2020

Annual Information Form

Dated
March 4
2021

Freehold
ROYALTIES LTD.

TSX **FRU**

Quality Assets. Sustainable Dividends.

Table of Contents

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 expectation that Freehold will have minimal future development costs associated with development of our reserves;
- expected timing 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 expected impact of the U.S. Royalty Transaction on Freehold's reserves and associated future net revenue in future years;
- 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 less than $1.0 million will be directed toward reclamation activities on Freehold's working interest properties in 2021, with the focus on site restoration for previously abandoned wells;
- 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;
- the impact of the continuing COVID-19 pandemic;
- 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;
- our 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, 2020 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.

"**Acquired U.S. Royalty Assets**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**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.

"**COVID-19**" means the disease caused by severe acute respiratory syndrome coronavirus 2, first identified in December 2019.

"**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.

"**Financing**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**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 (operated and non-operated) 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 number 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 (operated and non-operated) 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*.

"**Offering**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**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*".

"**Reassessments**" has the meaning ascribed thereto under "*Other Oil and Gas Information – Tax Horizon*".

"**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.

"**Subscription Receipts**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**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 29, 2021 prepared by Trimble, evaluating our oil, natural gas, natural gas liquids, and sulphur reserves as at December 31, 2020.

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

"**U.S. Royalty Transaction**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**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. 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. See "*The Manager – Compensation - Management Fee*". 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 22.04% 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.

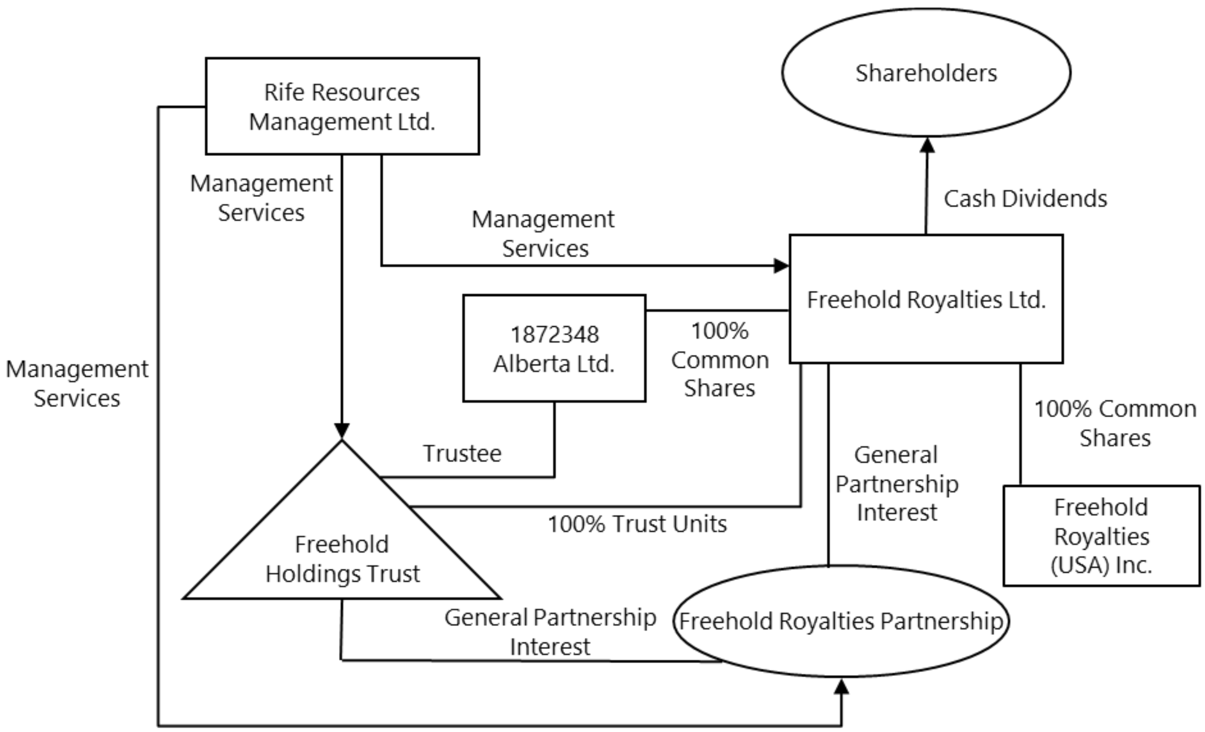
Structure of the Corporation

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 the Business

The following is a summary description of the development of our business since January 1, 2018.

Year Ended December 31, 2018

In February 2018, Freehold disposed of its 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 interest. Average production and operating income associated with the asset in 2017 was 179 boe/d and $2.1 million (before GORR), respectively. The transaction 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.

Year Ended December 31, 2020

On November 24, 2020 Freehold entered into a definitive agreement with a private seller to acquire certain mineral title and royalty interest assets in the United States (the "**Acquired U.S. Royalty Assets**") for an aggregate purchase price of US$58 million (the "**U.S. Royalty Transaction**").

In connection with the U.S. Royalty Transaction, on December 9, 2020, Freehold closed a bought deal offering of 9,856,000 subscription receipts ("**Subscription Receipts**") of the Corporation at a price of $4.80

per Subscription Receipt for gross proceeds of approximately $47 million (the "**Offering**"). Concurrent with the closing of the Offering, the pension trust funds for employees of Canadian National Railway Company purchased 2,791,667 Subscription Receipts at a price of $4.80 per Subscription Receipt for gross proceeds of approximately $13.4 million on a non-brokered private placement basis (together with the Offering, the "**Financing**").

Subsequent Event

U.S. Royalty Transaction

The U.S. Royalty Transaction closed on January 5, 2021 and the net proceeds of the Financing were released from escrow to Freehold to partially fund the purchase price for the Acquired U.S. Royalty Assets, with the remainder of the purchase price funded by drawing on existing credit facilities. In addition, as a result of and on closing of the U.S. Royalty Transaction and in accordance with the terms of the Subscription Receipts, each Subscription Receipt was exchanged for one Common Share.

The U.S. Royalty Transaction added exposure to approximately 400,000 gross drilling unit acres to Freehold's portfolio with minimal exposure to U.S. Federal lands (less than 4% of Acquired U.S. Royalty Assets acreage). As a result of the U.S. Royalty Transaction, Freehold acquired a royalty interest in approximately 1,800 producing wells. The Acquired U.S. Royalty Assets include mineral title and royalty interests in eight states and 12 oil and natural gas basins and are anticipated to add 1,150 boe/d of production in 2021. The majority of the value of the Acquired U.S. Royalty Assets is concentrated in the prolific Permian (Delaware and Midland) and Eagle Ford basins in Texas.

Freehold anticipates that the U.S. Royalty Transaction will have a positive material impact on the volume of reserves and net present values in 2021. However, as the U.S. Royalty Transaction closed after December 31, 2020 such impact has not been incorporated into the Trimble Report and the Statement (as defined below) provided herein. The reserves associated with the Acquired U.S. Royalty Assets will be included in Freehold's reserve report for the year ended December 31, 2021.

Significant Acquisitions

During the year ended December 31, 2020, 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. We have royalty interests in more than 11,000 producing wells and 380 producing units spanning five provinces in Canada and eight states in the United States and receive Royalty Income from approximately 350 operators throughout North America. Freehold's royalty interests include significant mineral title and gross overriding royalty interests that 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 both near and 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 2% of total production in 2020. 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 2020, Freehold participated as a working interest owner in the abandonment of seven wellbores. For 2021, it is expected that less than $1.0 million will be directed toward abandonment and reclamation activities, with the focus on site restoration for previously abandoned wells.

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, 2020, and the preparation date of the Statement is January 29, 2021.

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, 2020 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 as at December 31, 2020 were located 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. As the U.S. Royalty Transaction was completed after December 31, 2020, the Trimble Report did not evaluate or otherwise include the Acquired U.S. Royalty Assets and the amounts set forth in this Statement do not include any amount associated with the Acquired U.S. Royalty Assets. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

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, 2020
FORECAST PRICES AND COSTS(1)(2)(3)

CANADA

	Light and Medium Oil		Tight Oil		Heavy Oil	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)
Proved						
Developed producing	-	3,724	-	715	4	2,093
Developed non-producing	-	-	-	-	-	15
Undeveloped	-	1,328	-	72	-	250
Total proved	-	5,052	-	787	4	2,358
Probable	-	4,567	-	247	2	822
Total proved plus probable	-	9,619	-	1,034	6	3,180

	Conventional Natural Gas		Coal Bed Methane		Shale Gas	
Reserves Category	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
Proved						
Developed producing	244	49,496	-	1,402	-	1,232
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	2,402	-	-	-	964
Total proved	244	51,898	-	1,402	-	2,196
Probable	121	18,023	-	321	-	996
Total proved plus probable	364	69,921	-	1,722	-	3,192

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
Proved				
Developed producing	14	1,660	59	16,880
Developed non-producing	-	-	-	15
Undeveloped	-	72	-	2,283
Total proved	14	1,732	59	19,177
Probable	6	678	29	9,537
Total proved plus probable	20	2,410	87	28,714

UNITED STATES

	Tight Oil		Conventional Natural Gas	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)
Proved				
Developed producing	-	108	-	238
Developed non-producing	-	-	-	-
Undeveloped	-	205	-	409
Total proved	-	314	-	646
Probable	-	178	-	369
Total proved plus probable	-	491	-	1016

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	-	4	-	152
Developed non-producing	-	-	-	-
Undeveloped	-	7	-	280
Total proved	-	10	-	431
Probable	-	5	-	244
Total proved plus probable	-	15	-	676

TOTAL

Reserves Category	Light and Medium Oil Gross (Mbbls)	Light and Medium Oil Net (Mbbls)	Tight Oil Gross (Mbbls)	Tight Oil Net (Mbbls)	Heavy Oil Gross (Mbbls)	Heavy Oil Net (Mbbls)
Proved						
Developed producing	-	3,724	-	823	4	2,093
Developed non-producing	-	-	-	-	-	15
Undeveloped	-	1,328	-	278	-	250
Total proved	-	5,052	-	1,100	4	2,358
Probable	-	4,567	-	425	2	822
Total proved plus probable	-	9,619	-	1,525	6	3,180

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	244	49,733	-	1,402	-	1,232
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	2,811	-	-	-	964
Total proved	244	52,544	-	1,402	-	2,196
Probable	121	18,393	-	321	-	996
Total proved plus probable	364	70,937	-	1,722	-	3,192

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	14	1,663	59	17,031
Developed non-producing	-	-	-	15
Undeveloped	-	78	-	2,563
Total proved	14	1,742	59	19,609
Probable	6	683	29	9,781
Total proved plus probable	20	2,425	87	29,390

(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.
(3) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2020 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	575,776	434,544	352,993	299,776	262,179
Developed non-producing	(15,560)	(10,993)	(8,465)	(6,915)	(5,886)
Undeveloped	114,453	89,538	72,734	60,786	51,943
Total proved	674,669	513,088	417,262	353,647	308,236
Probable	493,142	281,254	181,868	127,130	93,941
Total proved plus probable	1,167,811	794,342	599,131	480,777	402,176

CANADA	After Income Taxes[(4)], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	575,776	434,544	352,993	299,776	262,179
Developed non-producing	(15,560)	(10,993)	(8,465)	(6,915)	(5,886)
Undeveloped	114,453	89,538	72,734	60,786	51,943
Total proved	674,669	513,088	417,262	353,647	308,236
Probable	387,000	218,578	141,464	99,601	74,421
Total proved plus probable	1,061,670	731,666	558,726	453,248	382,657

UNITED STATES	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	7,423	5,984	5,091	4,487	4,050
Developed non-producing	-	-	-	-	-
Undeveloped	15,150	10,735	8,272	6,699	5,602
Total proved	22,573	16,719	13,363	11,186	9,652
Probable	15,642	7,938	5,085	3,686	2,862
Total proved plus probable	38,215	24,657	18,448	14,872	12,514

UNITED STATES	After Income Taxes(4), Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	7,027	5,653	4,801	4,226	3,810
Developed non-producing	-	-	-	-	-
Undeveloped	13,333	9,364	7,170	5,779	4,813
Total proved	20,361	15,017	11,971	10,004	8,623
Probable	11,986	6,032	3,851	2,789	2,165
Total proved plus probable	32,347	21,049	15,823	12,793	10,788

TOTAL	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	583,199	440,527	358,084	304,263	266,229
Developed non-producing	(15,560)	(10,993)	(8,465)	(6,915)	(5,886)
Undeveloped	129,603	100,273	81,006	67,485	57,545
Total proved	697,243	529,807	430,625	364,833	317,888
Probable	508,784	289,192	186,953	130,816	96,803
Total proved plus probable	1,206,027	818,999	617,578	495,648	414,691

TOTAL	After Income Taxes(4), Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	582,803	440,196	357,794	304,002	265,989
Developed non-producing	(15,560)	(10,993)	(8,465)	(6,915)	(5,886)
Undeveloped	127,786	98,901	79,905	66,565	56,756
Total proved	695,030	528,104	429,234	363,651	316,859
Probable	398,987	224,611	145,315	102,390	76,586
Total proved plus probable	1,094,017	752,715	574,549	466,041	393,445

(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 "*Other Oil and Gas Information – Environmental Obligations – Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs*".

(3) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

(4) Based on the inclusion of $753,972,000 of tax pools for Canada and $21,440,000 of tax pools for the United States

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2020
FORECAST PRICES AND COSTS(1)(2)

	Proved Reserves		
($000s)	Canada	United States	Total
Royalty Income	706,674	24,823	731,498
Revenue from working interest properties	1,612	-	1,612
Royalty expense	(241)	(2,250)(4)	(2,491)
Operating costs(3)	(21,858)	-	(21,858)
Development costs	-	-	-
Abandonment and reclamation costs(3)	(11,518)	-	(11,518)
Future net revenue before income taxes	674,669	22,573	697,243
Future income taxes	-	(2,213)	(2,213)
Future net revenue after income taxes	674,669	20,361	695,030

	Proved Plus Probable Reserves		
($000s)	Canada	United States	Total
Royalty Income	1,205,841	42,024	1,247,865
Revenue from working interest properties	2,444	-	2,444
Royalty expense	(328)	(3,808)(4)	(4,136)
Operating costs(3)	(28,616)	-	(28,616)
Development costs	-	-	-
Abandonment and reclamation costs(3)	(11,531)	-	(11,531)
Future net revenue before income taxes	1,167,811	38,215	1,206,027
Future income taxes	(106,142)	(5,868)	(112,010)
Future net revenue after income taxes	1,061,670	32,347	1,094,017

(1) Columns may not add due to rounding

(2) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

(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 "*Other Oil and Gas Information – Environmental Obligations – Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs*".

(4) Represents Severance Tax Deductions

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2020
FORECAST PRICES AND COSTS(1)(2)(3)(4)

CANADA

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	Unit Value
		($000s)	($)
Proved	Light and Medium Oil (including solution gas and by-products)	216,072	42.77/bbl
	Tight Oil (including solution gas and other by-products)	31,818	40.44/bbl
	Heavy Crude Oil (including solution gas and other by-products)	79,773	33.83/bbl
	Conventional Natural Gas (including by-products)	93,343	2.01/Mcf
	Coal Bed Methane (including by-products)	1,876	1.34/Mcf
	Shale Gas (including by-products)	3,378	1.54/Mcf
	Total Proved	417,262	21.76/boe
Proved plus probable	Light and Medium Oil (including solution gas and by-products)	354,473	36.85/bbl
	Tight Oil (including solution gas and other by-products)	38,859	37.59/bbl
	Heavy Crude Oil (including solution gas and other by-products)	98,799	31.07/bbl
	Conventional Natural Gas (including by-products)	109,573	1.84/Mcf
	Coal Bed Methane (including by-products)	2,109	1.22/Mcf
	Shale Gas (including by-products)	4,316	1.35/Mcf
	Total Proved Plus Probable	599,131	20.87/boe

UNITED STATES

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	Unit Value
		($000s)	($)
Proved	Light and Medium Oil (including solution gas and by-products)	-	-
	Tight Oil (including solution gas and other by-products)	13,363	42.61/bbl
	Heavy Crude Oil (including solution gas and other by-products)	-	-
	Conventional Natural Gas (including by-products)	-	-
	Coal Bed Methane (including by-products)	-	-
	Shale Gas (including by-products)	-	-
	Total Proved	13,363	30.97/boe
Proved plus probable	Light and Medium Oil (including solution gas and by-products)	-	-
	Tight Oil (including solution gas and other by-products)	18,448	37.55/bbl
	Heavy Crude Oil (including solution gas and other by-products)	-	-
	Conventional Natural Gas (including by-products)	-	-
	Coal Bed Methane (including by-products)	-	-
	Shale Gas (including by-products)	-	-
	Total Proved Plus Probable	18,448	27.30/boe

TOTAL

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	Unit Value
		($000s)	($)
Proved	Light and Medium Oil (including solution gas and by-products)	216,072	42.77/bbl
	Tight Oil (including solution gas and other by-products)	45,181	41.06/bbl
	Heavy Crude Oil (including solution gas and other by-products)	79,773	33.83/bbl
	Conventional Natural Gas (including by-products)	93,343	2.01/Mcf
	Coal Bed Methane (including by-products)	1,876	1.34/Mcf
	Shale Gas (including by-products)	3,378	1.54/Mcf
	Total Proved	430,625	21.96/boe
Proved plus probable	Light and Medium Oil (including solution gas and by-products)	354,473	36.85/bbl
	Tight Oil (including solution gas and other by-products)	57,306	37.58/bbl
	Heavy Crude Oil (including solution gas and other by-products)	98,799	31.07/bbl
	Conventional Natural Gas (including by-products)	109,573	1.84/Mcf
	Coal Bed Methane (including by-products)	2,109	1.22/Mcf
	Shale Gas (including by-products)	4,316	1.35/Mcf
	Total Proved Plus Probable	617,578	21.01/boe

(1) Columns may not add due to rounding.
(2) The Unit Value is calculated by dividing the discounted Future Net Revenue by the net reserves for the principal product of the Product Type.
(3) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".
(4) For the purposes of calculating future net revenue by product type, operating cost expense, plus abandonment, decommissioning and reclamation capital costs totalling $8,997,000 on a discounted basis in respect of both the proved reserves and proved plus probable reserves categories have been excluded as such costs are related to wells or facilities that have not been attributed reserves and therefore have not been allocated by product type. As such, the columns do not equal the Total Proved and the Total Proved plus Probable future net revenue as a result of such costs being excluded. See "*Other Oil and Gas Information – Environmental Obligations – Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs*".

Definitions and Other Notes

Columns may not add due to rounding.

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.

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, 2020 utilized in the Trimble Report were as follows:

FORECAST PRICES USED IN ESTIMATES
AS OF DECEMBER 31, 2020

	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
2021	47.17	55.76	39.87	45.36	44.63	2.78	2.83	18.18	26.36	59.24	-	0.77
2022	50.17	59.89	43.20	48.96	48.18	2.70	2.87	21.91	32.85	63.19	1.00	0.77
2023	53.17	63.48	46.86	52.91	52.10	2.61	2.90	24.57	39.20	67.34	2.00	0.76
2024	54.97	65.76	48.67	54.95	54.10	2.65	2.96	25.47	40.65	69.77	2.00	0.76
2025	56.07	67.13	49.65	56.05	55.19	2.70	3.02	26.00	41.50	71.18	2.00	0.76
2026	57.19	68.53	50.65	57.16	56.29	2.76	3.08	26.54	42.36	72.61	2.00	0.76
2027	58.34	69.95	51.67	58.30	57.42	2.81	3.14	27.09	43.24	74.07	2.00	0.76
2028	59.50	71.40	52.71	59.47	58.57	2.87	3.20	27.65	44.14	75.56	2.00	0.76
2029	60.69	72.88	53.76	60.66	59.74	2.92	3.26	28.23	45.06	77.08	2.00	0.76
2030	61.91	74.34	54.84	61.87	60.93	2.98	3.33	28.79	45.96	78.62	2.00	0.76
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	0.76

The following table provides the historical weighted average prices realized by Freehold for the year ended December 31, 2020:

FREEHOLD WEIGHTED AVERAGE PRICES
YEAR ENDED DECEMBER 31, 2020

	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	41.39	30.69	1.67	22.78	24.25
United States					
Freehold weighted average price	49.23	-	2.65	12.17	41.79

"**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.

"**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.

"**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.

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

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

The majority of Freehold's reserves as estimated in the Trimble Report are associated with Freehold's royalty interests. Freehold is not responsible for development costs associated with the reserves from its royalty interests. Freehold does not anticipate making any development cost expenditures relating to the reserves associated with its working interest properties and as such no future development costs have been deducted for the purposes of estimating the future net revenue associated with Freehold's reserves in the Trimble Report.

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

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

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 all of Freehold's interests in the United States are 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.

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS(1)

CANADA	**Light and Medium Oil**			**Tight Oil**			**Heavy 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, 2019	147	190	337	-	-	-	94	136	230
Production	(4)	-	(4)	-	-	-	(15)	-	(15)
Technical revisions	-	-	-	-	-	-	5	2	7
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(143)	(190)	(333)	-	-	-	(80)	(136)	(216)
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2020	**-**	**-**	**-**	**-**	**-**	**-**	**4**	**2**	**6**

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, 2019	1,551	1,545	3,096	3	1	4	96	64	160
Production	(293)	-	(293)	(77)	-	(77)	-	-	-
Technical revisions	28	23	51	76	-	76	-	-	-
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(1,040)	(1,454)	(2,495)	(3)	(1)	(4)	(96)	(64)	(160)
Economic factors	(2)	7	4	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2020	**244**	**121**	**364**	**-**	**-**	**-**	**-**	**-**	**-**

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, 2019	71	126	197	587	720	1,307
Production	(7)	-	(7)	(87)	-	(87)
Technical revisions	(8)	2	(6)	14	8	22
Extensions and improved recovery	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(43)	(122)	(165)	(456)	(701)	(1,157)
Economic factors	-	-	1	-	2	2
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2020	**14**	**6**	**20**	**59**	**29**	**87**

(1) Columns may not add due to rounding.

The following reserves 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(1)(2)

CANADA	**Light and Medium Oil**			**Tight Oil**			**Heavy 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, 2019	5,789	4,284	10,073	910	355	1,265	2,719	1,072	3,790
Production	(953)	-	(953)	(136)	-	(136)	(470)	-	(470)
Technical revisions	69	(153)	(85)	5	(112)	(107)	(84)	(228)	(312)
Extensions and improved recovery	276	610	886	8	4	12	265	90	355
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(128)	(175)	(303)	-	-	-	(72)	(112)	(184)
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2020	**5,052**	**4,567**	**9,619**	**787**	**247**	**1,034**	**2,358**	**822**	**3,180**

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, 2019	51,807	24,551	76,358	1,368	418	1,786	2,205	974	3,180
Production	(8,847)	-	(8,847)	(238)	-	(238)	(270)	-	(270)
Technical revisions	8,695	(6,217)	2,478	273	(97)	176	349	81	430
Extensions and improved recovery	1,224	983	2,208	1	-	2	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(978)	(1,301)	(2,278)	(3)	(1)	(4)	(88)	(60)	(148)
Economic factors	(4)	7	3	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2020	**51,898**	**18,023**	**69,921**	**1,402**	**321**	**1,722**	**2,196**	**996**	**3,192**

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, 2019	1,638	823	2,461	20,286	10,857	31,143
Production	(342)	-	(342)	(3,460)	-	(3,460)
Technical revisions	389	(107)	282	1,932	(1,639)	293
Extensions and improved recovery	80	60	140	833	929	1,762
Acquisitions	-	-	-	-	-	-
Dispositions	(33)	(98)	(132)	(412)	(612)	(1,024)
Economic factors	-	-	1	-	2	1
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2020	**1,732**	**678**	**2,410**	**19,177**	**9,537**	**28,714**

UNITED STATES	**Tight Oil**			**Conventional Natural Gas**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2019	71	393	464	129	695	824
Production	(46)	-	(46)	(98)	-	(98)
Technical revisions	238	(243)	(5)	461	(412)	49
Extensions and improved recovery	-	-	-	-	-	-
Acquisitions	50	28	77	155	87	241
Dispositions	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2020	**314**	**178**	**491**	**646**	**369**	**1,016**

UNITED STATES	**Natural Gas Liquids**			**Total Oil Equivalent**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2019	-	-	-	93	509	602
Production	(2)	-	(2)	(64)	-	(64)
Technical revisions	3	1	4	318	(311)	8
Extensions and improved recovery	-	-	-	-	-	-
Acquisitions	9	4	13	84	46	130
Dispositions	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2020	**10**	**5**	**15**	**431**	**244**	**676**

TOTAL	**Light and Medium Oil**			**Tight Oil**			**Heavy 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, 2019	5,789	4,284	10,073	981	748	1,729	2,719	1,072	3,790
Production	(953)	-	(953)	(182)	-	(182)	(470)	-	(470)
Technical revisions	69	(153)	(85)	243	(355)	(112)	(84)	(228)	(312)
Extensions and improved recovery	276	610	886	8	4	12	265	90	355
Acquisitions	-	-	-	50	28	77	-	-	-
Dispositions	(128)	(175)	(303)	-	-	-	(72)	(112)	(184)
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2020	**5,052**	**4,567**	**9,619**	**1,100**	**425**	**1,525**	**2,358**	**822**	**3,180**

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, 2019	51,936	25,246	77,182	1,368	418	1,786	2,205	974	3,180
Production	(8,945)	-	(8,945)	(238)	-	(238)	(270)	-	(270)
Technical revisions	9,156	(6,630)	2,526	273	(97)	176	349	81	430
Extensions and improved recovery	1,224	983	2,208	1	-	2	-	-	-
Acquisitions	155	87	241	-	-	-	-	-	-
Dispositions	(978)	(1,301)	(2,278)	(3)	(1)	(4)	(88)	(60)	(148)
Economic factors	(4)	7	3	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2020	**52,544**	**18,393**	**70,937**	**1,402**	**321**	**1,722**	**2,196**	**996**	**3,192**

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, 2019	1,638	823	2,461	20,379	11,366	31,744
Production	(344)	-	(344)	(3,524)	-	(3,524)
Technical revisions	392	(106)	286	2,250	(1,950)	300
Extensions and improved recovery	80	60	140	833	929	1,762
Acquisitions	9	4	13	84	46	130
Dispositions	(33)	(98)	(132)	(412)	(612)	(1,024)
Economic factors	-	-	1	-	2	1
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2020	**1,742**	**683**	**2,425**	**19,609**	**9,781**	**29,390**

(1) Columns may not add due to rounding.
(2) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

Undeveloped Reserves

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

At December 31, 2020, proved net undeveloped reserves assigned in the Trimble Report were 13% of the total proved net reserves assigned. 90% of the proved net undeveloped reserves fall within eight 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% 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 39% of proved undeveloped reserves, future development is forecasted at an average of 73 locations per year over five years to match recent historical drilling results.

At December 31, 2020, probable net undeveloped reserves assigned in the Trimble Report were 16% of the total proved plus probable net reserves assigned. 91% of the probable net undeveloped reserves fall within six 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. 20% 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 50% of probable undeveloped reserves have been scheduled at an average of three locations per year from 2021 to 2024 and an average of 73 locations per year from 2025 to 2030 to maintain a total Proved and Probable drilling pace in Dodsland consistent with recent historical drilling in the area. The Trimble Report did not evaluate or otherwise include the Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

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, 2020, 2019, and 2018, based on forecast prices and costs:

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

Year	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
2018	24	17	104	5
2019	1,155	135	720	21
2020	201	98	208	12
Total Booked for Current Year	1,606	250	3,775	78

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

Year	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
2018	86	11	243	17
2019	2,229	62	1,281	47
2020	605	44	372	20
Total Booked for Current Year	3,533	193	4,905	187

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 had 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 6.3 million gross acres at December 31, 2020, prior to the completion of the U.S. Royalty Transaction. As at December 31, 2020, the majority of our land (75%) was 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 2020 were in alphabetic order: Bonterra Energy Corp., Corex Resources Ltd., Crescent Point Energy Corp., Karve Energy Inc., 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. As of December 31, 2020, we take in-kind and market approximately 16% of our total royalty production using 30-day contracts.

Approximately 99% 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

On 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 2020, this category of land accounted for approximately 16% of our total royalty acreage and provided approximately 43% 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% multiplied by 20%) of the oil or natural gas produced for the period.

Our mineral title lands encompass approximately 1,018,500 acres, of which 44% are leased and 56% are unleased. The mineral title lands also include approximately 570,000 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 880 acres, of which 100% are leased and developed. The leases form part of twenty-four drilling units, overlaying 19,139 gross drilling unit acres.

We also hold mineral title interests in potash, as described below under the heading "*Description of Royalty Lands – Potash*".

Royalty Assumption Lands

In Canada, we hold royalty interests in approximately 90,000 gross acres of royalty assumption 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 2020, 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 5.2 million acres, of which approximately 1.6 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 2020, this category of land accounted for approximately 82% of our total royalty acreage and provided approximately 49% 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.

As at December 31, 2020, we did 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.

In 2020, this category of royalty interests provided approximately 7% of our royalty revenue.

We do not have production volume royalties in the United States.

Description of Royalty Lands

Our royalty interests represent a geologically and geographically diverse portfolio of properties.

The following table summarizes, by area, our average royalty interest, net reserves and reserves value as at December 31, 2020, wells drilled, oil and natural gas production, and royalty operating income for 2020 for our Royalty Lands:

Year ended December 31, 2020		Alberta West	Saskatchewan East	North Dakota	Total[3]
Average royalty interest [1]	(%)	2.4	2.1	0.9	2.2
Wells drilled	(gross)	149	223	-	372
Royalty operating income[2]	($000s)	41,658	42,634	2,139	86,431
Average net daily production	(boe/d)	6,283	3,150	172	9,605
Oil and NGL	(bbls/d)	2,298	2,860	136	5,294
Natural gas	(Mcf/d)	23,911	1,744	213	25,868
Net proved reserves	(Mboe)	13,032	6,096	432	19,559
Oil and NGL	(Mbbls)	4,381	5,534	324	10,239
Natural gas	(MMcf)	51,906	3,368	646	55,920
Net proved plus probable reserves	(Mboe)	17,856	10,782	676	29,314
Oil and NGL	(Mbbls	6,337	9,884	507	16,728
Natural gas	(MMcf)	69,116	5,383	1,016	75,514
Future Net Revenue[1][2]					
Discounted at 10% per year	($000s)	267,133	340,443	18,448	626,023
	(% of total)	43	54	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.
(3) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

The following table summarizes, by region, the gross royalty acreage with respect to our Royalty Lands, as at December 31, 2020:

Area	Developed Gross Acres	Undeveloped Gross Acres(1)	Total Gross Acres
Alberta West	3,291,169	1,570,434	4,861,603
Saskatchewan East	727,880	702,886	1,430,766
North Dakota	882	-	882
Potash	10,217	8,325	18,542
Total(2)	4,030,148	2,281,645	6,311,793

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

(2) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

Alberta West

In 2020, 40% 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 continued development drilling in the Clearwater play. In this area, 100% of the wells are horizontal drills and over 95% of the wells targeted oil. Cardium drilling resulted in 36 gross wells, or 24% of gross wells drilled in the area. Mannville drilling resulted in 44 gross wells, or 30% of gross wells drilled in Alberta West. The emerging Clearwater play saw 13 gross wells drilled in 2020, or 9% of Alberta West drilling.

Saskatchewan East

In 2020, 60% 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). In this area, 100% of the wells are horizontal drills targeting oil plays.

In 2020, 41% 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, and the Shaunavon and Cantaur plays in southwest Saskatchewan. Together, these plays accounted for 59% of the gross royalty drilling in Saskatchewan East in 2020. Freehold continues to see the benefit of well-capitalized and active operators pursuing high netback opportunities in this area.

United States

In 2020, Freehold acquired approximately 130 net acres of mineral title interests, increasing its total acreage to approximately 880 net acres, with exposure to approximately 19,000 gross drilling unit acres and a royalty interest in 74 producing wells. The primary plays of value in North Dakota are the Bakken and Three Forks, with development occurring exclusively through horizontal drilling. Freehold has strategically positioned itself to acquire acreage under well-capitalized operators pursuing high netbacks in this area.

Following the year ended December 31, 2020, Freehold acquired the Acquired U.S. Royalty Assets, which included exposure to approximately 400,000 gross drilling unit acres of mineral title and overridng royalty interests across 12 basins and eight states and a royalty interest in approximately 1,800 producing wells. The Trimble Report did not evaluate or otherwise include the Acquired U.S. Royalty Assets and the amounts set forth in the Statement do not include any amount associated with the Acquired U.S. Royalty Assets. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

Potash

Our potash acreage inventory remains at approximately 18,500 gross acres in 2020. 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. In 2020, we received approximately $1.0 million from the production of approximately ten tonnes per day of potash. Our interests in potash reserves are an important non-fossil fuel revenue source, however they are not deemed material and as such an 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 2.2 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 undeveloped lands are leased and a well is drilled on land adjacent to the 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)(2) (gross wells)	2020	2019
Oil wells	316	566
Natural gas wells	7	15
Service/other wells	49	58
Dry and abandoned wells	-	2
Total	372	641
Success rate	100%	100%

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

(2) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

Working Interest Properties

In Canada, we own minor working interests in oil and natural gas properties. In 2020 Freehold closed a significant working interest disposition, selling its interest in 745 gross (62 net) wells which contributed approximately 250 boe/d of production at the time of the disposition. Production from the remaining working interest properties averaged 175 boe/d in 2020, down from 400 boe/d in 2019 and is comprised of approximately 35% oil and NGL and 65% natural gas. In 2020, we did not participate in any working interest drilling activity.

In 2021, it is expected that less than $1.0 million will be directed toward reclamation activities, with the focus on site restoration for previously abandoned wells.

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, 2020:

Royalty Lands	Natural Gas Wells	Oil Wells
Canada		
Alberta	16,558	12,559
Saskatchewan	1,048	12,438
British Columbia	195	139
Manitoba	-	372
Ontario	246	-
Canada Total	18,047	25,508
United States		
North Dakota	-	74
Total(1)	18,047	25,582

(1) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
Working Interest Properties	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1	0.8	-	-	21	11.6	-	-
Saskatchewan	1	0.4	-	-	-	-	-	-
British Columbia	-	-	-	-	-	-	-	-
Manitoba	-	-	-	-	-	-	-	-
Ontario	-	-	-	-	-	-	-	-
Total(1)(2)	2	1.1	-	-	21	11.6	-	-

(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, 2020:

	Undeveloped Acres		
	Royalty Lands	Working Interest Lands	
	Gross	Gross	Net
Canada			
Alberta	1,534,808	6,258	4,217
Saskatchewan	600,753	515	1,556
British Columbia	35,627	2,753	83
Manitoba	28,559	-	-
Ontario	81,899	-	-
Canada Total	2,281,646	9,526	5,856
United States			
North Dakota	-	-	-
Total(1)	2,281,646	9,526	5,856

(1) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

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 140,000 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 2020 was approximately 25% (2019 – 27%) and the rate for 2021 and future years is currently 24%. 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 2020. 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, 2020, Freehold's tax pools were $775 million (additional information is provided in Freehold's management's discussion and analysis for the year ended December 31, 2020 which is available on SEDAR at www.sedar.com).

Freehold’s corporate income tax filings for 2015, 2018, and 2019 were reassessed by the CRA in 2020 (the "**Reassessments**"). Pursuant to the Reassessments, deductions of $92.6 million of non-capital losses by

Freehold were denied, resulting in reassessed taxes, interest, and penalties totaling $29.3 million in addition to a denial of $129.9 million of carried forward non-capital losses. Freehold has filed its objection of the Reassessments which required deposits totaling $14.7 million that have been provided to the CRA. Freehold has received legal advice that it should be entitled to deduct the non-capital losses and as such, management remains of the opinion that all tax filings to date were filed correctly and that it expects to be successful in its objection of these Reassessments and therefore the payment of these deposits held by the CRA should be refunded, plus interest, and the denied non-capital losses should be reinstated.

The outcome of Freehold's objection to the Reassessments, 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 maintain or improve production. Freehold may finance capital expenditures from additional issuances of Common Shares, borrowings, farmouts or with working capital.

Freehold did not incur any Canadian development activity expenditures during the year ended December 31, 2020. Rather, capitalized Canadian expenditures for this period included capitalized general and administrative costs in addition to an adjustment for a previously acquired gross overriding royalty. The following table summarizes capital expenditures in the United States to acquire royalty lands:

	($000s)
Property acquisition costs[1]	
Proved properties	3,310
Undeveloped/unproved properties	-
Development costs	-
Total [2][3]	3,310

(1) As classified at the time of the acquisition.
(2) We did not incur any exploration costs in 2020.
(3) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

Production Estimates

The following tables set out the volume of gross and net production estimated for the year ended December 31, 2021 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

Reserves Category	Light and Medium Oil Gross (bbls/d)	Light and Medium Oil Net (bbls/d)	Tight Oil Gross (bbls/d)	Tight Oil Net (bbls/d)	Heavy Oil Gross (bbls/d)	Heavy Oil Net (bbls/d)
Proved						
Developed producing	-	1,897	-	331	2	1,025
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	333	-	13	-	62
Total proved	-	2,230	-	344	2	1,087
Probable	-	174	-	18	-	67
Total proved plus probable(1)	-	2,403	-	362	2	1,154

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	179	19,967	-	459	-	590
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,130	-	-	-	58
Total proved	179	21,097	-	459	-	648
Probable	5	649	-	6	-	147
Total proved plus probable(1)	184	21,746	-	465	-	795

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	9	725	41	7,481
Developed non-producing	-	-	-	-
Undeveloped	-	30	-	636
Total proved	9	756	41	8,117
Probable	-	34	1	426
Total proved plus probable(1)	10	790	42	8,543

UNITED STATES[2]

Reserves Category	Tight Oil Gross (bbls/d)	Tight Oil Net (bbls/d)	Conventional Natural Gas Gross (Mcf/d)	Conventional Natural Gas Net (Mcf/d)
Proved				
Developed producing	-	88	-	188
Developed non-producing	-	-	-	-
Undeveloped	-	21	-	37
Total proved	-	109	-	225
Probable	-	10	-	19
Total proved plus probable[1]	-	119	-	243

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	-	3	-	122
Developed non-producing	-	-	-	-
Undeveloped	-	-	-	27
Total proved	-	3	-	150
Probable	-	-	-	13
Total proved plus probable[1]	-	3	-	163

TOTAL[2]

Reserves Category	Light and Medium Oil Gross (bbls/d)	Light and Medium Oil Net (bbls/d)	Tight Oil Gross (bbls/d)	Tight Oil Net (bbls/d)	Heavy Oil Gross (bbls/d)	Heavy Oil Net (bbls/d)
Proved						
Developed producing	-	1,897	-	420	2	1,025
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	333	-	34	-	62
Total proved	-	2,230	-	453	2	1,087
Probable	-	174	-	28	-	67
Total proved plus probable[1]	-	2,403	-	481	2	1,154

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	179	20,155	-	459	-	590
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,166	-	-	-	58
Total proved	179	21,322	-	459	-	648
Probable	5	668	-	6	-	147
Total proved plus probable[1]	184	21,989	-	465	-	795

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	9	728	41	7,603
Developed non-producing	-	-	-	-
Undeveloped	-	30	-	663
Total proved	9	759	41	8,267
Probable	-	34	1	440
Total proved plus probable[1]	10	793	42	8,706

(1) Columns may not add due to rounding

(2) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

Production History

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

CANADA

	2020 Quarter Ended				2019 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)	3,046	3,303	3,254	3,732	4,008	3,709	3,790	3,800
Heavy Crude Oil (bbls/d)	1,173	791	920	1,300	1,178	1,261	1,084	1,057
Conventional Natural Gas[(3)] (Mcf/d)	26,295	24,510	25,503	29,086	27,786	27,609	28,768	28,938
NGL (bbls/d)	822	857	786	896	827	773	995	947
Combined (boe/d)	9,424	9,035	9,211	10,776	10,645	10,345	10,664	10,627
Average price realized								
Light and Medium Crude Oil[(2)] ($/bbl)	49.00	42.83	28.23	45.31	66.03	62.85	70.28	61.59
Heavy Crude Oil ($/bbl)	31.02	49.37	18.61	27.46	53.51	54.79	61.15	50.88
Conventional Natural Gas[(3)] ($/Mcf)	2.07	1.75	1.44	1.42	2.13	0.87	0.71	2.18
NGL ($/bbl)	26.87	21.25	15.27	27.06	30.66	27.78	29.60	36.76
Combined ($/boe)	27.82	26.74	17.14	25.08	36.69	33.62	35.88	36.29
Royalty expense[(4)]								
Light and Medium Crude Oil[(2)] ($/bbl)	-	-	0.06	0.05	0.09	0.09	0.11	0.02
Heavy Crude Oil ($/bbl)	0.02	(0.22)	(0.02)	0.19	0.01	0.33	0.54	0.51
Conventional Natural Gas[(3)] ($/Mcf)	-	-	0.03	(0.02)	(0.01)	0.02	-	0.01
NGL ($/bbl)	0.11	0.15	0.07	0.16	0.19	0.29	0.14	0.09
Combined ($/boe)	0.01	-	0.10	0.01	0.02	0.15	0.11	0.09
Operating expenses ($/boe)[(5)]								
Light and Medium Crude Oil[(2)] ($/bbl)	0.10	(0.01)	0.42	0.40	0.50	0.66	0.63	0.53
Heavy Crude Oil ($/bbl)	0.36	0.89	2.42	3.80	3.96	3.63	4.44	5.92
Conventional Natural Gas[(3)] ($/Mcf)	0.08	0.06	0.07	0.14	0.16	0.08	0.12	0.07
NGL ($/bbl)	0.30	0.56	0.49	0.44	0.77	0.46	0.57	0.36
Combined ($/boe)	0.33	0.30	0.61	1.01	1.08	0.93	1.05	1.01
Netback received[(6)(7)]								
Light and Medium Crude Oil[(2)] ($/bbl)	48.90	42.84	27.75	44.86	65.44	62.10	69.54	61.04
Heavy Crude Oil ($/bbl)	30.64	48.70	16.21	23.47	31.11	50.83	56.17	44.45
Conventional Natural Gas[(3)] ($/Mcf)	1.99	1.69	1.34	1.30	1.98	0.77	0.59	2.10
NGL ($/bbl)	26.46	20.54	14.71	26.46	29.70	27.03	28.89	36.31
Combined ($/boe)	27.48	26.44	16.43	24.06	35.58	32.53	34.72	35.19

(1) Represents net production from our Royalty Lands in Canada
(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)(2)]

	2020 Quarter Ended				2019 Quarter Ended			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average daily production[(3)]								
Tight Oil (bbls/d)	192	81	59	203	86	104	-	-
Conventional Natural Gas (Mcf/d)	360	147	74	274	55	137	-	-
NGL (bbls/d)	5	2	3	1	-	-	-	-
Combined (boe/d)	257	108	74	250	95	137	-	-
Average price realized								
Tight Oil ($/bbl)	47.62	51.37	19.21	58.65	81.65	63.03	-	-
Conventional Natural Gas ($/Mcf)	3.41	2.50	(5.68)	3.97	4.32	3.75	-	-
NGL ($/bbl)	14.14	11.78	5.31	25.28	13.51	-	-	-
Combined ($/boe)	40.69	42.34	9.86	52.18	76.02	53.34	-	-
Royalty expense[(4)]								
Tight Oil ($/bbl)	12.37	2.25	4.01	12.53	29.97	6.59	-	-
Conventional Natural Gas ($/Mcf)	0.05	0.05	0.07	0.07	-	-	-	-
NGL ($/bbl)	-	-	5.31	-	-	-	-	-
Combined ($/boe)	9.33	1.77	3.27	10.28	26.96	5.02	-	-
Operating expenses ($/boe)[(5)]								
Tight Oil ($/bbl)	-	-	-	-	-	-	-	-
Conventional Natural Gas ($/Mcf)	-	-	-	-	-	-	-	-
NGL ($/bbl)	-	-	-	-	-	-	-	-
Combined ($/boe)	-	-	-	-	-	-	-	-
Netback received[(6)]								
Tight Oil ($/bbl)	35.25	49.12	15.20	46.12	51.68	56.44	-	-
Conventional Natural Gas ($/Mcf)	3.36	2.45	(5.75)	3.90	4.32	-	-	-
NGL ($/bbl)	14.14	11.78	5.31	25.28	13.51	-	-	-
Combined ($/boe)	31.36	40.57	9.86	41.90	49.06	48.23	-	-

(1) Denominated in Canadian dollars.
(2) Does not include Acquried Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".
(3) Represents net production from our Royalty Lands in the United States.
(4) Royalty expense includes all royalty payments to federal and state governments and 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.

The following table summarizes our average daily production from important regions or fields for the year ended December 31, 2020:

	Light and Medium Oil(1) (bbls/d)	Heavy Oil (bbls/d)	Conventional Natural Gas(2) (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
Canada Royalty Lands(3)					
Alberta West	860	695	23,911	743	6,283
Saskatchewan East	2,455	323	1,744	82	3,150
Canada Total	3,315	1,018	25,655	825	9,433
United States Royalty Lands(3)					
North Dakota	134	-	213	2	172
Working Interest Properties(4)	-	45	690	16	176
Total(5)	3,449	1,063	26,558	843	9,781

(1) Includes an immaterial amount of production from tight oil reserves.
(2) Includes an immaterial amount of production from coal bed methane and shale gas reserves.
(3) Production from the Royalty Lands is presented on a net basis.
(4) All working interest properties are located in Canada.
(5) Does not include Acquired U.S. Royalty Assets, which were acquired subsequent to the year ended December 31, 2020. See "*General Development of the Business – Year Ended December 31, 2020*" and "*General Development of the Business – Recent Developments*".

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 2020, our working interest assets represented less than 1% of our total operating income and less than 2% 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..

Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs

For the purposes of estimating Reserves Data, abandonment, decommissioning and reclamation costs for all wells (both 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 capital costs associated with abandonment and reclamation reflected in the estimates of future net revenue associated with our proved reserves and proved plus probable reserves is approximately $11.5 million for both cases.

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, 2020 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 operating in the oil and gas industry in Canada are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government; and with respect to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Western Canadian oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted.

The Corporation's assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of the Corporation's and its royalty payors upstream oil and natural gas business include all manner of activities associated with the exploration for and production of 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, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct 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.

Outlined below are some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, specifically in the provinces of Alberta, Saskatchewan, British Columbia, and Manitoba, where as at December 31, 2020, the Corporation's assets were primarily located. While these matters 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 matters carefully.

In addition, the Corporation also holds interests in crude oil and natural gas properties, along with related assets, 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 as at December 31, 2020, the Corporation's interests in the United States represented an immaterial portion of the Corporation's total interests (less than 3% 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 the United States has not been included in this AIF.

As a result of the U.S. Royalty Transaction, the Corporation acquired additional royalty interests in the United States after December 31, 2020 and as a result going forward the conditions and regulations that impact the crude oil and natural gas industry in the United States will have a greater impact on the Corporation going forward. The Corporation will continue to assess and evaluate the conditions and regulations that impact the crude oil and natural gas industry in the United States and the impact such conditions and regulations have on the Corporation's ongoing business.

Pricing and Marketing in Canada

Crude Oil

Oil producers are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary determinant of oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Since early 2020, worldwide oversupply of oil, a lack of available storage capacity and decreased demand due to COVID-19 have had a significant impact on the price of oil. In an effort to stabilize global oil markets, the Organization of the Petroleum Exporting Countries and a number of other oil producing countries announced an agreement to cut oil production by approximately 10 million bbls/d in April 2020. This agreement contributed to rebalancing global oil markets by achieving approximately 99.5% compliance with the agreed production adjustment commitments. However, economic recovery has slowed due to a resurgence of COVID-19 and newly emerging virus variants in major economies.

Natural Gas

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

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms of sale.

Exports from Canada

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the *Canadian Energy Regulator Act* (the "**CERA**"). 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 federal government. The Corporation does not directly enter into contracts to export its production outside of Canada.

Transportation Constraints and Market Access

One constraint to the export of oil, natural gas and NGLs is the deficit of transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation and export projects are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Due, in part, 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 over the last several years.

Pipelines

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. 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 and the price received.

Under the Canadian Constitution, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and 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 also require approvals from several levels of government in the United States.

Specific Pipeline Updates

The Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, has faced significant delays due to permitting difficulties in the United States. However, Minnesota regulators approved the final required permit for the project in November 2020. Certain segments of the Line 3 Replacement in North Dakota and Wisconsin are currently in operation and the Canadian portion of the replaced pipeline began commercial operation in December 2019. Construction of the Line 3 Replacement in Minnesota began in early December 2020; Enbridge expects the line to be in service in the fourth quarter of 2021.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019 and it is expected to be in-service in December 2022.

On March 31, 2020, TC Energy Corporation ("**TC Energy**") announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US $1.1 billion equity investment in the project and would guarantee a US $4.2 billion project level credit facility. While construction on the Keystone XL Pipeline started in April 2020, the project remains subject to legal and regulatory barriers in the United States, including the cancellation of a presidential permit on January 20, 2021 that permits the Keystone XL Pipeline to operate across the international border.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, potentially forcing the lines comprising this segment of the pipeline system to be shut down by May 2021. Enbridge filed a federal complaint in late November 2020 in the Unites States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards.

Marine Tankers

The *Oil Tanker Moratorium Act*, which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines being built to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium.

Crude Oil and Bitumen by Rail

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020 that trains hauling more than 20 cars carrying dangerous goods, including oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in April 2020 and will remain in place until permanent rule changes are approved.

Natural Gas and LNG

Natural gas prices in Alberta and British Columbia have 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 infrastructure 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 relative to other markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline system (the "**NGTL System**") to prioritize deliveries into storage. The change stabilized supply and pricing, particularly during periods of maintenance on the system. TC Energy received Government of Canada approval for an expansion to the NGTL System in October 2020, with pipeline construction activities expected to begin in January 2021 and a target in-service date of April 2022. The CER has started a process to determine whether it will extend the temporary service protocol, announcing an extension to the review process in late October 2020.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

In late 2019, TC Energy announced that it would sell a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction closed in May 2020. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding.

In addition to LNG Canada and the CGL Pipeline projects, the following is an update on various other LNG Projects that have been proposed in Canada:

- 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. However, both partners are looking to sell some or all of their interest in the project.

- Woodfibre LNG Limited, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. has proposed to build the Woodfibre LNG Project, a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Commission approved a project permit for the Woodfibre LNG Project in July 2019 and a formal approval of the project is expected in the third quarter of 2021, with construction beginning shortly thereafter.

- GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026.

- Pieridae Energy Ltd.'s ("**Pieridae**") proposed Goldboro LNG project, located in Nova Scotia, 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, but Pieridae has delayed its final investment decision until mid-2021.

- Finally, Cedar LNG Export Development Ltd.'s Cedar LNG Project near Kitimat, British Columbia, is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office (the "**BC EAO**") conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier oil pipeline system. A common carrier pipeline must accept all products offered to it for transportation. If there is insufficient capacity to transport the volumes offered, the available capacity is pro-rated to accommodate all shippers. The changes that Enbridge intends to implement include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein shippers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. If the service change is approved, 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 first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. The regulatory hearing process is currently underway and a final decision from the CER is not expected until mid-2021. If Enbridge receives CER approval, it intends to hold the open season by the end of 2021.

Curtailment

In December 2018, the Government of Alberta announced that it would mandate a short-term and temporary curtailment of provincial oil and bitumen production. Curtailment first took effect on January 1, 2019. As contemplated in the *Curtailment Rules*, the Government of Alberta, on a monthly basis, required oil and bitumen producers producing more than 20,000 bbls/d to limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

As of December 2020, monthly oil production limits are no longer in effect. However, the *Curtailment Rules*, which were set to be repealed on December 31, 2020, have been extended such that the Government of Alberta retains the ability to impose production limits if needed.

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could have an impact on Western Canada's oil and gas industry at large, including the Corporation's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia and Europe.

Land Tenure

Mineral rights

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits (collectively, "**leases**") for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

In response to COVID-19, the governments of Alberta, British Columbia and Saskatchewan announced measures to extend or continue Crown leases that may have otherwise expired in the months following the implementation of pandemic response measures.

All 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 disposition. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences; British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned 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 companies seeking to explore for and/or develop oil and natural gas reserves.

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**") manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations. Until recently, oil and natural gas activities conducted on Indigenous reserve lands 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 and further regulations are currently being developed. The Corporation does not have operations on Indigenous reserve lands.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

Royalties and Incentives

General

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable.

Producers and working interest owners of oil and natural gas rights may create additional royalties or royalty-like interests, such as overriding royalties, net profits interests and net carried interests, through private transactions, the terms of which are subject to negotiation.

Occasionally, the provincial governments in Western Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the oil and gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic such as the various short-term loan programs and the Canada Emergency Wage Subsidy, for example, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, Innovation, Science and Economic Development Canada and, in some cases, the Canada Revenue Agency.

Alberta

Crown royalties

In Alberta, oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation.

In 2016, the Government of Alberta adopted a modernized Crown royalty framework (the "**Modernized Framework**") that applies to all conventional oil (i.e., not oil sands) and natural gas wells drilled after December 31, 2016 that produce Crown-owned resources. The previous royalty framework (the "**Old Framework**") will continue to apply to wells producing Crown-owned resources that were drilled prior to January 1, 2017 until December 31, 2026, following which time they 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.

Royalties on production from wells subject to the Modernized Framework are determined on a "revenue-minus-costs" basis. The cost component is based on a Drilling and Completion Cost Allowance formula that relies, in part, on the industry's average drilling and completion costs, determined annually by the AER, and incorporates information specific to each well such as vertical depth and lateral length.

Under the Modernized Framework, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable Drilling and Completion Cost Allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%.

Under the Old Framework, royalty rates for conventional oil production can be as high as 40% and royalty rates for natural gas production can be as high as 36%. Similar to the Modernized Framework, these rates vary based on the nature of the resource and market prices. The natural gas royalty formula also provides for a reduction based on the measured depth of the well, as well as the acid gas content of the produced gas.

Oil sands production in Alberta is also subject to a royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues and, depending on market prices, the applicable rates are capped at 9%. After payout, the royalty payable is the greater of the gross revenue royalty (described above) and a net revenue royalty based on rates that range from 25% - 40%.

In addition to royalties, producers of oil and natural gas from Crown lands in Alberta are also required to pay annual rentals to the Government of Alberta.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner.

The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

British Columbia

Crown royalties

Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. Producers of oil and natural gas receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales.

The Crown royalty rate for oil can be as high 40% and depends on factors such as the volume of oil produced from a particular well or unitized tract and its vintage. Royalty rates are reduced on certain wells, including low-productivity wells, to reflect higher per-unit costs of exploration and extraction. The Crown royalty rate for natural gas and NGLs in British Columbia varies depending on the characteristics of the specific substance and can be as high as 27%, depending on factors such as whether the gas is classified as conservation gas or non-conservation gas, the applicable reference price and select price.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in British Columbia also pay monthly freehold production taxes to the Government of British Columbia.

For 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. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax to the Government of British Columbia.

Saskatchewan

Crown royalties

Crown royalties payable on the production of oil and natural gas in Saskatchewan are paid on a well-by-well basis. Producers of oil and natural gas receive royalty invoices from the Government on a monthly basis.

The Crown royalty payable on oil production is paid on a well-by-well basis and depends on a number of variables, including the type and vintage of oil, the quantity of oil produced in a given month, the average wellhead price and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 5% - 20% and the marginal royalty rate ranges from 25% - 45%. The Crown royalty payable on natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type and classification of the natural gas, the finished drilling date of the well and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 0% - 20% and the marginal royalty rate ranges from 30% - 45%.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced. 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.

Resource Surcharge

In addition to royalties, certain entities operating in Saskatchewan must pay a tax, known as a "**Resource Surcharge**", on the value of resources sales. The Resource Surcharge rate is 3% of the sales value of all oil and natural gas produced from wells drilled in Saskatchewan before October 1, 2002, and 1.7% for any wells drilled thereafter.

Manitoba

Crown royalties

The Crown royalty payable on oil production in Manitoba depends on the classification of the oil, which depends on variables such as the age and characteristics of the well, including whether the well is a vertical or horizontal well. Based on these factors, the royalty rate can be as high as approximately 43% of monthly production from a well or allocated to a spacing unit or unit tract, as applicable. The Crown royalty payable on natural gas production is a flat 12.5% of monthly revenue.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale between 0% and approximately 40% and is based on monthly production volume and varies with the classification of the 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.

Regulatory Authorities and Environmental Regulation

General

The oil and gas industry in Canada and the United States is currently subject to environmental regulation under a variety of federal, provincial, state, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, 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, future changes to environmental legislation, including legislation related to air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO2e**")), may impose further requirements on operators and other companies in the oil and gas industry.

Canada

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

On August 28, 2019, the *Impact Assessment Act* (the "**IAA**") replaced the *Canadian Environmental Assessment Act, 2012*.

The enactment of the CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the IA Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IAA. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry 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 ("**GHG**") emissions caps and certain refining, processing and storage facilities.

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 Canadian federal government has stated should provide more certainty as to the length of the full review process. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA and the hearing is expected to take place in the first half of 2021.

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related statutes 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 Government of Alberta relies on regional planning to accomplish its 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. 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 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.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**") The Corporation does have royalty lands in all three of these regions. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") regulates conventional oil and natural gas producers, shale gas producers and other operators of oil and natural gas facilities in the province. Under the OGAA, the BC Commission has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives and requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and permits, licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The Government of British Columbia has introduced a regime to monitor and manage the risk of induced seismicity related to oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The *Drilling and Production Regulation* requires a producer to suspend its operations if they trigger an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC Commission before resuming production. In June 2016, the BC Commission amended the permitting process to require all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). The Corporation owns a very minor land position in this area. Permit holders in the Kiskatinaw Area are subject to additional requirements before they can conduct hydraulic fracturing operations, including developing a seismic monitoring and mitigation plan that is approved by the BC Commission, and notifying the BC Commission and local residents about planned hydraulic fracturing requirements. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BC Commission on demand. If a seismic event occurs, permit holders are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude and triggers a sliding scale of obligations from permit holders. The obligations range from reporting the earthquake and developing an approved protocol for subsequent earthquakes, to initiating such protocols, to suspending operations until permitted to resume by the BC Commission. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

An updated *Environmental Assessment Act* came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act*, the Government of British Columbia 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 BC EAO will consider the environmental, health, cultural, social and economic effects of a proposed project.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of oil and natural gas activities in the province. The *Oil and Gas Conservation Act* (the "**SKOGCA**") is the statute governing the regulation of resource development operations in the province, along with *The Oil and Gas Conservation Regulations, 2012* and *The Petroleum Registry and Electronic Documents Regulations*. 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 oil and natural gas resources. 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.

Liability Management Rating Program

Alberta

The AER administers a Liability Management Rating Program (the "**AB LMR Program**"), which is currently undergoing changes, including a name change to the "Liability Management Framework" (the "**AB LMF**"). The AB LMR Program is a liability management program governing most conventional upstream oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LFP**"), and the Licensee Liability Rating Program (the "**AB LLR Program**"). 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 licensee, must reduce its liabilities or provide the AER with a security deposit. Failure to do so 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**").

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 becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be bankrolled exclusively by licensees in the AB LLR Program and AB OWL Program who contribute to a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan fund approximately $335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In response to the increase in orphaned oil and gas sites and the environmental risks associated therewith, 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. 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 they can meet their abandonment and reclamation obligations, such as by posting security or reducing their existing obligations.

As a result of the Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision), 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 licence transfer when any such licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed the *Liabilities Management Statutes Amendment Act*, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct Licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. These changes will come into force on proclamation.

Additionally, the Government of Alberta announced in July 2020 that the AB LMF will replace the AB LMR Program and its constituent programs. Among other changes under the AB LMF, the AB LMR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LMR Program and establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of oil and gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets.

The Government of Alberta followed the announcement of the AB LMF with amendments to the *Oil and Gas Conservation Rules* and the *Pipeline Rules* in late 2020. The changes to these rules fall into three broad categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

The AER has published a draft of an amended Directive 067 to implement some of these changes (the "**Draft Directive**"), and has issued a call for feedback on the Draft Directive that will be open until mid-February 2021. The changes introduced by the Draft Directive include building on the AER's corporate and financial disclosure requirements for parties who wish to acquire, hold or transfer licences in Alberta, and broadening the AER's discretion to withhold or revoke licensees' privileges if they are assessed as posing an "unreasonable risk". The feedback that the AER receives will be considered in the determination of the final revised Directive 067, and the rollout of the AB LMF may require changes to other Directives as well. As a result, the ongoing and future transactions of the Corporation and its royalty payors may be affected in this period of transition, resulting in processing delays for licence transfers and regulatory uncertainty as the criteria and requirements for licensees are subject to change.

To address abandonment and reclamation liabilities in Alberta, the AER implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. Beginning in 2015, for example, the AER oversaw the Inactive Well Compliance Program, a five-year program intended to address the growing inventory of inactive and noncompliant wells in Alberta. More recently, 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. Parties seeking to participate in the program 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 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 liability management rating is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed their deemed assets (i.e., an LMR below 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

In the spring of 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 levy. The OGAA permits the BC Commission to impose more than one levy in a given calendar year.

The *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") establishes the first set of 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 the corresponding 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 takes on the obligation of 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. 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 Ministry 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. Further updates were published in Directive PNG025, which replaced Guideline PNG025.

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 licenced 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 or facility 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.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's oil and gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally provided funds through the Site Rehabilitation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund. The Government of British Columbia is disbursing its $120 million share of the federally provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation

Program and the Legacy Sites Reclamation Program. In Saskatchewan, $400 million in federal funding will be allocated through the Accelerated Site Closure Program ("**ASCP**"). The first phase of the ASCP will make $100 million available to eligible service companies to conduct abandonment and reclamation work. Further tranches of the ASCP, up to $300 million, will be made available in the future.

Climate Change Regulation

Climate change regulation at each of the international, federal, provincial and state levels has the potential to significantly affect the future of the oil and gas industry. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. 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 changes 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. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. Decisions about a prospective carbon market and emissions cuts until the next climate conference, scheduled to take place in November 2021.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, but indicated in its recent Speech from the Throne (also referred to as the "**Throne Speech**"; discussed in greater detail below) that it may implement policy changes to exceed this target. Specific details have not yet been announced.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. 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 output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of carbon dioxide equivalent ("**CO2e**") emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. This ensures that there is a uniform price on emissions across the country. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne of CO2e in 2022. On December 11, 2020, however, the federal government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Starting April 1, 2021, the minimum price permissible under the GGPPA is $40/tonne of CO2e.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In the Saskatchewan and Ontario references, the appellate Courts found the GGPPA to be constitutional; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments have been appealed to the Supreme Court of Canada. The hearing took place in September 2020, but the Court has not yet released its decision.

On April 26, 2018, the Canadian 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 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 the intentional venting of methane and ensure that 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. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

The Canadian federal government has enacted the *Multi-Sector Air Pollutants Regulation* under the authority of the *Canadian Environmental Protection Act, 1999*, which regulates certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced a $750 million Emissions Reduction Fund intended to support pollution reduction initiatives, including methane. Funds disbursed through this program will primarily take the form of repayable contributions to onshore and offshore oil and gas firms.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

In the September 23, 2020 Throne Speech, the federal government has indicated that it intends to make a number of investments that will help it achieve net-zero emissions by 2050, including investments intended to: (i) improve transit options; (ii) make zero-emissions vehicles more affordable; (iii) expand electric vehicle charging infrastructure across the country; (iv) launch a fund that will help attract investments in the development of zero-emissions technology, including a corporate tax cut of 50% for companies participating in this initiative; (v) develop a Clean Power Fund that will, in part, help regions transition to cleaner sources of power generation; and (vi) support continued investment in the development and implementation of renewable and clean energy technologies. Specific program details have not yet been announced.

On November 19, 2020, the federal government introduced the *Canadian Net-Zero Emissions Accountability Act* in Parliament. If passed, this Act will bind the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It will also establish rolling five-year emissions-reduction targets and require the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body and require the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making.

Alberta

In November 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed.

In June 2019, the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $30/tonne of CO2e and will increase to $40/tonne on April 1, 2021. In December 2019, the federal government approved Alberta's *Technology Innovation and Emissions Reduction* ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous *Carbon Competitiveness Incentives Regulation*.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. 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 aims to lower annual methane emissions by 45% by 2025. 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 the updated 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 Directives will support Alberta in achieving its 2025 goal. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

British Columbia

In August 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 fuel charge. The fuel charge is currently set at $40/tonne of CO2e. In response to COVID-19, the Government of British Columbia has delayed the scheduled increase to $45/tonne of CO2e until April 1, 2021.

In January 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.

In December 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 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.

In January 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. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia.

Saskatchewan

In May 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The government subsequently released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* ("**Prairie Resilience**"), outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

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 reduce 4.5 million tonnes of CO2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO2e by 2030.

In April 2019, Saskatchewan produced its first annual report on climate resilience. The report measures the Province's progress on goals set out under Prairie Resilience. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented *Directive PNG017: Measurement Requirements for Oil and Gas Operations*, which came into force in December 2019 and was amended in April 2020, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Saskatchewan.

Manitoba

In 2018, the Government of Manitoba unveiled the *Climate and Green Plan Implementation Act*. The Act included a new *Climate and Green Plan Act*, a new *Industrial Greenhouse-Gas Emissions Control and Reporting Act* and various related amendments to existing legislation. In March 2020, the Government of Manitoba introduced the *Climate and Green Plan Implementation Act, 2020*, which, among other things, introduced a $25/tonne of CO2e charge.

The original *Climate and Green Plan Implementation Act* also required the Government of Manitoba to establish five-year emissions reduction targets. In June 2019, the Government of Manitoba announced a GHG emissions reduction target of one megatonne for the 2018-2022 period.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the *United Nations Declaration of the Rights of Indigenous Peoples* ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* (the "**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In December 2020, the federal government introduced *Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act* ("**Bill C-15**"). Similar to British Columbia's DRIPA, the intention of Bill C-15, if passed, is to establish a process whereby the Government of Canada will take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

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*" and "*Risk Factors – Impact of Pandemics*". 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 –Royalty Regimes*", "*Risk Factors – Regulatory*", "*Risk Factors – Environmental*" and "*Risk Factors – Climate Change*". In addition, the difficulties encountered by midstream proponents to obtain on a timely basis the necessary approvals 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 Facility Arrangements*". 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. 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, the ongoing COVID-19 pandemic, 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.

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.

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

Impact of Pandemics

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide, including COVID-19 or any other similar illnesses, could have an adverse impact on the Corporation's results, business, financial condition or liquidity.

On March 11, 2020, the World Health Organization declared the outbreak of a strain of novel coronavirus disease, COVID-19, a global pandemic. The COVID-19 pandemic has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. Unexpected developments in financial markets, regulatory environments, or consumer behaviour may also have adverse impacts on the Corporation's results, business, financial condition or liquidity, for a substantial period of time.

The COVID-19 pandemic has also created additional operational risks for the Corporation, including the need to provide enhanced safety measures for its employees and customers; comply with rapidly changing regulatory guidance; address the risk of, attempted fraudulent activity and cybersecurity threat behaviour; and protect the integrity and functionality of the Corporation's systems, networks, and data as a larger number of employees work remotely. The Corporation is also exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures implemented in response to the COVID-19 pandemic, as well as the potential for a significant proportion of the Corporation's employees, including key executives, to be unable to work effectively, because of illness, quarantines, sheltering-in-place arrangements, government actions or other restrictions in connection with the pandemic.

The extent to which the COVID-19 pandemic continues to impact the Corporation's results, business, financial condition or liquidity will depend on future developments in Canada, the U.S. and globally, including the development and widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the U.S., the ongoing evolution of the development and distribution of an effective vaccine also continues to raise uncertainty.

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 – Regulatory Authorities and Environmental Regulation - 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. During its tenure, the former American administration withdrew the United States from the Trans-Pacific Partnership and passed sweeping tax reform, which, among other things, significantly reduced U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The former U.S. administration also took action to reduce regulation, which affected relative competitiveness of other jurisdictions.

In addition, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") was ratified on July 1, 2020 and may impact the Corporation's business. See "*Industry Conditions – International Trade Agreements*".

The newly-inaugurated Biden administration in the U.S. has indicated that it will roll-back certain policies of the former administration, and has taken action to cancel TC Energy Corporation's Keystone X.L. pipeline permit. While it is unclear which other legislation or policies of the former Trump administration will be rolled-back and if such roll-backs will be a priority of the new administration in light of the ongoing COVID-19 pandemic, any future actions taken by the new U.S. administration could 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 changing political landscape in the United States, the impact of the United Kingdom's exit from the European Union are slowly emerging and some impacts may not become apparent for some time. 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 ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy.

The United Conservative Party government in Alberta is supportive of the Trans Mountain Pipeline expansion project and, although there has been notable opposition from the government of British Columbia, the federal Government remains in support of the project. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdictions where the Corporation is active. See "*Industry Conditions – Transportation Constraints and Market Access*".

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.

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation - Climate Change Regulation*", "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – International 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. In August 2019, the Canadian Energy Regulator Act and the Impact Assessment Act came into force, resulting in changes to the federal regulation and associated environmental assessments of major projects. 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.

In January 2021, U.S President Biden took steps to cancel the presidential permit that had allowed the Keystone XL Pipeline to operate across Canadian and American borders. It is unclear if challenges to the revocation of the permit will be successful and what the direct impact of the loss of permit will be on the Corporation.

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*".

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 applies in provinces and territories that request it to be implemented or are without their own system that meets federal standards. The federal regime was subject to a number of court challenges by Alberta, Saskatchewan and Ontario. The final decision from the Supreme Court of Canada is expected to be delivered sometime in 2021. 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 are currently underway. In July 2020, the Government of Alberta announced that the AB LMR and associated programs will be replaced by the AB LMF. 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. As a result of the decision, the Government of

Alberta implemented the *Liabilities Management Statutes and Amendment Act*, which places the financial burden of a defunct licensee's abandonment and reclamation obligations on the working interest partners of the defunct Licensee and may order the AER's Orphan Fund to assume custody of wells or sites without a responsible owner to expedite the cleanup process.

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 recent years, climate change advocacy groups have attempted to bring legal action against various levels of the government for climate related matters.

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 ongoing COVID-19 pandemic has increased the prevalence of cyber-attacks, as increased malicious activities are creating more threats for cyberattacks including COVID-19 phishing emails, malware-embedded mobile apps that purport to track infection rates, and targeting of vulnerabilities in remote access platforms as many companies continue to operate with work from home arrangements.

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 131,435,334 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
2020				
January	8.18	7.01	7.06	16,660,211
February	7.44	5.76	6.02	9,847,376
March	6.46	2.30	2.94	25,289,694
April	4.15	2.75	3.73	17,572,733
May	4.03	3.34	3.60	11,480,801
June	4.43	3.19	3.52	20,876,291
July	3.93	3.36	3.58	8,448,204
August	4.75	3.60	4.16	9,926,964
September	4.25	3.65	3.69	8,656,066
October	4.09	3.37	3.69	8,036,074
November	5.23	3.65	5.07	10,554,531
December	5.94	4.96	5.21	10,233,723
2021				
January	6.30	5.18	5.48	9,036,383
February	7.37	5.51	6.90	11,196,874
March 1-3	7.32	6.87	7.23	1,407,488

Prior Sales

Other than Deferred Share Units, Freehold did not issue any securities of a class that are not listed or quoted on market place during the year ended December 31, 2020. 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, 2020:

Date	Numbered Deferred Share Units	Deemed Price per Deferred Share Unit
January 1, 2020	66,529	$7.29
January 15, 2020	1,582 (1)	$7.84
February 15, 2020	2,220 (1)	$7.20
March 15, 2020	4,293 (1)	$3.75
April 15, 2020	5,038 (1)	$3.24
May 15, 2020	1,382 (1)	$3.43
June 15, 2020	1,356 (1)	$3.51
July 15, 2020	1,317 (1)	$3.63
August 15, 2020	1,039 (1)	$4.62
September 15, 2020	1,277 (1)	$3.77
October 15, 2020	1,328 (1)	$3.64
November 15, 2020	1,096 (1)	$4.43
December 15, 2020	864 (1)	$5.64

(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.

Divends

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, 2020, our legal stated capital was $126 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, 2021, Freehold has declared a cash dividend of $0.02 per Common Share for Shareholders of record on January 31, 2021, which was paid on February 16, 2021, has declared a cash dividend of $0.02 per Common Share for Shareholders of record on February 28, 2021, which is payable on March 15, 2021, and has declared a cash dividend of $0.03 per Common Share for Shareholders of record on March 31, 2021, which is payable on April 15, 2021.

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
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

Record Date	Payment Date	Cdn$ per Share
2020		
January 31, 2020	February 18, 2020	0.0525
February 29, 2020	March 16, 2020	0.0525
March 31, 2020	April 15, 2020	0.0525
April 30, 2020	May 15, 2020	0.0150
May 31, 2020	June 15, 2020	0.0150
June 30, 2020	July 15, 2020	0.0150
July 31, 2020	August 17, 2020	0.0150
August 31, 2020	September 15, 2020	0.0150
September 30, 2020	October 15, 2020	0.0150
October 31, 2020	November 16, 2020	0.0150
November 30, 2020	December 15, 2020	0.0150
December 31, 2020	January 15, 2021	0.0200
		0.2975

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 22.04% 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, 2021, 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

Name and Province of Residence	Position with Freehold	Principal Occupation	Director Since
Marvin Romanow Alberta, Canada	Chair of the Board	Corporate Director	May 14, 2015
David M. Spyker(6) Alberta, Canada	President and Chief Executive Officer and Director	President & Chief Executive Officer of Rife	January 20, 2021
Aidan M. Walsh(1)(3) Alberta, Canada	Director	Corporate Director	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 5, 2020 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.
(6) Appointed January 20, 2021 concurrent with his appointment as President and Chief Executive Officer and is expected to be put forward as a nominee of the Manger at the next annual meeting of Shareholders pursuant to the Governance Agreement.

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
David M. Spyker Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer of Rife	November 28, 2016
David W. Hendry Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice-President, Finance and Chief Financial Officer of Rife	December 1, 2019
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
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, 2021, the directors and senior officers of Freehold, as a group, beneficially owned or controlled, directly or indirectly, 396,686 Common Shares or less than 1% of the issued and outstanding Common Shares. CN Pension Trust Funds, owned, directly or indirectly, 28,969,931 Common Shares (approximately 22.0%) as at March 4, 2021. From 1996 to March 4, 2021, the Manager has received 3,700,450 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, MEG Energy Corporation, and Precision Drilling Corporation.

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 a Corporate Director. Prior to April 30, 2020 he was 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 43 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 a former director and Chair of the Explorers and Producers Association of Canada (EPAC).

David M. Spyker

David Spyker was appointed President and Chief Executive Officer in January 2021. From September 2020 to January 2021 Mr. Spyker served as Freehold's Interim President and Chief Executive Officer. Mr. Spyker joined Rife in November 2016 as Vice-President, Production and was appointed Chief Operating Officer in March 2019. Prior to joining Rife, he held various roles at Anderson Exploration Ltd., Anderson Energy Ltd., and Anderson Energy Inc. Mr. Spyker has over 30 years of industry experience. He holds a Bachelor of Science degree in Mechanical Engineering from the University of Alberta and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

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.

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 HR 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).

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 information circular, 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.

Mr. Harrison was a director of Delphi Energy Corp. ("**Delphi**") and resigned on September 23, 2019. On April 14, 2020, Delphi commenced proceedings under the *Companies' Creditors Arrangement Act*.

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 "*Directors and Officers*".

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	
	2020	2019
Audit fees(1)	207,580	210,332
Audit-related fees(2)	-	-
Tax fees(3)	51,181	12,500
All other fees(4)	96,300	-
Total	355,061	222,832

(1) 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.

(3) Tax fees consist of fees for tax compliance, tax preparation and advisory services. During 2020 and 2019, $12,500 and $12,500, respectively, of such fees were related to tax compliance and tax preparation and the remainder was for advisory services.

(4) The services provided in this category includes work performed by Freehold's external auditors in connection with the bought deal financing completed by Freehold in January 2021.

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, 2020, Rife had 78 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 2018, 2019 and 2020 an aggregate of 220,000, 220,000 and 165,000

Common Shares, respectively, were issued to the Manager as payment of the Management Fee. As at December 31, 2020, the quarterly Management Fee was 41,250 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 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 2020 – 54%). 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 2020, a total of 308,167 (2019 – 100,275) restricted awards and 363,480 (2019 – 106,919) performance awards were granted to employees of Rife under the Freehold incentive award plan reflecting Freehold's 48% (2019 – 48%) of long-term incentive compensation granted to Rife employees in 2020. 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 (2020 – 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
David M. Spyker Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer of Rife	November 28, 2016
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
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
Karen C. Taylor Alberta, Canada	Corporate Secretary	Corporate Secretary of Rife	February 1, 2008

As at March 4, 2021, the directors and senior officers of the Manager as a group beneficially owned, directly or indirectly, or exercised control or direction over 111,816 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.

Freehold’s corporate income tax filings for 2015, 2018, and 2019 were reassessed by the CRA in 2020 pursuant to the Reassessments. Pursuant to the Reassessments, deductions of $92.6 million of non-capital losses by Freehold were denied, resulting in reassessed taxes, interest, and penalties totaling $29.3 million in addition to a denial of $129.9 million of carried forward non-capital losses.

Freehold has filed its objection of the Reassessments which required deposits totaling $14.7 million that have been provided to the CRA. Freehold has received legal advice that it should be entitled to deduct the non-capital losses and as such, management remains of the opinion that all tax filings to date were filed correctly and that it expects to be successful in its objection of these Reassessments and therefore the payment of these deposits held by the CRA should be refunded, plus interest, and the denied non-capital losses should be reinstated.

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.

As described under "*General Development of Business – Year Ended December 31, 2020*", as part of the Financing, CN Pension Trust Funds through Rife purchased 2,791,667 Subscription Receipts at a price of

$4.80 per Subscription Receipt for gross proceeds of approximately $13.4 million on a non-brokered private placement basis.

The Manager and Rife are wholly-owned subsidiaries of the CN Pension Trust Funds, which held, directly or indirectly, 28,969,931 Common Shares as at March 4, 2021, representing approximately 22.04% 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 2020 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 "*Directors and Officers – 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 "*Borrowings*".

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 22, 2021, which relates to our Annual and Special Meeting of Shareholders to be held on May 11, 2021. Additional financial information is provided in Freehold's consolidated financial statements for the year ended December 31, 2020 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, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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, 2020, 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) Including Inactive Costs and Capital ($000s)			
			Audited	Evaluated	Reviewed	Total
Trimble Engineering Associates Ltd.	Reserve and Present Worth Appraisal of Certain Oil and Gas Properties At December 31, 2020 Dated January 29, 2021	Canada & United States	$0	$617,578	$0	$617,578

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 4, 2021.

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

Freehold ROYALTIES LTD.

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) "*David M. Spyker*"
David M. Spyker
President, Chief Executive Officer and Director

(signed) "*David W. Hendry*"
David W. Hendry
Vice President, Finance and Chief Financial 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, 2021.

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

Freehold
ROYALTIES LTD.

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