued and outstanding Common Shares for a period of more than 90 consecutive days by providing six months written notice prior to termination. In addition, if a "Change of Control" (as defined in the Management Agreement) of Freehold occurs after November 26, 2016, Freehold will have the right to terminate the Management Agreement by providing written notice to the Manager within 90 days of such Change of Control together with making a payment to the Manager of $2,000,000.

We may also terminate the Management Agreement at any time without the payment of compensation to the Manager if the Manager institutes bankruptcy proceedings, seeks relief under bankruptcy law, consents to the appointment of a receiver, voluntarily suspends transaction of its usual business, is declared bankrupt or insolvent, if a receiver is appointed in respect of the Manager, or if the Manager fails to carry out its material obligations under the Management Agreement and does not commence to cure such failure within 30 days of notice being given.

Proceeds relating to subscription offerings, Royalty Income and other revenues generated from or associated with any interest of Freehold may not be commingled with the funds of any other entity that is managed by the Manager.

The Manager will be paid the Management Fee for providing all of the management services. The Manager will be indemnified by Freehold in respect of certain damages that it may suffer in discharging its obligations under the Management Agreement provided that such damages do not arise from the fraud, wilful default, gross negligence or bad faith of the Manager.

The Board of Directors will review on an ongoing basis both the nature and extent of the services required of the Manager and the costs of providing the same. All amendments to the Management Agreement must be approved by a majority of the members of the Board of Directors.

Compensation

The Manager will be compensated as follows for providing services to Freehold, FHT and the Partnership.

Management Fee

Under the terms of the Management Agreement, the Manager is issued Common Shares quarterly as payment of the Management Fee. In 2017, 2018 and 2019 an aggregate of 220,000, 220,000 and 220,000 Common Shares, respectively, were issued to the Manager as payment of the Management Fee. As at December 31, 2019, the quarterly Management Fee was 55,000 Common Shares.

Under the terms of the Management Agreement, the Common Shares issuable as payment of the Management Fee will be gradually reduced over the next several years, as follows:

- in 2020 the Common Shares issuable on payment of the Management Fee will be capped at 41,250 Common Shares paid quarterly;
- in 2021 the Common Shares issuable on payment of the Management Fee will be capped at 27,500 Common Shares paid quarterly;
- in 2022 the Common Shares issuable on payment of the Management Fee will be capped at 13,750 Common Shares paid quarterly; and
- in 2023 and beyond the Common Shares issuable on payment of the Management Fee will be capped at 5,500 Common Shares paid quarterly.

In addition, the Management Agreement provides a mechanism for reducing the number of Common Shares issuable as payment of the Management Fee if the market price of the Common Shares at such time exceeds $19.00 per Common Share. Pursuant to the Management Agreement, the Management Fee, at the option of Freehold, may be paid by (i) the issuance of Common Shares, or (ii) cash equal to the value of such Common Shares as determined by the market price of such Common Shares at such time.

General and Administrative Costs

The Manager is reimbursed for general and administrative costs incurred by Rife on behalf of Freehold, FHT and the Partnership (in 2019 – 48%). General and administrative costs are generally charged to Freehold, FHT and the Partnership by the Manager based on time spent and direct costs incurred in fulfilling the obligations of the Manager to Freehold, FHT and the Partnership pursuant to the Management Agreement. Commencing in 2017, the allocation of costs based on time spent is adjusted quarterly based on the actual percentage for the allocation of time spent by Rife's staff in the prior quarter (previously, the adjustment was only made once annually).

Effective July 1, 2019, Rife entered into a new office lease. Concurrently with Rife entering into the new office lease, Freehold and Rife entered into an office lease sharing agreement pursuant to which Freehold is responsible for its proportional share of the new office lease based on the allocation of general and administrative costs between Freehold and Manager in accordance with the Management Agreement provided that the minimum percentage of the office lease that Freehold will be responsible for is 40% and the maximum percentage of the office lease that Freehold will be responsible is 60%.

Long-Term Incentive Plan

Since 2017, Freehold's proportionate share of long-term incentive compensation consisted of grants of performance awards and restricted awards under Freehold's incentive award plan. In 2019, a total of 102,616 (2018 – 65,403) restricted awards and 106,919 (2018 – 63,205) performance awards were granted to employees of Rife under the Freehold incentive award plan reflecting Freehold's 48% (2018 – 48%) of long-term incentive compensation granted to Rife employees in 2019. Restricted awards and performance awards accumulate the full value of Freehold's monthly dividend and upon vesting, the payout amount is adjusted to reflect these dividends and, in the case of performance awards, a performance multiplier based on certain applicable Freehold performance factors.

Manager's Annual Bonus Plan

We pay our proportionate share (2019 – 48%) of annual cash bonuses paid under the Rife short-term incentive plan for employees of the Manager.

Directors' Deferred Share Unit Plan

The Deferred Share Unit Plan consists of fully vested Deferred Share Units, granted annually to our non-management directors. Dividends to Shareholders we declare prior to redemption are assumed to be reinvested in notional share units on the date of dividend.

Directors and Officers of the Manager

The name, province of residence, position held and principal occupation of each director and officer of the Manager are set out below:

Name and Province of Residence	Position with the Manager	Principal Occupation	Director or Officer of the Manager Since
Thomas J. Mullane Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer of Rife	July 18, 2012
David W. Hendry Alberta, Canada	Vice-President, Finance and Chief Financial Officer and Director	Vice-President, Finance and Chief Financial Officer of Rife	December 1, 2019
David M. Spyker Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Rife	November 28, 2016
Lisa N. Farstad Alberta, Canada	Vice-President, Corporate Services	Vice-President, Corporate Services of Rife	March 1, 2020

Robert A. King Alberta, Canada	Vice-President, Business Development	Vice-President, Business Development of Rife	January 6, 2020
Robert E. Lamond Alberta, Canada	Vice-President, Asset Development	Vice-President, Asset Development of Rife	September 5, 2017
Michael J. Stone Alberta, Canada	Vice-President, Land	Vice-President, Land of Rife	March 1, 2010
Alan G. Glessing Alberta, Canada	Controller	Controller of Rife	September 18, 2008
Karen C. Taylor Alberta, Canada	Corporate Secretary	Corporate Secretary of Rife	February 1, 2008

As at March 4, 2020, the directors and senior officers of the Manager as a group beneficially owned, directly or indirectly, or exercised control or direction over 94,109 Common Shares. Rife owns 100% of the outstanding shares in the capital of the Manager. All of the shares of Rife are owned by the CN Pension Trust Funds.

CONFLICTS OF INTEREST

There may be situations in which the interests of the Manager will conflict with those of the Shareholders. As part of the ordinary course of business of the Manager, the Manager may continue to acquire oil and natural gas properties on its own behalf and on behalf of persons other than Freehold. The Manager may manage and administer such properties, as well as enter into other types of energy-related management, advisory and investment activities. Thus, neither the Manager nor its management will carry on their full-time activities on behalf of Freehold and, when acting on its own behalf or on behalf of others, may at times act in contradiction to or in competition with the interests of the Shareholders. In addition, there are times when Freehold may participate or enter into transactions with Canpar and Rife.

In resolving such conflicts, decisions will be made by the Manager on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties all consistent with the duties of the Manager to each such group of persons. The Management Agreement contains provisions that require the Manager to make disclosure to the Board of Directors of the fact and substance of any particular conflict of interest and to use all reasonable efforts to resolve such conflicts of interest in a manner that will treat Freehold and the other interested party fairly taking into account all of the circumstances of Freehold and such interested party and to act honestly and in good faith in resolving such matters.

Although the Manager provides advisory and management services to Freehold, the Board of Directors supervises the management of the business and affairs of Freehold. The Board of Directors makes all decisions relating to: (i) the issuance of additional Common Shares; (ii) the acquisition and disposition of properties for a purchase price or proceeds in excess of $10 million; (iii) the approval of capital expenditure budgets; (iv) the establishment of credit facilities; and (v) the determination of the amount of dividends to Shareholders.

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

The Board of Directors has implemented a related party transaction policy that sets out a specific process for consideration and Board approval of potential acquisitions, dispositions, joint ventures, farm-in arrangements and transactions of a similar nature that are outside the ordinary course of business ("**Related Party Transactions**") and involve Freehold and Rife and/or Canpar. The policy provides for negotiation of the terms of any Related Party Transaction by representatives of Freehold who do not have a material interest in such transaction. In addition, the policy requires that any such Related Party Transaction must be approved by members of the Board of Directors who do not have a material interest in such transaction.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Other than as described below, to the knowledge of management of Freehold as at the date hereof, there are no legal proceedings that Freehold is a party to, or that any of Freehold's property is the subject of, that is material to Freehold, and there are no such material legal proceedings known to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" to Freehold if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of Freehold's consolidated current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, we have included the amount involved in the other proceedings in computing the percentage.

There were no: (i) penalties or sanctions imposed against Freehold by a court relating to securities legislation or by a security regulatory authority during its most recently completed financial year or during the current financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against Freehold that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements Freehold entered into before a court relating to securities legislation or with a securities regulatory authority during Freehold's most recently completed financial year or during the current financial year.

During the year ended December 31, 2019, Freehold received a proposal letter from the CRA wherein the CRA stated that it intends to re-assess and deny Freehold’s deduction of certain non-capital losses claimed and carried forward in the tax return filed for the year ended December 31, 2015.

Freehold will vigorously defend its tax filing position, however, it anticipates that proceedings with the CRA could take considerable time to resolve. If the CRA issues the notice of reassessment described in the CRA proposal letter, Freehold may also be reassessed with respect to the deduction of its non-capital losses in all of its tax filings subsequent to December 31, 2015. In such event, Freehold may utilize alternate claims available that would partially offset any tax liability for tax returns filed in periods subsequent to December 31, 2015. Freehold's assessed tax liability for the taxation years 2015 to 2018 would be approximately $18 million (plus interest). In this event, Freehold will be required to pay a deposit of 50% of the assessed tax liability, and it will have 90 days from the date of the notice of reassessment to prepare and file a notice of objection. Freehold firmly believes it will be successful defending its position and therefore any amounts paid to CRA should be refunded plus interest. No provisions have been made in the consolidated financial statements relating to the CRA proposal letter.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed below or herein, there were no material interests, direct or indirect, of any directors or executive officers of the Manager, directors or executive officers of Freehold, any Shareholder who beneficially owns more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect Freehold.

The Manager and Rife are wholly-owned subsidiaries of the CN Pension Trust Funds, which held 26,013,264 Common Shares as at March 4, 2020, representing approximately 21.9% of the outstanding Common Shares. The Manager receives certain compensation and reimbursement for a portion of general and administrative expenses for providing management services to Freehold, FHT and the Partnership as described under "The Manager". All transactions during 2019 were in the normal course of operations and were measured at the exchange amount, which is the amount of consideration established and agreed to by Freehold and the Manager.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts we have entered into within the most recently completed financial year, or before the most recently completed financial year but which are still in effect, are the following:

- the Governance Agreement dated December 31, 2010, as described under the heading "*Governance – Governance Agreement*";
- the Management Agreement dated November 9, 2015, as described under the heading "*The Manager – Management Agreement*"; and
- the agreement governing our credit facilities between Freehold, FHT and the Partnership and their lenders dated May 9, 2018 as amended May 7, 2019 and as described under "*Borrowing*".

INTEREST OF EXPERTS

Names of Experts

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

Interest of Experts

KPMG LLP are our auditors and have confirmed they are independent with respect to Freehold within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

As at the date hereof, the designated professionals (as defined in NI 51-102) of Trimble, as a group, beneficially owned, directly or indirectly, less than 1% of our outstanding securities including the securities of our associate or affiliate entities.

In addition, none of the aforementioned persons or companies, nor any partner, 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 the Manager or Freehold or any of our associate or affiliate entities.

ADDITIONAL FINANCIAL AND OTHER INFORMATION

Additional information about Freehold may be found on SEDAR at www.sedar.com. Information about remuneration and indebtedness of directors and officers of Freehold and the Manager, principal holders of the Common Shares and securities authorized for issuance under our security-based compensation arrangements, will be contained in our Management Information Circular to be dated on or about March 16, 2020, which relates to our Annual Meeting of Shareholders to be held on May 5, 2020. Additional financial information is provided in Freehold's consolidated financial statements for the year ended December 31, 2019 and the accompanying management's discussion and analysis.

For copies of our consolidated financial statements and accompanying management's discussion and analysis and the Management Information Circular and additional copies of the AIF (in certain circumstances reasonable fees may apply) please contact:

Corporate Secretary
Freehold Royalties Ltd.
Suite 1000, 517 – 10th Avenue SW
Calgary, Alberta T2P 0A8
Telephone: 403-221-0802
Toll Free: 1-888-257-1873
Fax: 403-221-0888

APPENDICES

Appendix A

Form 51-101F2
Report on Reserves Data by Independent Qualified Reserves Evaluators

To the Board of Directors of Freehold Royalties Ltd. (the "**Corporation**") and Rife Resources Management Ltd., as manager of the Corporation:

1. We have evaluated the Corporation's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation'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%, included in the reserves data of the Corporation evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) ($000s)			
			Audited	Evaluated	Reviewed	Total
Trimble Engineering Associates Ltd.	Reserve and Present Worth Appraisal of Certain Oil and Gas Properties At December 31, 2019 Dated January 30, 2020	Canada & United States	$0	$771,169	$0	$771,169

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

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

Trimble Engineering Associates Ltd., Calgary, Alberta, Canada, March 4th, 2020.

Per: (signed) "*Stephen C. Trimble*"
Stephen C. Trimble, P.Eng.
President & Managing Director

APPENDIX B

Form 51-101F3
Report of Management and Directors on Oil and Gas Disclosure

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

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

The Reserves Committee of the Board of Directors of the Corporation has

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

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

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

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

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

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

c. the content and filing of this report.

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

(signed) "*Thomas J. Mullane*"
Thomas J. Mullane
President, Chief Executive Officer and Director

(signed) "*David M. Spyker*"
David M. Spyker
Chief Operating Officer

(signed) "*Aidan M. Walsh*"
Aidan M. Walsh
Director and Chair, Reserves Committee

(signed) "*Susan M. MacKenzie*"
Susan M. MacKenzie
Director and Member, Reserves Committee

DATED as of this 4th day of March, 2020.

APPENDIX C

Audit Committee Mandate

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Freehold Royalties Ltd. ("**Freehold**") to which the Board has delegated certain responsibilities for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee are as follows:

1. to assist directors in meeting their responsibilities, especially for accountability, in respect of the preparation and disclosure of the financial statements of Freehold and related matters;
2. to provide better communication between directors and the external auditors;
3. to enhance the external auditors' independence;
4. to increase the transparency, credibility and objectivity of financial reporting; and
5. to strengthen the role of the independent directors by facilitating in-depth discussions between directors on the Committee, management and the external auditors.

Membership of Committee

1. The Committee will be comprised of at least three directors, all of whom are independent (as such term is used in National Instrument 52-110 – Audit Committees ("NI 52-110")).
2. The Board will have the power to appoint the Committee Chair.
3. All of the members of the Committee will be financially literate. The Board has adopted the definition for financial literacy used in NI 52-110.

Meetings

1. At all meetings of the Committee, every question will be decided by a majority of the votes cast. In case of an equality of votes, the Committee Chair is not entitled to a second or deciding vote.
2. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board.
3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer ("CFO") will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Committee Chair.
4. The Committee will forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.
5. The Committee will meet in-camera with the external auditors at least quarterly (in connection with the preparation of the annual and quarterly financial statements) and at such other times as the external auditors and the Committee consider appropriate.
6. The Committee will hold an in-camera session, without members of management or management directors, at each meeting. The Committee may invite other directors, members of management, and advisors to attend all or part of any in-camera session, as it deems advisable.

Mandate and Responsibilities

The mandate and responsibilities of the Committee will be as set forth below:

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

2. Satisfy itself on behalf of the Board with respect to Freehold's internal control systems, which include:
   (a) identifying, monitoring and mitigating business risks; and
   (b) ensuring compliance with legal, ethical and regulatory requirements;

3. Review the annual and quarterly financial statements of Freehold prior to their submission to the Board for approval. The process should include but not be limited to:
   (a) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
   (b) reviewing significant accruals, reserves or other estimates such as impairment testing;
   (c) reviewing accounting treatment of unusual or non-recurring transactions;
   (d) ascertaining compliance with covenants under loan agreements;
   (e) reviewing adequacy of reclamation provisions;
   (f) reviewing disclosure requirements for commitments and contingencies;
   (g) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   (h) reviewing unresolved differences between management and the external auditors; and
   (i) obtaining explanations of significant variances with comparative reporting periods;

4. Review the financial statements, prospectuses, management discussion and analysis, annual information forms, earnings news releases, and all public disclosure containing audited or unaudited financial information before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Freehold's disclosure of all other financial information and will periodically assess the accuracy of those procedures;

5. Recommend to the Board the annual appointment of external auditors, and in so doing:
   (a) annually review the performance and independence of the external auditors;
   (b) review the terms of engagement of the auditor, including the compensation of the auditors;
   (c) confirm that the auditors will report directly to the Committee;
   (d) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
   (e) review and approve any non-audit services to be provided by the auditors' firm and consider the impact on the independence of the auditors;

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

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

8. Review, on an annual basis, the risk management policies and procedures of Freehold, including hedging, litigation and insurance;

9. Review and approve management's hiring policies regarding current and former partners and employees of the present and former external auditor;

10. Establish procedures for:
    (a) the receipt, retention and treatment of complaints received by Freehold regarding accounting, internal accounting controls or auditing matters; and
    (b) the confidential, anonymous submission by employees of Rife Resources Management Ltd. (the "**Manager**") of concerns regarding questionable accounting or auditing matters;

11. To review and report to the Board on the procedures in place for reporting and certification under the *Extractive Sector Transparency Measures Act* (Canada) ("**ESTMA**");

12. The Committee will have the authority to investigate any financial activity of Freehold. All employees of the Manager are to cooperate as requested by the Committee; and

13. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling their responsibilities at the expense of Freehold without any further approval of the Board.

Adopted January 1, 2011; amended August 1, 2019

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