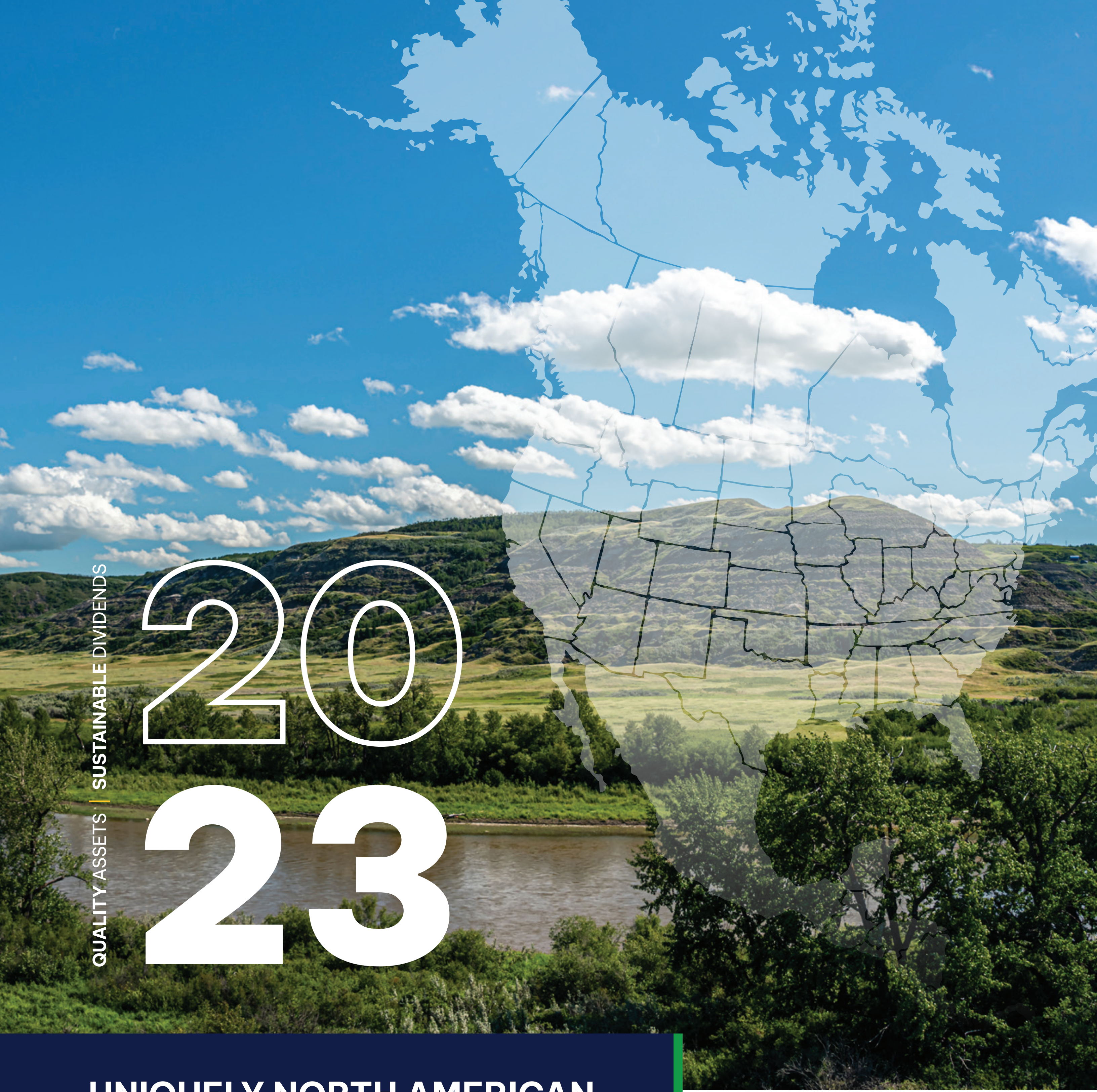

QUALITY ASSETS | SUSTAINABLE DIVIDENDS

2023

UNIQUELY NORTH AMERICAN

ANNUAL INFORMATION FORM (AIF) | TSX **FRU**

DATED | **FEBRUARY 28** | 2024

FREEHOLD ROYALTIES

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Advisories

Cautionary Statement Regarding

Forward-Looking Information and Statements

This Annual Information Form ("**AIF**"), including documents incorporated by reference, contains forward-looking information and statements (collectively "**forward-looking statements**"). These statements, which relate to future events or our future performance, are provided to allow readers to better understand our business and prospects and may not be suitable for other purposes. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as seek, anticipate, plan, continue, estimate, expect, may, will, project, predict, potential, targeting, intend, could, might, should, believe and similar expressions (including the negatives thereof). These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in the forward-looking statements included in this AIF are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements speak only as of the date of this AIF. We assume no obligation to revise or update these statements except as required pursuant to applicable securities laws.

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

- Freehold Royalties Ltd.'s ("Freehold" or the "Corporation") strategy with respect to future acquisitions and the possibility that the Board of Directors may vary the strategy in the future;
- the performance characteristics of our oil and natural gas properties;
- the estimated future value of our oil and natural gas reserves;
- projected oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices, costs and exchange and inflation rates;
- expected royalty rates and the anticipated benefits of royalty incentive programs;
- estimated abandonment and reclamation costs of working interest properties;
- expectations regarding the impact of the transition of Canadian Dollar Offered Rate (CDOR) to Canadian Overnight Repo Rate Average (CORRA) on the cost of Freehold's borrowings;
- the anticipated benefits of the acquisition of certain U.S. and Canadian royalty assets and the expectation that multiple year developments will occur on the acreage;
- the expectation that Freehold will have no future development costs associated with development of its reserves;
- expected timing for development of undeveloped reserves;
- the funding and payment of future dividends;
- estimated operating costs;
- anticipated capital expenditures and 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 anticipated acreage of unproved properties on which Freehold expects its rights to expire within the next year;
- expectations regarding additional oil or natural gas that may be recovered from certain royalty properties in which we have an interest, including potential for drilling activity by third parties on undeveloped Royalty Lands (as defined herein);
- our 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;
- Freehold's anticipated acquisition strategy and the expectation that such strategy will provide both near and long-term growth in value;
- the expectation that Freehold may acquire additional royalties and other forms of oil and natural gas related assets;
- the expectation that properties to be acquired will be operated by competent third parties;
- the expected components of the purchase price paid by Freehold for newly created royalties;
- expectations with respect to income tax payable in Canada and the United States in 2024;
- Freehold's expectations with respect to the treatment, timing and anticipated results/outcome of its proceedings with the CRA;
- expectations with respect to the timing of Freehold's Annual Meeting of Shareholders and documents relating thereto;
- expectations regarding the timing with respect to the in-service date of the Trans Mountain Pipeline, expansion of the NGTL System (as defined herein) and the introduction of new IAA framework (as defined herein); and
- expectations regarding future climate change, emission reduction and emission cap regulations, liability management regulations and regulations regarding Indigenous consultation and the resulting effects on Freehold and the industry in general.

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;
- the impact of development of alternatives to, and changing demand for, petroleum products;
- the impact of any changes in the regulatory or royalty regimes in the jurisdictions where the Corporation has assets;
- liabilities inherent in oil and natural gas operations;
- changes in general economic, market and business conditions;
- the effects of the Russian/Ukrainian conflict and Israel/Hamas conflict on commodity prices and the world economy;
- 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;
- uncertainties in regard to abandonment and reclamation liabilities and costs in oil and gas natural properties in which Freehold owns a working interest;
- operational dependence on the financial and operational capacity of royalty payors and third party operators for Freehold's revenues;
- risks related to the environment and changing environmental laws, such as, carbon tax and methane emissions regulations;
- risks pertaining to supply chain issues and inflationary pressures;
- fluctuations in the availability and cost of borrowing;
- 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;
- royalty rates;
- 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;
- the timing and amount of capital expenditures;
- future operating costs;
- 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.

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.

"**2020 Subscription Receipts**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

"**2021 Subscription Receipts**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

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

"**Acquisitions Opportunities Agreement**" means the amended and restated acquisitions opportunities agreement effective March 1, 2021 among Rife, Freehold, the Manager and Canpar, as amended and restated May 11, 2022.

"**Assessments**" has the meaning ascribed thereto under "*Legal Proceedings and Regulatory Actions*".

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

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

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

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

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

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

"**Deferred and Restricted Share Unit Plan**" means the amended and restated deferred and restricted share unit plan for non-management directors of Freehold whereby fully vested Deferred Share Units and/or Restricted 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 and Restricted Share Unit Plan.

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

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

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

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

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

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

- in relation to production and reserves, our working interest (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.

"**January 2021 U.S. Royalty Assets**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

"**January 2021 U.S. Royalty Transaction**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

"**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*.

"**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**" or "**proved**" and "**Probable**" or "**probable**" reserves have the meanings given to those terms under "*Reserves Data – Disclosure of Reserves Data*".

"**Restricted Share Units**" means our restricted share units issued pursuant to the Deferred and Restricted Share Unit Plan.

"**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.

"**Ryder Scott**" means RSC Group, Inc., independent qualified reserves evaluators of Calgary, Alberta.

"**Ryder Scott Report**" means the report dated January 25, 2024 prepared by Ryder Scott, evaluating our U.S. oil, natural gas and natural gas liquids reserves as at December 31, 2023.

"**SEDAR+**" means, prior to July 25, 2023, the System for Electronic Document Analysis and Retrieval, and as of and following July 25, 2023, the System for Electronic Data Analysis and Retrieval+, each as maintained by the Canadian Securities Administrators.

"**September 2021 Offering**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

"**September 2021 U.S. Royalty Assets**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

"**September 2021 U.S. Royalty Transaction**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

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

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

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

"**Trimble Report**" means the report dated January 29, 2024 prepared by Trimble, evaluating our Canadian oil, natural gas, natural gas liquids, and sulphur reserves as at December 31, 2023.

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

"**USA**", "**U.S.**" 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
NYMEX the New York Mercantile Exchange, a U.S. based commodity futures market
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 energy 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 energy-related assets 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, potash and other industrial 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 either oil and gas operations or other businesses analogous to the business of Freehold 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.

Under the terms of the Acquisitions Opportunities Agreement, Rife ensures that Freehold receives priority to consider acquisition opportunities for royalty interests in oil and gas properties. The Acquisitions Opportunities Agreement also sets out a framework that allows each of Freehold and Rife an opportunity to elect to participate in acquisition opportunities for royalty interests in alternative minerals (non-oil and gas) as well as non-resource income streams with the percentage of each entity's participation dependent on whether the acquisition opportunity relates to an existing property of Rife, Canpar or Freehold.

To date, the Management Fee payable to the Manager has been paid in Common Shares. Under the terms of the Management Agreement, the number of Common Shares issuable as payment of the Management Fee has been gradually reduced over the past several years. Under the terms of the Management Agreement, Freehold has the option to elect to pay the Management Fee in cash in lieu of issuing Common Share with the cash equal to the value of such Common Shares as determined by the market price of such Common Shares at the time of payment. See "*The Manager – Compensation – Management Fee*".

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 provides 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 16.66% 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.

1872348 is a corporation formed under the laws of Alberta. 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. 1872348 acts as FHT's trustee.

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.

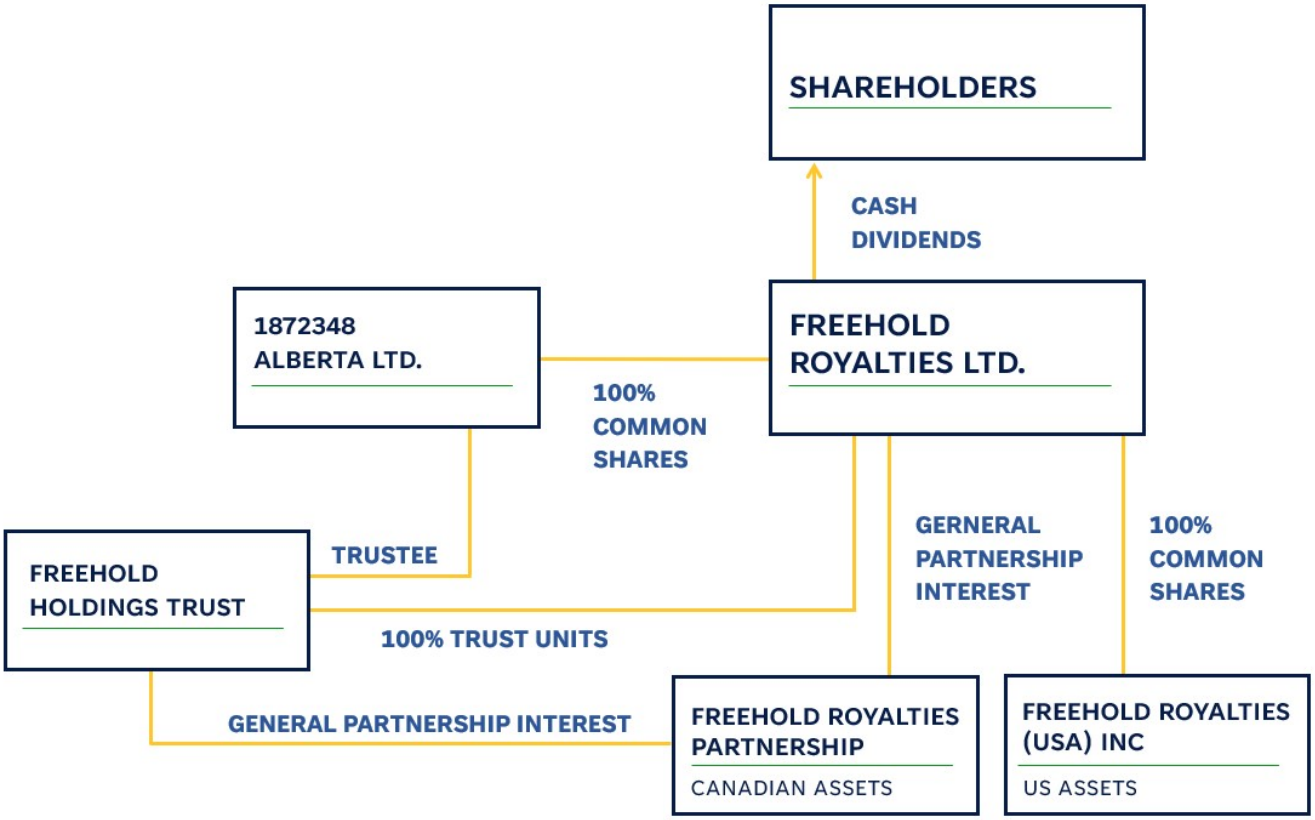
Structure of the Corporation

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, 2021.

Year Ended December 31, 2021

On January 5, 2021, Freehold closed a transaction whereby it purchased certain mineral title and royalty interest assets in the United States (the "January 2021 U.S. Royalty Assets") for an aggregate purchase price of US$58 million ($74 million) from a private seller (the "January 2021 U.S. Royalty Transaction"). On the same date, the net proceeds of a bought deal offering of 9,856,000 subscription receipts (the "2020 Subscription Receipts") of the Corporation at a price of $4.80 per 2020 Subscription Receipt for gross proceeds of approximately $47 million, which closed on December 9, 2020, were released from escrow to Freehold to partially fund the purchase price for the January 2021 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 January 2021 U.S. Royalty Transaction and in accordance with the terms of the 2020 Subscription Receipts, each 2020 Subscription Receipt was exchanged for one Common Share.

The January 2021 U.S. Royalty Transaction added exposure to approximately 400,000 gross acres to Freehold's portfolio. As a result of the January 2021 U.S. Royalty Transaction, Freehold acquired a royalty interest in approximately 1,800 producing wells. The January 2021 U.S. Royalty Assets include mineral title and royalty interests in eight states and 12 oil and natural gas basins that added 1,150 boe/d of production in 2021. The majority of the value of the January 2021 U.S. Royalty Assets is concentrated in the prolific Permian (Delaware and Midland) and Eagle Ford basins in Texas.

In July 2021, Freehold closed the acquisition of certain U.S royalty properties for US$15.9 million ($19.5 million). This acquisition included exposure to the Eagle Ford, Delaware and Midland basins in Texas, expanding Freehold's North American royalty footprint. The acquired royalty assets provide exposure to a strong suite of exploration and production companies with multiple year development plans expected on the acreage.

On September 8, 2021, Freehold entered into a definitive agreement with a private seller to acquire certain royalty interest assets in the United States (the "September 2021 U.S. Royalty Assets") for an aggregate purchase price of US$180 million ($227 million) less customary adjustments (the "September 2021 U.S. Royalty Transaction"). The September 2021 U.S. Royalty Assets consist of a concentrated royalty land position in the core of the Eagle Ford oil basin in Texas across approximately 92,000 gross acres with an average royalty rate of approximately 1.8%.

In connection with the September 2021 U.S. Royalty Transaction, on September 22, 2021, Freehold closed a bought deal offering of 16,580,000 subscription receipts ("2021 Subscription Receipts") of the Corporation at a price of $9.05 per 2021 Subscription Receipt for gross proceeds of approximately $150 million (the "September 2021 Offering"). The September 2021 U.S. Royalty Transaction closed on September 24, 2021 and the net proceeds of the September 2021 Offering were released from escrow to Freehold to partially fund the purchase price for the September 2021 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 September 2021 U.S. Royalty Transaction and in accordance with the terms of the 2021 Subscription Receipts, each 2021 Subscription Receipt was exchanged for one Common Share.

In October 2021, Freehold acquired concentrated, high quality U.S. royalty assets in Texas for US$53.3 million ($67.5 million). The acquired assets are concentrated in the Midland basin in Texas.

Freehold also closed three additional U.S. royalty transactions and one Canadian royalty transaction in 2021, further complementing our positions in the Bakken and Permian basins in the U.S. and Clearwater play in Canada. Total consideration associated with these additional U.S. transactions was approximately US$3.7 million ($4.9 million) and $5.8 million for the Canadian transaction.

Year Ended December 31, 2022

On June 28, 2022, Freehold closed a transaction to acquire mineral title and overriding royalty interests located in the core of the Midland basin in Texas across approximately 220,000 gross acres for US$15.1 million ($19.4 million), net of customary closing adjustments.

On August 4, 2022, Freehold acquired U.S. mineral title and royalty assets located in the Midland basin predominantly in Howard County, Texas (Permian Basin) across 51,000 gross acres for cash consideration of US$97.7 million ($125.7 million), net of customary closing adjustments.

On August 19, 2022, Freehold acquired U.S. mineral title and royalty assets located in the Eagle Ford basin in Texas across 41,000 gross acres for cash consideration of US$25.4 million ($32.8 million), net of customary closing adjustments.

On August 30, 2022, Freehold closed a royalty transaction prospective for Clearwater oil in Canada for up to $18.4 million. This deal includes a drilling commitment and adds greater than 300,000 gross acres to our Clearwater land position (Alberta West).

Year Ended December 31, 2023

On December 10, 2023, Freehold entered into definitive agreements with two private sellers to acquire high quality Permian mineral title and royalty assets located in the Midland basin in Texas and the Delaware basin in New Mexico and Texas for approximately US$86 million ($115 million). Both acquisitions closed in January 2024. The acquired assets included 123,000 gross acres concentrated in the core of the Permian Basin (approximately 76% in the Midland basin and 24% in the Delaware basin). It is expected that the acquired assets will contribute approximately 600 boe/d of production in 2024.

Significant Acquisitions

During the year ended December 31, 2023, Freehold did not complete any acquisitions that would be considered significant pursuant to NI 51-102.

Business of the Corporation

The following provides a description of Freehold's business and assets as at December 31, 2023 (unless otherwise indicated).

Overview

Freehold is an Alberta-based, dividend-paying corporation with a focus on royalty assets. Freehold manages one of the largest non-government portfolios of oil and natural gas royalties in Canada with an expanding land base in the United States, uniquely positioning it as a North American royalty company. Freehold's total land holdings encompass approximately 6.2 million gross acres in Canada and Freehold has exposure to approximately 900,000 gross drilling unit acres in the U.S. (approximately 1.1 million as of February 28, 2024), collectively greater than 99% of which are Royalty Lands. Freehold's Canadian mineral title lands (including royalty assumption lands), which it owns in perpetuity, cover approximately 1.1 million acres and Freehold also has gross overriding royalty and other interests in approximately 5.1 million acres. Freehold's U.S. acreage is comprised of 78% mineral title lands.

Freehold has royalty interests in almost 20,000 producing wells and almost 400 units spanning five provinces and eight states and receives Royalty Income from approximately 360 industry operators throughout North America. Freehold's revenues also include, bonus consideration, lease rental, potash and other industrial resource streams that diversify its royalty revenue portfolio. Freehold's North American land base lowers its risk, and as a royalty owner, it benefits from the drilling activity of others without any capital investments.

Royalties offer the benefit of sharing in production, without exposure to the capital, operating and environmental costs associated with production of oil, natural gas, potash and other industrial resources. As a royalty interest owner, Freehold does not pay any of the capital costs to drill and equip the wells for production on its properties, nor does it incur costs to operate the wells, maintain production, and ultimately restore the land to its original state. All of these costs are paid by others. Freehold receives Royalty Income from gross production revenue (revenue before any royalty expenses and operating costs are deducted). Freehold's royalty positions are generally considered "interests in land"; which is a benefit in that these royalties generally survive even through an insolvency event of the operator.

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 value and assets of Freehold through the acquisition of royalty interests in oil and natural gas properties and alternative minerals properties.

Freehold may, directly or indirectly through its subsidiaries and partnerships, acquire additional energy-related royalties and other forms of oil and natural gas related interests that are primarily of a low risk nature. Acquired properties 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;
- assets operated by companies with acceptable environmental, social and governance practices and stewardship; 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.

In addition to the acquisition of royalties on traditional oil and gas properties, in recent years Freehold has commenced pursuing acquisition opportunities for royalty interests (or analogous interests) in non-oil and gas resources and other energy income streams. The acquisition criteria used for non-oil and gas resources and other energy income streams is substantially the same as the criteria used for evaluating acquisition opportunities for royalties on traditional oil and gas properties.

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 production in 2023. 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 health and safety 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 periodic assessments, and audits. Environmental, health and safety exposures are tracked and addressed with short and long-term initiatives.

A detailed description of Freehold's corporate reporting initiatives and a discussion of environmental, social and governance issues are contained in Freehold's Sustainability Report, dated January 16, 2023, 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, 2023.

In accordance with the requirements of NI 51-101, the Reports on Reserves Data by Independent Qualified Reserves Evaluators 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 evaluations by our independent qualified reserves evaluators, Trimble and Ryder Scott. Both the Trimble Report and the Ryder Scott Report have an effective date of December 31, 2023. The Trimble Report has a preparation date of January 29, 2024 and the Ryder Scott has a preparation date of January 25, 2024.

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 and the Ryder Scott Report have 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 and Ryder Scott 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, 2023 were located in Canada and the United States and, specifically, in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, and Ontario in Canada and in the states of Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas and Wyoming in the United States. Trimble evaluated the Corporation's Canadian assets and Ryder Scott evaluated the Corporation's United States assets.

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 varinces 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, 2023
FORECAST PRICES AND COSTS[1,2]

CANADA

Reserves Category	Light and Medium Crude Oil Gross (Mbbls)	Light and Medium Crude Oil Net (Mbbls)	Tight Oil Gross (Mbbls)	Tight Oil Net (Mbbls)	Heavy Crude Oil Gross (Mbbls)	Heavy Crude Oil Net (Mbbls)
Proved						
Developed producing	-	3,968	-	579	-	2,137
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,708	-	189	-	483
Total proved	-	5,676	-	769	-	2,620
Probable	-	2,881	-	233	-	829
Total proved plus probable	**-**	**8,557**	**-**	**1,001**	**-**	**3,449**

Reserves Category	Conventional Natural Gas Gross (MMcf)	Conventional Natural Gas Net (MMcf)	Coal Bed Methane Gross (MMcf)	Coal Bed Methane Net (MMcf)	Shale Gas Gross (MMcf)	Shale Gas Net (MMcf)
Proved						
Developed producing	1,161	48,421	-	1,066	-	1,754
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	2,502	-	-	-	816
Total proved	1,161	50,923	-	1,066	-	2,569
Probable	256	9,269	-	136	-	724
Total proved plus probable	**1,416**	**60,192**	**-**	**1,202**	**-**	**3,294**

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	9	1,534	202	16,758
Developed non-producing	-	-	-	-
Undeveloped	-	140	-	3,073
Total proved	9	1,674	202	19,832
Probable	-	359	43	5,990
Total proved plus probable	**9**	**2,033**	**245**	**25,822**

UNITED STATES

Reserves Category	Tight Oil Gross (Mbbls)	Tight Oil Net (Mbbls)	Shale Gas Gross (MMcf)	Shale Gas Net (MMcf)	Natural Gas Liquids Gross (Mbbls)	Natural Gas Liquids Net (Mbbls)
Proved						
Developed producing	-	5,222	-	13,891	-	2,028
Developed non-producing	-		-	-	-	-
Undeveloped	-	460	-	1,398	-	203
Total proved	-	5,682	-	15,289	-	2,231
Probable	-	9,085	-	29,634	-	4,148
Total proved plus probable	**-**	**14,767**	**-**	**44,923**	**-**	**6,379**

Reserves Category	Total Oil Equivalent Gross (Mboe)	Total Oil Equivalent Net (Mboe)
Proved		
Developed producing	-	9,565
Developed non-producing	-	-
Undeveloped	-	896
Total proved	-	10,461
Probable	-	18,172
Total proved plus probable	**-**	**28,633**

TOTAL

Reserves Category	Light and Medium Crude Oil Gross (Mbbls)	Light and Medium Crude Oil Net (Mbbls)	Tight Oil Gross (Mbbls)	Tight Oil Net (Mbbls)	Heavy Crude Oil Gross (Mbbls)	Heavy Crude Oil Net (Mbbls)
Proved						
Developed producing	-	3,968	-	5,801	-	2,137
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,708	-	649	-	483
Total proved	-	5,676	-	6,451	-	2,620
Probable	-	2,881	-	9,318	-	829
Total proved plus probable	**-**	**8,557**	**-**	**15,768**	**-**	**3,449**

Reserves Category	Conventional Natural Gas Gross (MMcf)	Conventional Natural Gas Net (MMcf)	Coal Bed Methane Gross (MMcf)	Coal Bed Methane Net (MMcf)	Shale Gas Gross (MMcf)	Shale Gas Net (MMcf)
Proved						
Developed producing	1,161	48,421	-	1,066	-	15,645
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	2,502	-	-	-	2,214
Total proved	1,161	50,923	-	1,066	-	17,858
Probable	256	9,269	-	136	-	30,358
Total proved plus probable	**1,416**	**60,192**	**-**	**1,202**	**-**	**48,217**

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	9	3,562	202	26,323
Developed non-producing	-	-	-	-
Undeveloped	-	343	-	3,969
Total proved	9	3,905	202	30,293
Probable	-	4,507	43	24,162
Total proved plus probable	**9**	**8,412**	**245**	**54,455**

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

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2023 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	936,216	704,768	572,482	486,187	425,168
Developed non-producing	(5,654)	(4,213)	(3,342)	(2,765)	(2,359)
Undeveloped	248,904	194,797	159,657	134,641	116,000
Total proved	1,179,467	895,352	728,797	618,062	538,808
Probable	490,309	297,510	201,529	146,371	111,758
Total proved plus probable	**1,669,776**	**1,192,862**	**930,326**	**764,434**	**650,566**

CANADA	After Income Taxes[4], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	817,086	608,551	491,417	415,873	362,872
Developed non-producing	(4,254)	(3,171)	(2,515)	(2,081)	(1,776)
Undeveloped	185,432	145,064	119,022	100,516	86,737
Total proved	998,264	750,444	607,924	514,308	447,833
Probable	365,268	221,589	150,157	109,136	83,403
Total proved plus probable	**1,363,532**	**972,034**	**758,081**	**623,444**	**531,236**

UNITED STATES	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	701,678	445,719	333,760	272,199	233,132
Developed non-producing	-	-	-	-	-
Undeveloped	58,430	42,981	35,439	30,947	27,906
Total proved	760,108	488,700	369,199	303,146	261,038
Probable	1,373,178	724,809	469,248	337,095	257,336
Total proved plus probable	**2,133,286**	**1,213,509**	**838,447**	**640,241**	**518,374**

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	636,603	409,568	309,053	253,306	217,714
Developed non-producing	-	-	-	-	-
Undeveloped	45,555	34,354	28,774	25,396	23,077
Total proved	682,158	443,922	337,827	278,702	240,791
Probable	1,072,783	559,576	357,699	253,494	190,750
Total proved plus probable	**1,754,941**	**1,003,498**	**695,526**	**532,196**	**431,540**

TOTAL	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	1,637,894	1,150,487	906,242	758,386	658,300
Developed non-producing	(5,654)	(4,213)	(3,342)	(2,765)	(2,359)
Undeveloped	307,334	237,778	195,096	165,588	143,906
Total proved	1,939,575	1,384,052	1,097,996	921,208	799,846
Probable	1,863,487	1,022,319	670,777	483,466	369,094
Total proved plus probable	**3,803,062**	**2,406,371**	**1,768,773**	**1,404,675**	**1,168,940**

TOTAL	After Income Taxes[4], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	1,453,689	1,018,119	800,470	669,179	580,586
Developed non-producing	(4,254)	(3,171)	(2,515)	(2,081)	(1,776)
Undeveloped	230,987	179,418	147,796	125,912	109,814
Total proved	1,680,422	1,194,366	945,751	793,010	688,624
Probable	1,438,051	781,165	507,856	362,630	274,153
Total proved plus probable	**3,118,473**	**1,975,532**	**1,453,607**	**1,155,640**	**962,776**

1. Columns may not add due to rounding.
2. Estimates of future net revenue reflect a deduction for estimated operating costs.
3. For the purposes of the Trimble Report on Freehold's Canadian working interest assets, estimates of future net revenue reflect a deduction for estimated 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. As Freehold only holds royalty interests in the United States and no working interests, for the purposes of the Ryder Scott Report on Freehold's United States assets, no deduction has been made for abandonment, decommissioning and reclamation costs as the Corporation has no liability for such costs on its royalty interest properties. No volumes have been attributed to Canadian working interest proved developed non-producing wells but there is associated inactive abandonment and reclamation costs, as such the future net revenue for such proved developed non-producing wells reflects negative revenues.
4. Based on the inclusion of $459,200,000 of tax pools for Canada $426,900,000 of tax pools for the United States. See "*Other Oil and Gas Information – Tax Horizon*".

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2023 FORECAST PRICES AND COSTS[1]

	Proved Reserves		
($000s)	Canada	United States	Total
Royalty Income	1,200,749	845,934	2,046,683
Revenue from working interest properties	5,994	-	5,994
Royalty expense	(444)	-	(444)
Production and ad valorum taxes	-	(57,012)[3]	(57,012)
Operating costs	(22,847)	(28,814)[4]	(51,661)
Development costs	-	-	-
Abandonment and reclamation costs[2]	(3,985)	-	(3,985)
Future net revenue before income taxes	1,179,467	760,108	1,939,575
Future income taxes	(181,202)	(77,950)	(259,152)
Future net revenue after income taxes	**998,264**	**682,158**	**1,680,422**

	Proved Plus Probable Reserves		
($000s)	Canada	United States	Total
Royalty Income	1,694,182	2,379,602	4,073,784
Revenue from working interest properties	7,622	-	7,622
Royalty expense	(590)	-	(590)
Production and ad valorum taxes	-	(166,865)[3]	(166,865)
Operating costs	(27,407)	(79,451)[4]	(106,858)
Development costs	-	-	-
Abandonment and reclamation costs[2]	(4,031)	-	(4,031)
Future net revenue before income taxes	1,669,776	2,133,286	3,803,062
Future income taxes	(306,243)	(378,345)	(684,588)
Future net revenue after income taxes	**1,363,532**	**1,754,941**	**3,118,473**

1. Columns may not add due to rounding.
2. For the purposes of the Trimble Report on Freehold's Canadian working interest assets, estimates of future net revenue reflect a deduction for estimated 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. As Freehold only holds royalty interests in the United States and no working interests, for the purposes of the Ryder Scott Report on Freehold's United States assets, no deduction has been made for abandonment, decommissioning and reclamation costs as the Corporation has no liability for such costs on its royalty interest properties.
3. Represents both severance and ad valorem taxes, which are taxes imposed on the removal of natural resources within a taxing jurisdiction. The applicable severance tax is specific to the law of the State in which operations take place. The severance tax is levied at a percentage of market value of the hydrocarbon product or at a unit value of the hydrocarbon product. The applicable ad valorem tax is specific to the law of the County in which operations take place. The ad valorem tax is levied as a percentage of market value of the hydrocarbon product.
4. Represents processing fees which are those post production fees payable by the owner of the hydrocarbon reserves to make the hydrocarbon product marketable. Royalty owners are responsible for their applicable fees.

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2023
FORECAST PRICES AND COSTS[1,2]

CANADA

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	$/boe	$/Mcfe
		($000s)		
Proved	Light and Medium Crude Oil (including solution gas and by-products)	398,186	56.97	9.49
	Tight Oil (including solution gas and other by-products)	51,157	53.54	8.92
	Heavy Crude Oil (including solution gas and other by-products)	142,311	50.65	8.44
	Conventional Natural Gas (including by-products)	132,117	15.69	2.61
	Coal Bed Methane (including by-products)	2,199	12.36	2.06
	Shale Gas (including by-products)	6,168	12.96	2.16
	Total Proved	**732,139**	**36.92**	**6.15**
Proved plus probable	Light and Medium Crude Oil (including solution gas and by-products)	542,719	51.54	8.59
	Tight Oil (including solution gas and other by-products)	62,244	49.57	8.26
	Heavy Crude Oil (including solution gas and other by-products)	176,397	48.01	8.00
	Conventional Natural Gas (including by-products)	142,770	14.94	2.49
	Coal Bed Methane (including by-products)	2,404	11.98	2.00
	Shale Gas (including by-products)	7,135	11.78	1.96
	Total Proved Plus Probable	**933,668**	**36.16**	**6.03**

UNITED STATES

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	$/boe	$/Mcfe
		($000s)		
Proved	Tight Oil (including solution gas and other by-products)	363,587	36.10	6.02
	Shale Gas (including by-products)	5,612	14.50	2.42
	Total Proved	**369,199**	**35.30**	**5.88**
Proved plus probable	Tight Oil (including solution gas and other by-products)	820,890	30.09	5.02
	Shale Gas (including by-products)	17,557	12.97	2.16
	Total Proved Plus Probable	**838,447**	**29.28**	**4.88**

TOTAL

Reserves Category	Well Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	$/boe	$/Mcfe
		($000s)		
Proved	Light and Medium Crude Oil (including solution gas and by-products)	398,186	56.97	9.49
	Tight Oil (including solution gas and other by-products)	414,744	37.61	6.27
	Heavy Crude Oil (including solution gas and other by-products)	142,311	50.65	8.44
	Conventional Natural Gas (including by-products)	132,117	15.69	2.61
	Coal Bed Methane (including by-products)	2,199	12.36	2.06
	Shale Gas (including by-products)	11,780	13.65	2.28
	Total Proved	**1,101,338**	**36.36**	**6.06**
Proved plus probable	Light and Medium Crude Oil (including solution gas and by-products)	542,719	51.54	8.59
	Tight Oil (including solution gas and other by-products)	883,134	30.95	5.16
	Heavy Crude Oil (including solution gas and other by-products)	176,397	48.01	8.00
	Conventional Natural Gas (including by-products)	142,770	14.94	2.49
	Coal Bed Methane (including by-products)	2,404	11.98	2.00
	Shale Gas (including by-products)	24,692	12.60	2.10
	Total Proved Plus Probable	**1,772,115**	**32.54**	**5.42**

1. Columns may not add due to rounding.
2. For the purposes of calculating future net revenue by product type in the Trimble Report, operating cost expense, plus abandonment, decommissioning and reclamation capital costs totalling $3,342,000 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 Freehold only holds royalty interests in the United States and no working interests, for the purposes of the Ryder Scott Report on Freehold's United States assets, no deduction has been made for abandonment, decommissioning and reclamation costs as the Corporation has no liability for such costs on its royalty interest properties. 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 and the Ryder Scott 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 excluding sulphur 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 ("**Proved**" or "**proved**") 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 ("**Probable**" or "**probable**") 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, 2023 utilized in the Trimble Report and Ryder Scott Report were based on the average of the forecasts prepared by GLJ Ltd., McDaniel & Associates Ltd. and Sproule Associates Limited effective as at January 1, 2024, which are as follows:

FORECAST PRICES USED IN ESTIMATES
AS OF DECEMBER 31, 2023

	Oil					Natural Gas		Canadian Natural Gas Liquids		
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
2024	73.67	92.91	69.01	77.44	76.74	2.20	2.75	29.65	47.69	96.79
2025	74.98	95.04	71.90	80.48	79.77	3.37	3.64	35.13	48.83	98.75
2026	76.14	96.07	72.78	81.84	81.12	4.05	4.02	35.43	49.36	100.71
2027	77.66	97.99	74.41	83.61	82.88	4.13	4.10	36.14	50.35	102.72
2028	79.22	99.95	76.56	85.78	85.04	4.21	4.18	36.86	51.35	104.78
2029	80.80	101.94	78.10	87.49	86.74	4.30	4.27	37.60	52.38	106.87
2030	82.42	103.98	79.67	89.24	88.47	4.38	4.35	38.35	53.43	109.01
2031	84.06	106.06	81.27	91.01	90.24	4.47	4.44	39.12	54.50	111.19
2032	85.74	108.18	82.90	92.83	92.04	4.56	4.53	39.90	55.58	113.41
2033	87.46	110.35	84.57	94.69	93.89	4.65	4.62	40.70	56.70	115.67
Thereafter, per year:										
	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%

	U.S. Natural Gas Liquids (Mont Belvieu)			Inflation Rate	Exchange Rate
Year	Propane $US/ bbl	Butane[1] $US/ bbl	Condensate $US/ bbl	%/ Year	$US/$ Cdn
2024	31.52	40.75	62.35	0.00	0.75
2025	35.10	43.38	68.25	2.00	0.75
2026	39.04	44.02	70.06	2.00	0.76
2027	39.82	44.90	71.46	2.00	0.76
2028	40.62	45.80	72.89	2.00	0.76
2029	41.43	46.72	74.35	2.00	0.76
2030	42.26	47.65	75.84	2.00	0.76
2031	43.10	48.60	77.35	2.00	0.76
2032	43.97	49.58	78.90	2.00	0.76
2033	44.85	50.57	80.48	2.00	0.76
Thereafter, per year:					
	+2.0%	+2.0%	+2.0%	2.00	0.76

1. Butane prices represent a blended price of two-thirds normal butane and one-third iso-butane.

The following table provides the historical weighted average prices realized by Freehold for the year ended December 31, 2023:

FREEHOLD WEIGHTED AVERAGE PRICES
YEAR ENDED DECEMBER 31, 2023

	Light, Medium & Heavy Crude Oil ($/bbl)	Tight Oil ($bbl)	Natural Gas ($/Mcf)	Shale Gas ($/Mcf)	Natural Gas Liquids ($/bbl)	Oil Equivalent ($/boe)
Canada						
Freehold weighted average price	87.48 [1]	-	2.32 [2]	-	51.47	50.82
United States						
Freehold weighted average price	-	104.56	-	2.75	27.96	70.50

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.

"**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 and all of Freehold's reserves as estimated in the Ryder Scott 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 and Ryder Scott 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 and Ryder Scott were accepted by Trimble and Ryder Scott 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. In addition, Freehold has only presented a gross reserves reconciliation for conventional natural gas and natural gas liquids as those are the only product types in which Freehold holds a working interest.

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS[1]

CANADA	Conventional Natural Gas			Natural Gas Liquids			Total Oil Equivalent		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2022	841	212	1,053	11	2	13	151	37	188
Production	(196)	-	(196)	(2)	-	(2)	(35)	-	(35)
Technical revisions	500	43	542	(1)	(2)	(3)	82	5	87
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	16	1	17	1	-	1	4	-	4
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2023	**1,161**	**256**	**1,416**	**9**	**-**	**9**	**202**	**43**	**245**

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]

CANADA	Light and Medium Crude Oil			Tight Oil			Heavy Crude Oil		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2022	4,681	4,061	8,741	808	306	1,114	2,643	759	3,402
Production	(939)	-	(939)	(119)	-	(119)	(497)	-	(497)
Technical revisions	1,507	(1,649)	(142)	72	(76)	(4)	152	(181)	(28)
Extensions and improved recovery	428	469	897	8	2	10	321	250	571
Acquisitions[2]	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2023	**5,676**	**2,881**	**8,557**	**769**	**233**	**1,001**	**2,620**	**829**	**3,449**

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, 2022	49,421	12,754	62,175	1,210	223	1,433	2,386	831	3,218
Production	(8,806)	-	(8,806)	(151)	-	(151)	(299)	-	(299)
Technical revisions	7,969	(4,849)	3,120	7	(87)	(80)	482	(107)	375
Extensions and improved recovery	2,312	1,357	3,669	-	-	-	-	-	-
Acquisitions[2]	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	27	7	33	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2023	**50,923**	**9,269**	**60,192**	**1,066**	**136**	**1,202**	**2,569**	**724**	**3,294**

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, 2022	1,402	452	1,854	18,370	7,879	26,249
Production	(317)	-	(317)	(3,414)	-	(3,414)
Technical revisions	510	(142)	368	3,650	(2,887)	763
Extensions and improved recovery	78	49	127	1,221	997	2,218
Acquisitions[2]	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	1	-	1	5	1	6
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2023	**1,674**	**359**	**2,033**	**19,832**	**5,990**	**25,822**

UNITED STATES	Tight Oil			Shale Gas			Natural Gas Liquids		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2022	5,658	10,044	15,701	15,583	25,484	41,067	2,233	3,490	5,723
Production	(1,035)	(23)	(1,058)	(2,274)	(52)	(2,326)	(320)	(7)	(328)
Technical revisions	267	(1,068)	(801)	149	1,806	1,955	29	466	495
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions[2]	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	(1)	(3)	(4)	(75)	(31)	(106)	(3)	(2)	(5)
Infill drilling	794	135	929	1,905	2,427	4,332	291	202	493
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2023	**5,682**	**9,085**	**14,767**	**15,289**	**29,634**	**44,923**	**2,231**	**4,148**	**6,379**

UNITED STATES	Total Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2022	10,488	17,781	28,269
Production	(1,735)	(39)	(1,774)
Technical revisions	321	(301)	20
Extensions and improved recovery	-	-	-
Acquisitions[2]	-	-	-
Dispositions	-	-	-
Economic factors	(16)	(10)	(26)
Infill drilling	1,403	741	2,144
Discoveries	-	-	-
December 31, 2023	**10,461**	**18,173**	**28,633**

TOTAL	Light and Medium Crude Oil			Tight Oil			Heavy Crude Oil		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2022	4,681	4,061	8,741	6,466	10,350	16,815	2,643	759	3,402
Production	(939)	-	(939)	(1,154)	(23)	(1,177)	(497)	-	(497)
Technical revisions	1,507	(1,649)	(142)	339	(1,144)	(805)	152	(181)	(28)
Extensions and improved recovery	428	469	897	8	2	10	321	250	571
Acquisitions[2]	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	(1)	(3)	(4)	-	-	-
Infill drilling	-	-	-	794	135	929	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2023	**5,676**	**2,881**	**8,557**	**6,451**	**9,318**	**15,768**	**2,620**	**829**	**3,449**

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, 2022	49,421	12,754	62,175	1,210	223	1,433	17,969	26,315	44,285
Production	(8,806)	-	(8,806)	(151)	-	(151)	(2,573)	(52)	(2,625)
Technical revisions	7,969	(4,849)	3,120	7	(87)	(80)	631	1,699	2,330
Extensions and improved recovery	2,312	1,357	3,669	-	-	-	-	-	-
Acquisitions[2]	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	27	7	33	-	-	-	(75)	(31)	(106)
Infill drilling	-	-	-	-	-	-	1,905	2,427	4,332
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2023	**50,923**	**9,269**	**60,192**	**1,066**	**136**	**1,202**	**17,858**	**30,358**	**48,217**

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, 2022	3,635	3,942	7,577	28,858	25,660	54,518
Production	(637)	(7)	(645)	(5,149)	(39)	(5,188)
Technical revisions	539	324	863	3,971	(3,188)	783
Extensions and improved recovery	78	49	127	1,221	997	2,218
Acquisitions[2]	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	(2)	(2)	(4)	(11)	(9)	(20)
Infill drilling	291	202	493	1,403	741	2,144
Discoveries	-	-	-	-	-	-
December 31, 2023	**3,905**	**4,507**	**8,412**	**30,293**	**24,163**	**54,455**

1. Columns may not add due to rounding.
2. In 2023, Freehold completed a number of acquisitions in the United States and a smaller acquisition of undeveloped land in Canada. For more information about these acquisitions see "*General Development of the Business*".
3. Material reserve changes for the Canadian assets relate to technical revisions, drilling extensions and improved recovery. Technical revisions relate to improved performance and probable reserves shifting to proved reserves as the assets mature. Drilling extensions relate to new wells drilled on Royalty Lands in 2023. Improved recovery relates to supplemental undeveloped locations added to the evaluation effective December 31, 2023.
4. Material reserve changes for the US assets relate to technical revisions and infill drilling. Technical revisions relate to production forecast revisions for proved developed producing wells, proved undeveloped conversions to proved developed producing, and net revenue revisions. Infill drilling relates to conversions into proved developed producing or drilled uncompleted wells from proved undeveloped locations as well as the addition of new proved undeveloped locations.

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards in the COGE Handbook. At December 31, 2023, the aggregate proved net undeveloped reserves assigned in the Trimble Report and Ryder Scott Report represented 13% of the aggregate proved net reserves assigned in such reports. At December 31, 2023, the aggregate probable net undeveloped reserves assigned in the Trimble Report and Ryder Scott Report represented 35% of the aggregate probable net reserves assigned in such reports. The following provides an explanation of how both Trimble and Ryder Scott attributed proved undeveloped reserves and probable undeveloped reserves in their respective reports and the expectations as to the development of such undeveloped reserves.

In respect of Freehold's Canadian assets, proved net undeveloped reserves represented 15% of the total proved net reserves assigned in the Trimble Report. The proved undeveloped reserves in the Trimble Report relate to locations that are within actively developed resource plays and adjacent to existing production. In the Trimble Report, approximately half of the proved undeveloped reserves are forecast to be drilled in the next two years with the remainder forecast to be drilled in the next four years. All expected drilling beyond the two year time frame is associated with resource plays and such proved undeveloped reserves have been validated based on geology and proximity to production; however, the development of such reserves has 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 one-third of the proved undeveloped reserves in the Trimble Report, future development is forecasted at an average of 58 locations per year based on recent historical drilling results.

In respect of Freehold's United States assets, proved net undeveloped reserves assigned represented 9% of the total proved net reserves assigned in the Ryder Scott Report. The proved undeveloped reserves in the Ryder Scott Report relate to drilled uncompleted wells. All of the proved undeveloped reserves in the Ryder Scott Report are expected to be developed in the next two years.

Probable net undeveloped reserves assigned in the Trimble Report represented 13% of the total proved plus probable net reserves assigned to Freehold's Canadian assets. Similar to the proved undeveloped reserves in the Trimble Report, the probable undeveloped reserves in the Trimble Report relate to locations that are within actively developed resource plays and in close proximity to existing production (although in most cases farther away from existing production than the locations associated with proved undeveloped reserves). The majority of these reserves are in resource plays where reserves are estimated from analog type curve analysis. In the Trimble Report, approximately one-quarter of the probable undeveloped are forecast to be drilled in the next two years. The balance of the probable undeveloped reserves in the Trimble Report are forecast to be drilled within ten years and have been validated based on geology and proximity to production but are deferred to correlate with the historical development drilling timeframes in individual areas. For example, in the Dodsland Viking resource play which represents approximately 35% of probable undeveloped reserves booked in the Trimble Report, future development is forecasted at an average of 58 locations per year for 5 years to match recent historical drilling results, then an average of 37 locations per year from 2029 to 2033.

Probable net undeveloped reserves assigned in the Ryder Scott Report represented 54% of the total proved plus probable net reserves assigned to Freehold's United States assets. Similarly to the probable undeveloped reserves booked in the Trimble Report, the probable undeveloped reserves in the Ryder Scott Report relate to locations that are within actively developed resource plays and in close proximity to existing production. The majority of these reserves are in resource plays where reserves are estimated from analog type curve analysis. In the Ryder Scott Report, all of the probable undeveloped reserves are forecast to be drilled between 2024 and 2032, with 16% forecast to be drilled in 2024 and 2025. The balance of the probable undeveloped reserves in the Ryder Scott

Report, which are forecast to be drilled between 2026 and 2032, have been validated based on geology and proximity to production but are deferred to correlate with the historical development drilling timeframes in individual areas.

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 development of undeveloped reserves will be dependent on a number of factors including commodity pricing and the availability of capital for our royalty payors to develop 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, 2023, 2022, and 2021, 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)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Natural Gas Liquids (Mbbls)
2021	-	433	118	155	1,039	141
2022	3	623	-	15	1,719	283
2023	146	354	208	237	1,059	163
Total Booked for Current Year	**1,708**	**649**	**483**	**2,502**	**2,21**	**343**

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

Year	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Natural Gas Liquids (Mbbls)
2021	-	7,524	120	103	19,144	1,968
2022	75	3,413	-	137	8,463	1,440
2023	383	925	215	461	4314	508
Total Booked for Current Year	**2,155**	**8,118**	**452**	**2,538**	**27,736**	**3,918**

Significant Factors or Uncertainties

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

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 and Ryder Scott, independent qualified reserves evaluators. Trimble and Ryder Scott consider 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 drilling and resources recovery 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 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

The following provides a description of Freehold's business assets as at December 31, 2023 (unless otherwise indicated).

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 in Canada (approximately 6.2 million gross acres) and the states of Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas and Wyoming in the United States (exposure to approximately 900,000 gross acres and approximately 1,100,000 gross acres as of February 28, 2024).

Producing lands include Crown, freehold, unitized and non-unitized oil and natural gas, potash and other industrial resources production. The properties are operated by experienced operators. Our top ten active drillers through year-end 2023 were in alphabetic order: Bonterra Energy Corp. ConocoPhillips, Endeavor Energy Resources, LP, EOG Resources Inc., HighPeak Energy, Marathon Oil Corporation, Pioneer Natural Resources Co., Rubellite Energy Inc., Surge Operating and Teine Energy Ltd.

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, which allows Freehold to take ownership of a percentage of the oil and natural gas produced rather than receiving a financial royalty payment. 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, 2023, we take in-kind and market approximately 3% 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 own 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 2023, this category of land provided approximately 37% of our overall (Canada and US) royalty production.

In Canada, we have ownership interests in mineral titles generally ranging from 10% to 100% and recover the applicable royalty, generally 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 and/or natural gas produced for the period. In 2023, this category of land accounted for approximately 16% of our total royalty acreage in Canada.

Our mineral title lands encompass approximately 1,033,000 acres, of which 45% are leased and 55% are unleased. The mineral title lands also include approximately 688,000 undeveloped acres, representing potential for future development.

In the United States we have ownership interests in mineral titles and recover our applicable portion of the gross royalty, generally ranging from 12.5% to 25%, of all oil and gas produced from the leased lands, netted down by our interest in the drilling spacing unit. In 2023, this category of land accounted for approximately 78% of our total royalty acreage in the United States.

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 lands, of which approximately 19,300 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 2023, this category of land accounted for approximately 1% of our total royalty acreage and provided approximately 1% of our royalty production.

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

Gross Overriding Royalty Lands

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 2023, this category of land provided approximately 56% of our royalty production.

In Canada, we hold GORRs in approximately 5 million acres, of which approximately 1.6 million acres are undeveloped. In 2023, this category of land accounted for approximately 82% of our total royalty acreage in Canada.

In the USA, we hold GORRs across approximately 205,000 drilling unit acres, of which the majority are developed. These lands consist of properties leased by a number of third party oil and gas companies in respect of which contractual royalties have been reserved to Freehold. In 2023, this category of land accounted for approximately 22% of our total royalty acreage in the United States.

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.

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 2023, this category of royalty interests provided approximately 6% of our royalty production.

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, 2023, wells drilled, oil and natural gas production, and royalty interest for 2023 for our Royalty Lands:

Year ended December 31, 2023		Alberta West	Saskatchewan East	Eagle Ford (U.S.)	Permian (U.S.)	North Dakota & Other (U.S.)	Total
Average royalty interest [1,2]	(%)	2.1%	2.2%	1.0%	0.3%	0.4%	1.7%
Wells drilled	(gross)	280	186	153	283	91	993
Royalty interest revenue[3]	($000s)	93,844	84,469	68,344	53,046	9,893	309,596
Average net daily production	(boe/d)	6,761	2,851	2,674	1,817	611	14,714
	(% of total)	47%	19%	18%	12%	4%	100%
Oil and NGL	(bbls/d)	2,703	2,537	2,132	1,519	295	9,186
	(% of total)	29%	28%	23%	17%	3%	100%
Natural gas	(Mcf/d)	24,346	1,883	3,251	1,791	1,896	33,167
	(% of total)	73%	6%	10%	5%	6%	100%
Net proved reserves	(Mboe)	14,302	5,530	5,353	3,986	1,121	30,292
Oil and NGL	(Mbbls)	5,887	4,852	4,239	3,132	542	18,652
	(% of total)	32%	26%	23%	17%	3%	100%
Natural gas	(MMcf)	50,487	4,071	6,684	5,125	3,479	69,846
	(% of total)	72%	6%	10%	7%	5%	100%
Net proved plus probable reserves	(Mboe)	17,375	8,446	15,531	10,678	2,425	54,456
Oil and NGL	(Mbbls)	7,571	7,469	11,995	8,354	797	36,186
	(% of total)	21%	21%	33%	23%	2%	100%
Natural gas	(MMcf)	58,823	5,865	21,215	13,940	9,768	109,610
	(% of total)	54%	5%	19%	13%	9%	100%
Future Net Revenue Before Income Taxes[12]							
Discounted at 10% per year	($000s)	483,703	446,624	448,997	336,663	52,787	1,768,773
	(% of total)	27%	25%	25%	19%	3%	100%

1. Based on proved plus probable reserves and forecast prices as assigned in the Trimble Report and the Ryder Scott Report.
2. Total average royalty interest calculated as weighted average of well count under each area.
3. Excludes revenue from potash, interest and other.

The following table summarizes, by region, the gross royalty acreage with respect to our Royalty Lands, as at December 31, 2023**:**

Area	Developed Gross Acres	Undeveloped Gross Acres[1]	Total Gross Acres
Alberta West	3,157,074	1,700,374	4,857,448
Saskatchewan East	676,909	603,713	1,280,622
Eagle Ford (U.S.)	11,741	1,694	13,435
Permian (U.S.)	7,136	47	7,183
North Dakota & Other (U.S.)	11,741	1,694	13,435
Potash	12,209	7,704	19,913
Total	**3,876,810**	**2,315,226**	**6,192,036**

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

Alberta West

In 2023, 280 wells, representing 60% of our gross royalty drilling in Canada, occurred in the Alberta West area, which includes our Royalty Lands in B.C. and Alberta. These wells primarily targeted established oil and liquids rich gas plays of the Cardium, Mannville and Spirit River group, as well as continued development and exploratory drilling in the Clearwater play. In this area, 99% of the wells are horizontal drills and approximately 85% of the wells targeted oil, while the other 15% of activity was concentrated in the highly prolific Deep Basin liquids rich gas area. Cardium drilling resulted in 89 gross wells, or 32% of gross wells drilled in the area. Mannville oil and gas targets, including Sparky multi-lateral wells, resulted in 55 gross wells, or 20% of gross wells drilled in Alberta West. Clearwater activity on our lands was strong with 62 gross wells drilled during the year, representing 22% of Alberta West drilling.

Saskatchewan East

In 2023, 186 gross wells, or 40% of Freehold's gross royalty drilling in Canada 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, 98% of the wells drilled in 2023 were horizontal drills targeting oil plays.

In 2023, 39% 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 a core, stable production area 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 92 locations or 49% of the gross royalty drilling in Saskatchewan East in 2023. Freehold continues to see the benefit of well capitalized and active operators pursuing high netback opportunities in this area.

Eagle Ford (U.S. – Texas)

Freehold's Eagle Ford assets represent a core area within our U.S. portfolio. In 2023, 153 gross wells were drilled on our Royalty Lands in this area, underpinned by well capitalized investment grade producers committed to developing their assets in the area.

Permian (U.S. – Texas and New Mexico)

Freehold's Permian assets represent one of the most active areas within our portfolio. Drilling activity in 2023 resulted in 283 gross wells drilled on our Royalty Lands from a diverse group of public and private producers, many of which are focused exclusively in the Permian.

North Dakota and Other (U.S.)

The primary plays or basins of value are Bakken and Three Forks in North Dakota, Haynesville in Louisiana and Texas and Marcellus in Pennsylvania, with development occurring exclusively through horizontal drilling with well capitalized operators. In 2023, Freehold saw 91 wells drilled on its Royalty Lands across these areas.

Potash

Our potash acreage inventory is approximately 19,900 gross acres in 2023. This consists of leases we have issued on our mineral title to the various operators of nine 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 2023, we received approximately $1.6 million in royalty revenue from the production of approximately seven 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 2.3 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, 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]	**2023**	**2022**
Royalty Interest Properties (gross wells)		
Oil wells	967	999
Natural gas wells	15	51
Service/other wells	9	7
Dry and abandoned wells	2	-
Total	**993**	**1,057**
Success rate	**99.8%**	**100%**

1. Includes all drilling on properties acquired during the year from the effective date.

In addition to our royalty interests, we own an immaterial amount of working interest properties in Canada. Our working interest assets in Canada represent less than 1.0% of our total proved plus probable reserves as at December 31, 2023 and less than 1.0% of our total production in 2023.

Other Oil and Gas Information

Oil and Natural Gas Wells

The following table sets forth, by province and state, the number of producing wells in which we have a royalty interest as at December 31, 2023. These producing well counts include wells associated with our ownership in 395 units, which would account for approximately 22,600 wells.

Royalty Interest Properties	Natural Gas Wells	Oil Wells
Canada		
Alberta	14,155	9,121
Saskatchewan	672	10,088
British Columbia	97	17
Manitoba	-	1,154
Ontario	235	-
Canada Total	**15,160**	**20,379**

Royalty Interest Properties	Natural Gas Wells	Oil Wells
United States		
Colorado	154	94
Louisiana	3	-
New Mexico	-	20
North Dakota	-	422
Oklahoma	6	64
Pennsylvania	6	-
Texas	681	4815
Wyoming	28	8
United States Total	**878**	**5,423**
Total	**16,038**	**25,802**

The following table sets forth, by province, the number and status of wells in which we have a working interest as at December 31, 2023:

	Natural Gas Wells			
	Producing		Non-Producing[3]	
Working Interest Properties	Gross	Net	Gross	Net
Alberta	25	14.4	61	24.8
Saskatchewan	-	-	2	0.9
British Columbia	1	0.1	-	-
Manitoba	-	-	-	-
Ontario	-	-	-	-
Total[1,2]	**26**	**14.5**	**63**	**25.7**

1. Columns may not add due to rounding.
2. Freehold does not hold any working interests in any oil wells or any wells outside of Canada.
3. Non-producing wells listed in the table above include all working interest wells that are not currently producing but which are considered capable of producing further volumes of oil or natural gas. In addition to the wells listed in the table, Freehold has a working interest in 151 gross (41.9 net) oil wells, 32 gross (16.9 net) natural gas wells and 9 gross (3.9 net) other wells in Canada that are inactive and are not considered capable of producing any further volumes of oil or natural gas. Some of these wells have been abandoned but not reclaimed and other wells are awaiting to be abandoned.

Properties with No Attributable Reserves

The following table sets forth, by province and state, our undeveloped land holdings as at December 31, 2023:

	Undeveloped Acres		
	Royalty Lands	Working Interest Lands	
	Gross	Gross	Net
Canada			
Alberta	1,668,173	6,410	2,025
Saskatchewan	581,086	596	396
British Columbia	32,202	1,359	61
Manitoba	28,441	0	0
Ontario	1,890	0	0
Canada Total	**2,311,791**	**8,365**	**2,482**
United States			
Colorado	0	0	0
Louisiana	0	0	0
New Mexico	0	0	0
North Dakota	0	0	0
Oklahoma	25	0	0
Pennsylvania	9	0	0
Texas	2,073	0	0
Wyoming	0	0	0
United States Total	2,107	0	0
Total	**2,313,898**	**8,365**	**2,482**

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 150,000 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

Freehold was cash taxable in Canada and the USA in 2023 and expects to pay taxes in Canada and the USA in 2024.

The 2023 corporate income tax rate for Freehold was approximately 23% (2022 – 23%) and the expected corporate income tax rate for 2024 and future years is approximately 23%.

At December 31, 2023, Freehold's tax pools were $887 million (additional information is provided in Freehold's management's discussion and analysis for the year ended December 31, 2023 which is available on SEDAR+ at www.sedarplus.ca).

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.

The following table summarizes capital expenditures in Canada to acquire Royalty Lands as at December 31, 2023:

Canada	($000s)
Property acquisition costs[1]	
Proved properties	$5,187
Undeveloped/unproved properties	-
Development costs	-
Total [2]	**$5,187**

1. As classified at the time of the acquisition.
2. We did not incur any exploration costs in 2023.

The following table summarizes capital expenditures in the United States to acquire Royalty Lands as at December 31, 2023:

United States	**($000s)**
Property acquisition costs[1]	
Proved properties	$-
Undeveloped/unproved properties	-
Development costs	-
Total [2]	**$-**

1. As classified at the time of the acquisition.
2. We did not incur any exploration costs in 2023.

Production Estimates

The following tables set out the volume of gross and net production estimated for the year ended December 31, 2024 in the Trimble Report and the Ryder Scott Report, based on the forecast price case reflected in the estimate of future net revenue disclosed in the tables contained under "*Reserves Data*". No field accounts for more than 20% of the production estimate.

CANADA

	Light and Medium Crude Oil		**Tight Oil**		**Heavy Crude Oil**	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)
Proved						
Developed producing	-	2,036	-	267	-	1,089
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	344	-	45	-	178
Total proved	-	2,379	-	313	-	1,267
Probable	-	153	-	10	-	68
Total proved plus probable[1]	**-**	**2,533**	**-**	**323**	**-**	**1,335**

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	358	19,021	-	373	-	715
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	571	-	-	-	466
Total proved	358	19,592	-	373	-	1,181
Probable	4	697	-	3	-	37
Total proved plus probable[1]	**362**	**20,289**	**-**	**376**	**-**	**1,218**

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	4	664	64	7,408
Developed non-producing	-	-	-	-
Undeveloped	-	31	-	771
Total proved	4	695	64	8,179
Probable	-	30	1	384
Total proved plus probable[1]	**4**	**725**	**65**	**8,563**

UNITED STATES

Reserves Category	Tight Oil Gross (bbls/d)	Tight Oil Net (bbls/d)	Shale Gas Gross (Mcf/d)	Shale Gas Net (Mcf/d)	Natural Gas Liquids Gross (bbls/d)	Natural Gas Liquids Net (bbls/d)
Proved						
Developed producing	-	2,028	-	5,069	-	724
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	361	-	1,066	-	156
Total proved	-	2,389	-	6,135	-	881
Probable	-	397	-	950	-	140
Total proved plus probable[1]	**-**	**2,786**	**-**	**7,085**	**-**	**1,020**

Reserves Category	Total Oil Equivalent Gross (boe/d)	Total Oil Equivalent Net (boe/d)
Proved		
Developed producing	-	3,597
Developed non-producing	-	-
Undeveloped	-	695
Total proved	-	4,292
Probable	-	695
Total proved plus probable[1]	**-**	**4,987**

TOTAL

Reserves Category	Light and Medium Crude Oil Gross (bbls/d)	Light and Medium Crude Oil Net (bbls/d)	Tight Oil Gross (bbls/d)	Tight Oil Net (bbls/d)	Heavy Crude Oil Gross (bbls/d)	Heavy Crude Oil Net (bbls/d)
Proved						
Developed producing	-	2,036	-	2,295	-	1,089
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	344	-	406	-	178
Total proved	-	2,379	-	2,702	-	1,267
Probable	-	153	-	407	-	68
Total proved plus probable[1]	-	**2,533**	**-**	**3,109**	**-**	**1,335**

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	358	19,021	-	373	-	5,784
Developed non-producing	-	-	-	-	-	
Undeveloped	-	571	-	-	-	1,532
Total proved	358	19,592	-	373	-	7,316
Probable	4	697	-	3	-	987
Total proved plus probable[1]	**362**	**20,289**	**-**	**376**	**-**	**8,303**

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	4	1,388	64	11,005
Developed non-producing	-		-	
Undeveloped	-	187	-	1,466
Total proved	4	1,576	64	12,471
Probable	0	170	1	1,079
Total proved plus probable[1]	**5**	**1,745**	**65**	**13,550**

1. Columns may not add due to rounding.

Production History

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

CANADA

	2023 Quarter Ended				2022 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)	3,261	3,060	3,242	3,243	3,118	3,118	3,242	3,110
Heavy Crude Oil (bbls/d)	1,182	1,127	1,167	1,253	1,218	1,190	1,239	1,210
Conventional Natural Gas[3] (Mcf/d)	26,120	25,575	26,696	26,538	27,096	26,843	25,938	26,958
NGL (bbls/d)	863	729	942	903	925	783	888	980
Combined (boe/d)	**9,659**	**9,178**	**9,800**	**9,822**	**9,777**	**9,566**	**9,692**	**9,793**
Average price realized								
Light and Medium Crude Oil[2] ($/bbl)	93.16	102.13	91.79	86.48	98.62	110.76	132.41	106.48
Heavy Crude Oil ($/bbl)	72.49	87.16	66.57	61.47	78.06	91.18	117.55	98.09
Conventional Natural Gas[3] ($/Mcf)	2.02	2.05	1.94	3.29	4.90	4.73	6.30	4.20
NGL ($/bbl)	51.26	52.10	44.52	58.46	53.84	59.95	75.00	65.31
Combined ($/boe)	**50.34**	**54.61**	**47.86**	**50.66**	**59.85**	**65.63**	**83.04**	**64.09**
Royalty expense[4]								
Light and Medium Crude Oil[2] ($/bbl)	0.03	0.01	0.10	0.02	-	0.06	0.08	-
Heavy Crude Oil ($/bbl)	-	-	-	-	-	-	-	-
Conventional Natural Gas[3] ($/Mcf)	-	0.01	-	-	-	0.01	0.01	-
NGL ($/bbl)	0.07	0.19	0.19	0.13	0.02	0.46	0.39	0.23
Combined ($/boe)	**0.02**	**0.01**	**0.08**	**0.02**	**0.01**	**0.08**	**0.09**	**0.04**
Operating expenses ($/boe)[5]								
Light and Medium Crude Oil[2] ($/bbl)	-	-	-	-	-	-	-	-
Heavy Crude Oil ($/bbl)	-	-	-	-	-	-	-	-
Conventional Natural Gas[3] ($/Mcf)	0.10	0.10	0.13	0.07	0.10	0.07	0.13	0.06
NGL ($/bbl)	0.16	0.21	0.22	0.10	-	0.30	0.42	0.20
Combined ($/boe)	**0.27**	**0.29**	**0.38**	**0.21**	**0.28**	**0.22**	**0.39**	**0.18**
Netback received[6,7]								
Light and Medium Crude Oil[2] ($/bbl)	93.13	102.12	91.69	86.46	98.62	110.70	132.33	106.48
Heavy Crude Oil ($/bbl)	72.49	87.16	66.57	61.47	78.06	91.18	117.55	98.09
Conventional Natural Gas[3] ($/Mcf)	1.92	1.94	1.81	3.22	4.80	4.65	6.16	4.14
NGL ($/bbl)	51.03	51.70	44.11	58.23	53.82	59.19	74.19	64.88
Combined ($/boe)	**50.05**	**54.31**	**47.40**	**50.43**	**59.56**	**65.33**	**82.56**	**63.87**

1. Represents net production from our Royalty Lands in Canada and our minor working interest production 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 related to Freeholds working interest production.
5. Operating expenses relate to working interest production and 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]

	2023 Quarter Ended				2022 Quarter Ended			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average daily production[2]								
Tight Oil (bbls/d)	3,047	3,265	2,851	2,859	3,300	2,817	2,136	2,124
Shale Gas (Mcf/d)	6,849	7,276	6,676	6,948	6,648	5,476	5,399	5,887
NGL (bbls/d)	1,015	949	903	885	856	924	725	777
Combined (boe/d)	**5,204**	**5,427**	**4,867**	**4,902**	**5,264**	**4,653**	**3,761**	**3,883**
Average price realized								
Tight Oil ($/bbl)	108.51	108.54	99.92	100.28	116.97	121.31	138.70	118.63
Shale Gas ($/Mcf)	2.60	2.35	2.11	3.93	6.83	9.31	7.79	6.54
NGL ($/bbl)	26.01	27.67	27.46	31.16	38.22	39.10	47.74	45.20
Combined ($/boe)	**72.04**	**73.28**	**66.52**	**69.68**	**88.17**	**92.15**	**99.16**	**83.88**
Production and ad valorum taxes								
Tight Oil ($/bbl)	3.54	5.20	5.71	3.50	5.93	5.47	5.00	4.51
Shale Gas ($/Mcf)	0.59	0.87	0.95	0.58	1.00	0.90	0.83	0.77
NGL ($/bbl)	3.54	5.20	5.71	3.50	5.93	5.47	5.00	4.51
Combined ($/boe)	**3.54**	**5.20**	**5.71**	**3.50**	**5.93**	**5.46**	**4.98**	**4.50**
Operating expenses ($/boe)[3]								
Tight Oil ($/bbl)	-	-	-	-	-	-	-	-
Shale Gas ($/Mcf)	-	-	-	-	-	-	-	-
NGL ($/bbl)	-	-	-	-	-	-	-	-
Combined ($/boe)	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Netback received[4]								
Tight Oil ($/bbl)	104.97	103.34	94.21	96.78	111.04	115.84	133.70	114.12
Shale Gas ($/Mcf)	2.01	1.48	1.16	3.35	5.83	8.41	6.96	5.77
NGL ($/bbl)	22.47	22.47	21.75	27.66	32.29	33.63	42.74	40.69
Combined ($/boe)	**68.50**	**68.08**	**60.81**	**66.18**	**82.24**	**86.69**	**94.18**	**79.38**

1. Denominated in Canadian dollars.
2. Represents net production from our Royalty Lands in the United States.
3. 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.
4. Netbacks are calculated by subtracting royalty expenses and operating costs from revenues.

The following table summarizes our average daily production from our Royalty Lands in important regions or fields for the year ended December 31, 2023:

	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	1,061	879	24,346	763	6,761
Saskatchewan East	2,135	308	1,883	94	2,851
Canada Total	3,196	1,187	26,229	857	9,612

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.

	Tight Oil (bbls/d)	Shale Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
United States Royalty Lands[1]				
Eagle Ford	1,543	3,251	590	2,674
Permian	1,268	1,791	251	1,817
North Dakota and Other	196	1,895	98	611
United States Total	3,007	6,937	939	5,102

1. Production from the Royalty Lands is presented on a net basis.

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 natural gas properties. We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of our minor working interest properties upon abandonment. In 2023, our working interest assets represented 0.9% of our proven and probable reserves. Environment, health and safety falls under the responsibility of Rife as the 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 in the Trimble Report, 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, which is only applicable in relation to Freehold's working interest properties. In addition, abandonment, decommissioning and reclamation of pipelines and facilities were also taken into account for the purposes of estimating Reserves Data in the Trimble Report. As Freehold only holds royalty interests in the United States and no working interests, for the purposes of the Ryder Scott Report on Freehold's United States assets, no deduction has been made for abandonment, decommissioning and reclamation costs as the Corporation has no liability for such costs on its royalty interest properties. 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 $4.0 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 individual well, facility and pipeline level based on the underlying characteristics of the related well, facility or pipeline. 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, 2023, which is available on SEDAR+ at www.sedarplus.ca.

Borrowings

Freehold has extendible revolving credit facilities with a total commitment of $300 million consisting of a $285 million syndicated facility and a $15 million operating facility. The syndicated facility can be increased to up to $435 million pursuant to an accordion feature, subject to incremental lender commitments and certain conditions.

The current maturity date of the credit facilities is October 21, 2025. Freehold may annually request an extension of the then current maturity date, subject to approval by the lenders. Following the granting of any extension, the term to maturity of the credit facilities may not exceed three years.

Outstanding borrowings under the credit facilities bear interest on U.S. and Canadian denominated drawings at the Secured Overnight Financing Rate (SOFR) and Canadian Dollar Offered Rate (CDOR), respectively, or at the lender's prime lending rate plus applicable margins and standby fees, dependent on ratios of Freehold's long-term debt to earnings before interest, taxes, depreciation and amortization (EBITDA) on royalty interest properties. The publication of CDOR will cease after June 28, 2024, with this rate transitioning to Canadian Overnight Repo Rate Average (CORRA). Freehold does not expect this transition will cause a significant difference on the cost of its borrowings under the credit facility agreement.

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 at any time exceed 3.5 to 1.0; and 2 the ratio of our debt to capitalization (the aggregate of debt and Shareholders' equity) shall not at any time 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 by first charge demand debentures over all of Freehold's Canadian assets and a security agreement and fixed charge mortgage over certain of Freehold's U.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. 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 to 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, where as at December 31, 2023, the Corporation's Canadian 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. 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

The price of crude oil, natural gas, and natural gas liquids ("NGLs") is negotiated by buyers and sellers. A number of factors may influence prices, including (global, in some instances) supply and demand, quality of product, distance to market, availability of transportation, value of refined products, prices of competing products, price of competing stock, contract term, weather conditions, supply/demand balance, contractual terms of sale and, in some cases, regulatory restrictions and rules that may impact pricing.

Transportation Constraints and Market Access

Capacity to transport production from Western Canada to Eastern Canada, the United States and other international markets has been, and continues to be, a major constraint on the exportation of crude oil, natural gas and NGLs. Although certain pipeline and other transportation projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and 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 discounted commodity pricing relative to other markets in 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.

Pipelines in Canada

Under Canadian constitutional law, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the *Canadian Energy Regulator Act*, 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.

Pipelines in the United States

In the United States, transportation of crude oil is subject to rate and access regulation. The Federal Energy Regulatory Commission ("**FERC**") regulates interstate crude oil pipeline transportation rates under the Interstate Commerce Act of 1887 (the "**ICA**"). In general, such pipeline rates must be cost-based. The FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service. Such rates and terms and conditions may not be discriminatory or preferential. At the beginning of 1995, regulations adopted by the FERC generally grandfathered all previously approved interstate transportation rates and established an indexing system for such rates permitting annual adjustments based on the rate of inflation, subject to certain limitations. Every five years, the FERC examines the annual change compared to the actual cost changes. In December 2015, under the five-year re-determination, the FERC adjusted the index level used to determine annual changes to oil pipeline rate ceilings and determined that the Producer Price Index for Finished Goods ("**PPI-FG**") plus 1.23% should be the index level for the five-year period beginning July 1, 2016. In December 2020, the FERC adjusted the index level to be the PPI-FG plus 0.78% for the July 1, 2021 to June 30, 2026 time period. A pipeline may also file cost-of-service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Intrastate crude oil pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state.

Specific Pipeline Updates

The Trans Mountain Pipeline expansion, which will increase its capacity from 300,000 bbls/d to 890,000 bbls/d, received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government-owned Trans Mountain Corp. acquired the Trans Mountain Pipeline in August 2018. Following the resolution of various legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, the project budget has since been increased to $30.9 billion. The budget increase and in-service date delay have been attributed to, among other things, high global inflation, global supply chain challenges, the widespread flooding in British Columbia in late 2021 and unexpected major archeological discoveries. On June 1, 2023, Trans Mountain Corp. submitted an application to the Canada Energy Regulator proposing a base toll of $11-12 per barrel, which was met with great opposition; a multiple stage hearing process is underway, and decision has not yet been released. The federal government has been in discussions with Indigenous groups and businesses regarding selling significant equity stakes in the pipeline, however no agreements have yet been reached. The pipeline is expected to be in service in 2024, an extension from the initial December 2022 estimate, although the exact in-service date continues to be unknown.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system (which transports up to 540,000 bbls/d of light crude oil, light synthetic crude, and NGLs), to operate below the Straits of Mackinac, attempting to force the lines compromising this segment of the pipeline system to be shut down. Enbridge Inc. 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. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. In August 2022, the United States District Court for Western Michigan rejected the Attorney General of Michigan's efforts to move the dispute to Michigan state court, citing important federal interests at stake in having the dispute heard in federal court. Michigan's Attorney General intends to appeal the decision.

In September 2022, the District Court of Wisconsin ruled in favour of the Bad River Band in its dispute with Enbridge Inc. over the Enbridge Line 5 pipeline system in that state. Stopping short of ordering the system to be shut down, the court ruled that the Bad River Band is entitled to financial compensation and ordered Enbridge Inc. to reroute the pipeline around Bad River territory within five years.

Required repairs or upgrades to existing natural gas 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. In October 2020, TC Energy Corporation received federal approval to expand the NOVA Gas Transmission Line system (the "**NGTL System**"). The NGTL system is in the midst of implementing a $6.5 billion infrastructure program which added 1.3 billion cubic feet per day of capacity in 2022, and an additional 2.2 billion cubic feet per day of capacity is planned between 2023 and 2026.

Land Tenure

Mineral Rights in Canada

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.

Private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada, as well as 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 is Canadian federal government ownership of mineral rights on Indian reserves (as designated under the *Indian Act* (Canada)), which is managed and regulated by a separate government body according to distinct legislation. The Corporation does not have operations or royalty interests on Indian reserve lands.

Mineral Rights in the United States

Mineral interests in the United States may be owned privately or by the state or federal government. 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.

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 in Canada or lands owned by the state or federal government in the United States, 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 and some states have 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, facility or pipeline.

Royalties and Incentives

Each province (and in the case of the U.S., each state) has legislation and regulations in place to govern royalties due to government and establish the royalty rates that producers must pay in respect of the production of resources. The royalty regime in a given province or state is in addition to applicable federal and provincial or state taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. In Canada and the United States, royalties payable on production from lands where the government does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain taxes and other charges on production or revenues may be payable. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

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, both the federal and the provincial governments in Western Canada and some state governments in the United States 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.

In addition, from time to time, the Canadian federal government creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry and other industries in Canada.

In the United States, royalties payable for oil and gas production vary depending on whether the oil and gas estate is owned by the federal government, the state government or a private landholder. Generally, the current federal royalty rate for onshore oil and gas is 12.5%. Production may also be subject to oil and gas severance taxes at the state level, although such severance taxes may include exemptions available for low-producing wells. Royalties payable under private oil and gas leases in North Dakota are determined by negotiations between the mineral owner and the lessee.

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 greenhouse gas ("**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. Companies that have hydraulic fracturing operations have additional operational regulatory and reporting requirements.

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.

In recent years, there has been a number of laws enacted by the federal government that have been challenged by provincial governments as exceeding the federal government's powers under Canadian constitutional law and interfering with provincial areas of jurisdiction. For instance, the passing of Bill C-69, which included the Canadian Energy Regulator Act and the Impact Assessment Act ("**IAA**") by the federal government created additional uncertainty as they appeared to grant broad discretion to Canada to veto infrastructure projects (including infrastructure projects under provincial jurisdiction) based on broad and undefined criteria like sustainability. In 2023, the Supreme Court of Canada found that the IAA was unconstitutional largely on the basis that it represented significant federal overreach into provincial affairs. Since the decision on the IAA, the federal government has paused the assessment process under the IAA, in particular, halting the designation of projects for assessment until new legislation is introduced. Disputes and uncertainty over jurisdiction between Canada and the provinces and over the scope of environmental legislation have created significant barriers to major infrastructure projects in Canada.

United States

Oil and natural gas operations in the United States are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Oil and natural gas operations in the United States are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

Liability Management

The Alberta Energy Regulator (the "**AER**") administers several liability management programs to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The province is gradually moving from a prescriptive framework toward a more holistic approach to liability management.

Alberta has an orphan fund to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in certain of the AER's programs if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The orphan fund is funded through a levy and a loan from the provincial government.

The Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision), provides the backdrop for Alberta's approach to liability management. As a result of 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. The burden of a defunct licensee's abandonment and reclamation obligations first falls 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.

To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure.

Similar to Alberta, the B.C. regulator has moved away from the formulaic approach to liability management toward a more holistic assessment of a permit holder's ability to meet its abandonment and reclamation obligations. Additionally, similar to Alberta's orphan fund, B.C. and Saskatchewan have programs to address the abandonment and reclamation costs for orphan sites. The Government of Manitoba has not implemented a liability management rating program like those found in the other Western Canadian provinces, however, the province has an abandonment fund that may be used to operate or abandon a well or facility when the licensee or permittee fails to comply with the legislation, to rehabilitate the site of an abandoned well, or facility or to address any adverse effect on property caused by a well or facility.

The British Columbia Dormancy and Shutdown Regulation establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that have become dormant between 2019 and 2023 and will become dormant during or after 2024.

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. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40–45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference Canada pledged to: (i) reduce methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) cease to export thermal coal by 2030; (iii) impose a cap on emissions from the oil and gas sector; (iv) halt direct public funding to the global fossil fuel sector by the end of 2022; and (v) commit that all new vehicles sold in the country will be zero-emission on or before 2040. During the 2023 United Nations Climate Change Conference, which concluded on December 12, 2023, Canada signed an agreement with nearly 200 other parties, which includes renewed commitments to transitioning away from fossil fuels and further cutting GHG emissions.

In 2022, the federal government published a discussion paper that outlined two potential regulatory options for capping emissions: (i) to implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) to modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. The federal government has completed its formal engagement on potential regulatory options to cap emissions. In December 2023 it released the proposed regulatory framework and it expects to publish draft regulations in mid-2024. The form of emissions cap on the oil and gas sector and the overall effect of such a cap remain uncertain.

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 CO2e emissions. The GGPPA 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. Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50/tonne of CO2e in 2022. However, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. 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. Effective January 1, 2024, the minimum price permissible under the GGPPA rose to $80/tonne of CO2e.

While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment release on March 25, 2021.

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 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 regulations aim to reduce the oil and gas sector's methane emissions by 40-45% by 2025, relative to 2012.

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.

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis, to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The *Canadian Net-Zero Emissions Accountability Act* (the "**CNEAA**") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires 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. A comprehensive review of the CNEAA is required every five years from the date the CNEAA came into force.

The Government of Canada introduced its 2030 Emissions Reduction Plan (the "**2030 ERP**") on March 29, 2022. In the 2030 ERP, the Government of Canada proposes a roadmap to reduce its GHG emissions to 40-45% below 2005 levels by 2030. As the first emissions reduction plan issued under the CNEAA, the 2030 ERP aims to reduce emissions by incentivizing electric vehicles and renewable electricity, and capping emissions from the oil and gas sector, among other measures.

On June 8, 2022 the Canadian Greenhouse Gas Offset Credit System Regulations were published in the Canada Gazette. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the OBPS or those seeking to meet voluntary targets.

On June 20, 2022, the federal Clean Fuel Regulations came into force and in July 2023 they took effect. The Clean Fuel Regulations aim to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives imposing obligations on primary suppliers of transportation fuels in Canada and requiring fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

Additionally, on December 7, 2023, the Minister of Environment and Climate Change and the Minister of Energy and Natural Resources, introduced Canada's draft cap-and-trade framework to limit emissions from the oil and gas sector. The proposed Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap proposes capping 2030 emissions at 35 to 38 percent below 2019 levels, while providing certain flexibilities to emit up to a level around 20 to 23 percent below 2019 levels. The purpose of the proposed cap is to ensure that Canada is on track to meet its target of achieving net-zero by 2050. The federal government is collecting feedback from the public on the proposed framework until February 5, 2024. It is expected that the regulations will be finalized and released sometime in 2025 with annual reporting required as early as 2026 and a phasing in period taking place between 2026 and 2030.

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. As part of the 2021 budget, the federal government committed to investing $319 million over seven years to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050. The House of Commons is currently considering legislation pursuant to which it will start paying subsidies for carbon capture and net-zero energy projects; an update is expected in early 2024.

In June 2023, the International Financial Reporting Standards Foundation ("**IFRS**") issued two international reporting standards on sustainability: IFRS S1, which addresses sustainability-related disclosure, and IFRS S2, which addresses climate-related disclosure. The new standards require issuers, among other things, to include quantitative data regarding their climate change considerations, to use scenario analysis in developing their disclosure, and to disclose Scope 3 GHG emissions. While Canadian companies are not required to follow IFRS S1 and IFRS S2 at this time, the Canadian Securities Administrators is considering amending Canadian reporting requirements to include the new international standards, however to what extent they will be adopted remains unclear.

Provincial

In December 2016, the *Oil Sands Emissions Limit Act* (Alberta) 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. The delay in drafting these regulations has been inconsequential thus far, as Alberta's oil sands emit roughly 81 megatonnes of GHG emissions per year, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On January 1, 2024, the carbon tax payable in Alberta increased from $65 to $80 per tonne of CO2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. 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 (as amended on January 1, 2023) and replaced the previous *Carbon Competitiveness Incentives Regulation*. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The GGPPA system applies in part in Saskatchewan for specific industry sectors, and the federal backstop continues to apply to emissions sources not covered by the provincial emissions legislation. In Manitoba, the federal system applies in full, whereas it does not apply in British Columbia, which has its own system altogether.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the Methane Emission Reduction Regulation on January 1, 2020, and 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.

Similarly, the Government of Saskatchewan released its Methane Action Plan in 2019, which sets concrete goals to reduce its methane emissions, and in 2020, B.C. introduced regulations to reduce methane emissions.

United States

In the United States, the EPA has finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. In addition, certain states have taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. States have also imposed increasingly stringent requirements related to the venting or flaring of gas during oil and natural gas operations.

Although the U.S. had withdrawn from the Paris Agreement, it formally rejoined in February 2021. The United States has established an economy-wide target of reducing its net GHG emissions by 50-52% below 2005 levels in by 2030, and achieving net-zero GHG emissions economy-wide by no later than 2050.

The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations and financial results. In addition to the federal legislative and regulatory changes, in several U.S. states, the regulatory authorities are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to oil and gas facilities.

Indigenous Rights in Canada

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights 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 on 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 June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to 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. On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"). The Progress Report provides that, as of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP (the "**Implementation Secretariat**"), consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP's, and implementing efforts to educate federal departments on UNDRIP principles. On June 21, 2023, the Implementation Secretariat released The United Nations Declaration on the Rights of Indigenous Peoples Act Action Plan with respect to aligning federal laws with UNDRIP, which has a 2023-2028 implementation timeframe.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward.

On June 29, 2021, the British Columbia Supreme Court issued a judgement in *Yahey v British Columbia* (the "**Blueberry Decision**"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("**BRFN**") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. The Blueberry Decision may have significant impacts on the regulation of industrial activities in northeast British Columbia, and may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties, as has been seen in Alberta.

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nations Implementation Agreement (the "**BRFN Agreement**"). The BRFN Agreement aims to address cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a $200-million restoration fund by June 2025, an ecosystem-based management approach for future land-use planning in culturally important areas, limits on new petroleum and natural gas development, and a new planning regime for future oil and gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on petroleum and natural gas revenue sharing and provincial royalty revenue sharing in the next two fiscal years.

The BRFN Agreement has acted as a blueprint for other agreements between the Government of British Columbia and Indigenous groups in Treaty 8 territory. In late January 2023, the Government of British Columbia and four Treaty 8 First Nations – Fort Nelson, Salteau, Halfway River and Doig River First Nations – reached consensus on a collaborative approach to land and resource planning (the "**Consensus Agreement**"). The Consensus Agreement implements various initiatives including a "cumulative effects" management system linked to natural resource landscape planning and restoration initiatives, new land-use plans and protection measures, and a new revenue sharing approach to support the priorities of Treaty 8 First Nations communities.

In July 2022, Duncan's First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by the BRFN. Duncan's First Nation claims in its lawsuit that Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation's treaty rights. Beaver Lake Cree Nation brought a similar lawsuit against the Government of Alberta in 2008, which had stalled, but is scheduled to be heard in January 2024. The long-term impacts of the Blueberry Decision and the Duncan's First Nation's and Beaver Lake Cree Nation's lawsuits on the Canadian oil and gas industry remain uncertain and could ultimately end up in lawsuits and claims relating to Indigenous rights or require provincial governments to negotiate agreements with Indigenous groups with respect to future development of oil and natural gas properties leading to uncertainty about future development and operations.

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.

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 of the Corporation's reserves 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 may be volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, the Russian Ukrainian war and conflicts in the Middle East, or other adverse economic or political developments in the United States, Europe, or Asia. 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 Market Access*".

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 and natural gas. 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, third party challenges to regulatory decisions and orders can reduce the efficiency of the regulatory regime, as the implementation of decisions and orders may be delayed resulting in uncertainty and interruption to the business of the oil and natural gas industry. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation"*.

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*".

Royalty Regimes

Governments in the jurisdictions in which the Corporation has assets may adopt new royalty regimes, or modify the existing royalty regimes, which may impact 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*".

Israel-Palestine War

On October 7, 2023, Hamas terrorists infiltrated Israel's southern border from the Gaza Strip and conducted a series of attacks on civilian and military targets. Hamas also launched extensive rocket attacks on the Israeli population and industrial centres located along Israel's border with the Gaza Strip and in other areas within the State of Israel. Following the attack, Israel's security cabinet declared war against Hamas and the military campaign against these terrorist organizations has launched a series of responding attacks in Palestine. The outcome of the conflict has the potential to have wide-ranging consequences on the world economy. Global oil prices have increased since the beginning of the Israel-Palestine war. While neither Israel nor the Gaza Strip are significant oil producers, there is a risk that the conflict could lead to wider regional instability in the Middle East, home to some of the world's biggest oil producers. The long-term impacts of the conflict remain uncertain and the Corporation continues to monitor the evolving situation.

Russian Ukrainian War

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. Many countries throughout the world have provided aid to the Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in their resistance to the Russian invasion. The North Atlantic Treaty Organization ("**NATO**") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region.

In addition, certain countries including Canada and the United States, have imposed financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. The outcome of the ongoing conflict remains uncertain and may have wide-ranging consequences on the peace and stability of the regain and the world economy.

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, 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. 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 7% of Freehold's total royalty production in 2023. 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

Most 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 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. This 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 effect on the Corporation's financial and operational results.

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, current perceptions of the oil and natural gas market and worldwide pandemics. 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.

Geopolitical Risks

The Corporation's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact the Corporation's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licenses and permits for the Corporation's activities or restrict the operation of third party infrastructure on which the Corporation relies. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact the Corporation's results.

Other government and political factors that could adversely affect the Corporation's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Corporation's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources. The success of these initiatives may decrease demand for the Corporation's products.

A change in federal, provincial, state or municipal governments in Canada or the United States 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 oil and natural gas industry has become an increasingly politically polarizing topic, resulting in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Corporation's activities. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Transportation Constraints and Market Access*".

In addition, conflicts, or conversely peaceful developments, arising outside of Canada, including the current conflicts in Palestine and Ukraine and 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.

Inflation and Rising Interest Rates

Recently Canada, the United States and other countries have experienced high levels of inflation, supply chain disruptions, equipment limitations, escalating supply costs and commodity prices. These factors have resulted in the escalation of operating costs of the Corporation's royalty payors. The inability of the Corporation's royalty payors to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows of the Corporation.

In addition, many central banks, including the Bank of Canada and U.S. Federal Reserve, have taken steps to raise interest rates in an attempt of combat inflation. The rise in interest rates has impacted the Corporation's borrowing costs and the borrowing costs of the Corporation's royalty payors. Increased borrowing costs could impact the ability of the Corporation to pay dividends. The increase in borrowing costs may also impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows of the Corporation. The rising interest rates could also result in a recession in Canada, the United States or other countries in the world. A recession may have a negative impact on demand for oil and natural gas which would result in a decrease in commodity prices. A decrease in commodity prices would immediately impact the Corporation's revenues and cash flows and could also reduce drilling activity on the Corporation's properties. It is unknown how long inflation will continue to impact the economies of Canada and the United States and the impact inflation and rising interest rates will have on demand for oil and gas and commodity prices.

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, extreme cold 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 may be unable to execute projects on time, on budget, or at all.

Gathering and Processing Facilities, Pipeline Systems, Trucking 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 truck and 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, trucking and railway lines. 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.

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, process, 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, potentially in a material way.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of oil, liquids and natural gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing has resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity or completely banning hydraulic fracturing in other areas. 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, liquids and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions or bans on hydraulic fracturing in the areas where the Corporation has royalty interests could result in the Corporation being unable to economically recover its oil and gas reserves and reserves, which would result in a significant decrease in the value of the Corporation's assets.

Water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on the Corporation's royalty payors' ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact the operations of such royalty payors. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Corporation's royalty payors are unable to obtain water to use in their operations from local sources, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Cost increases could have a material adverse effect on drilling economics resulting in delays or suspensions of drilling which ultimately would have a detrimental effect on the financial condition, results of operations, and cash flows of the Corporation.

The Corporation's royalty payors must dispose of the fluids produced from oil and natural gas production operations, including produced water. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities. Over the past year, the Permian Basin has experienced an increase in seismic activity. According to seismologists, the most probable cause is the injection of saltwater into underground formations for disposal. This saltwater is produced in the oil and gas extraction process, separated from the oil and gas, and often disposed of underground. In response to such seismic activity, the Railroad Commission of Texas, which is responsible for regulating the exploration, production, and transportation of oil and natural gas in Texas, has implemented certain measures and may enact more with respect to saltwater disposal in the Permian Basin. In addition, in response to similar seismic activity in Oklahoma from 2010 and 2015, the regulatory authorities in Oklahoma established additional regulations and restrictions on produced water injection.

If oil and gas operators in the Permian Basin or other areas where Freehold has interests are unable to find alternative methods of disposal to formation injection, such operators may need to curtail hydrocarbon production pending implementation of a commercially reasonable solution, which could impact the operations of the Corporation's royalty payors.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Corporation's royalty payors or by commercial disposal well vendors that the Corporation's royalty payors may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Corporation's royalty payors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Corporation or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Corporation's business, financial condition, and results of operations.

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 – 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 liabilities and potentially increased capital expenditures and operating costs. Oil and gas exploration and development has the potential to impact environmental quality through land disturbance, biodiversity impacts, and emissions to air and water. Landowners are increasingly demanding a minimization of surface footprint and some require offsets or mitigation measures to ensure land and biodiversity remain pristine and protected. 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 is 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.

Climate Change

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries, including Canada and the United States, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. At the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and at the 2023 United Nations Climate Change Conference, Canada renewed its commitments to transitioning away from fossil fuels and further cutting GHG emissions.

Transition Risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multi-lateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes, methane fees and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the operating expenses of some of the Corporation's royalty payors, and, in the long-term, potentially reducing the demand for oil and natural gas and related products, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. Individuals, governmental authorities, or other organizations may make claims against oil and natural gas companies, including the Corporation, for alleged personal injury, property damage, or other potential liabilities. While the Corporation is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Corporation, impact its operations and have an adverse impact on its financial condition.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG-intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to oil and natural gas and related infrastructure businesses and projects. The impact of such efforts require the Corporation's management to dedicate significant time and resources to these climate change-related concerns, which may adversely affect the Corporation's operations, the demand for and price of the Corporation's securities and the Corporation's cost of capital and access to the capital markets.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, in June 2023 the International Sustainability Standards Board issued two new international sustainability disclosure standards with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. The Canadian Securities Administrators had previously published for comment Proposed National Instrument 51-107 – *Disclosure of Climate-Related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada. It is expected that the introduction of the new international standards will instruct how new Canadian sustainability disclosure standards are finalized. If the Corporation is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Climate Change Regulation*".

Physical Risks

Based on the Corporation's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the ability of the Corporation's royalty payors to access their properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions.

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 in 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 of funds 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.

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

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 those 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 miss certain acquisition opportunities.

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 miss certain acquisition opportunities. 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 acquire additional properties 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 or acquisition plans may result in a delay in development of or production from 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.

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, such financing 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 entered into hedges related to the expected future cash flow of royalty production, 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 or natural gas prices.

Similarly, from time to time, the Corporation may enter into agreements to fix the exchange rate of Canadian dollars 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.

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 crude 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 crude 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 crude oil and bitumen to market. An increase to the cost of bringing heavy crude 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 crude 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.

The Corporation's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the Corporation to decide to reduce or possibly eliminate, coverage. In addition, insurance is purchased from a number of third party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the Corporation's overall risk exposure could be increased and the Corporation could incur significant costs.

Non-Governmental Organizations

In addition to the risks outlined above related to geopolitical developments, the oil and natural gas properties, wells and facilities of the Corporation and its partners and royalty payors could, 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 by any negative public opinion toward 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 such groups' 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 the environment 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 toward 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 toward investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they are no longer 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 of Directors 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 limit 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.

Indigenous Land and Rights Claims

Opposition by Indigenous groups of the operations, development or exploratory activities of oil and gas companies in any of the jurisdictions in which the Corporation has interests may negatively impact it in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact the Corporation's royalty payors' progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. Although there are no Indigenous and treaty rights claims on lands where the Corporation operates, no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on the Corporation's operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Corporation's royalty payors' ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, a recent British Columbia Supreme Court decision determined that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nations group in northeast British Columbia breached that group's treaty rights. Recently, the Government of British Columbia and the First Nations group have come to an agreement relating to further industrial activities in the area, which will have an impact on such industrial activities in the area. The developments in northeastern British Columbia relating to Indigenous rights, may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties. The long-term impacts and associated risks of the decision on the Canadian oil and natural gas industry and the Corporation remain uncertain.

In addition, the federal government has introduced legislation to implement the UNDRIP. Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or have begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain. Additional processes may be created or legislation associated with project development and operations may be amended or introduced, further increasing uncertainty with respect to project regulatory approval timelines and requirements. See "*Industry Conditions – Indigenous Rights*".

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. To continue to manage the growth of the Corporation effectively, the Manager will need to continue to implement and improve its operational and financial systems and to train, manage and potentially expand 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 a licence or lease, fails to meet the specific requirement of the 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, restrictions under contracts on the payment of dividends 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 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, be 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 effect on the Corporation's financial condition.

For additional information, see "*Legal Proceedings and Regulatory Actions*".

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 would 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

We are subject to taxes in Canada and the U.S. Due to economic and political conditions, tax rates in various jurisdictions may be subject to significant change. Our effective tax rates could be affected by changes in the mix of earnings in countries with differing statutory tax rates, changes in the valuation of deferred tax assets and liabilities, or changes in tax laws or their interpretation.

Additionally, 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.

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, state and foreign tax legislation however 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.

Freehold has been assessed by the CRA to deny the deduction of certain non-capital losses claimed and carried forward in its 2015, 2018, 2019, 2021 and 2022 tax returns. Freehold is defending its tax filing position and expects it will be successful however, if Freehold is not successful it will have additional tax liability owing to the CRA. 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, municipal, 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). 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.

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.

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.

The protection of customer, employee, and company data is critical to the Corporation's business. The regulatory environment in Canada surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and constantly changing requirements. Certain legislation, including the *Personal Information Protection and Electronic Documents Act* in Canada, require documents to be securely destroyed to avoid identity theft and inadvertent disclosure of confidential and sensitive information. A significant breach of customer, employee, or company data could attract a substantial amount of media attention, damage the Corporation's customer relationships and reputation, and result in lost sales, fines, or lawsuits. In addition, an increasing number of countries have introduced and/or increased enforcement of comprehensive privacy laws or are expected to do so. The continued emphasis on information security as well as increasing concerns about government surveillance may lead customers to request the Corporation to take additional measures to enhance security and/or assume higher liability under its contracts. As a result of legislative initiatives and customer demands, the Corporation may have to modify its operations to further improve data security. Any such modifications may result in increased expenses and operational complexity, and adversely affect its reputation, business, financial condition and results of operations.

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 place. 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 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 AIF.

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 and any gain from the sale of Common Shares by 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.

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 150,689,334 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**
2023				
January	16.23	14.695	16.08	14,076,944
February	16.26	15.04	15.48	12,436,454
March	16.32	13.60	14.53	13,561,518
April	15.44	14.51	14.75	6,832,770
May	14.92	13.59	14.00	8,356,783
June	14.61	12.91	13.44	8,194,090
July	14.46	13.11	13.93	8,408,673
August	14.73	13.68	14.38	6,491,244
September	15.27	14.55	14.70	6,239,461
October	14.99	13.62	14.28	6,811,103
November	15.06	13.90	13.93	7,203,991
December	14.25	12.66	13.69	7,943,824
2024				
January	14.36	13.51	13.93	6,331,535
February (1 – 27)	14.26	13.46	14.24	7,406,239

Prior Sales

Other than Deferred Share Units ("**DSUs**") and Restricted Share Units ("**RSUs**") (the DSUs and RSUs together, the "**Share Units**"), Freehold did not issue any securities of a class that are not listed or quoted on the market place during the year ended December 31, 2023.

We issued the following DSUs and RSUs (including notional DSUs and RSUs resulting from dividends) redeemable to acquire an equal number of Common Shares (less tax withholding) pursuant to the Deferred and Restricted Share Unit Plan during the year ended December 31, 2023:

Date	Number and Type of Share Units	Deemed Price per Share Unit
January 1, 2023	45,246 DSUs	$15.83
January 1, 2023	17,293 RSUs	$15.83
January 15, 2023	2,777 DSUs[1]	$15.60
February 15, 2023	2,945 DSUs[1]	$16.18
February 15, 2023	96 RSUs[1]	$16.18
March 15, 2023	3,257 DSUs[1]	$14.71
March 15, 2023	106 RSUs[1]	$14.71
March 30, 2023	2,031 DSUs[2]	$14.46
April 17, 2023	3,146 DSUs[1]	$15.38
April 17, 2023	102 RSUs[1]	$15.38
May 15, 2023	3,432 DSUs[1]	$14.18
May 15, 2023	112 RSUs[1]	$14.18
June 15, 2023	3,680 DSUs[1]	$13.31
June 15, 2023	120 RSUs[1]	$13.31
June 30, 2023	2,194 DSUs[2]	$13.39
July 17, 2023	3,551 DSUs[1]	$13.94
July 17, 2023	115 RSUs[1]	$13.94
August 15, 2023	3,109 DSUs[1]	$14.58
August 15, 2023	111 RSUs[1]	$14.58
September 15, 2023	3,048 DSUs[1]	$14.96
September 15, 2023	109 RSUs[1]	$14.96
September 29, 2023	1,965 DSUs[2]	$14.95
October 16, 2023	3,157 DSUs[1]	$14.59
October 16, 2023	112 RSUs[1]	$14.59
November 15, 2023	3,083 DSUs[1]	$15.03
November 15, 2023	109 RSUs[1]	$15.03
December 15, 2023	3,461 DSUs[1]	$13.47
December 15, 2023	123 RSUs[1]	$13.47
December 29, 2023	2,146 DSUs[2]	$13.69

1. Issued as notional DSUs or RSUs resulting from the payment of dividends of the Common Shares.
2. Issued in lieu of quarterly directors' fees based on directors' elections.

Escrowed Securities

To our knowledge, none of our securities are held in escrow or subject to a contractual restriction on transfer.

Dividends

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2023, our legal stated capital was $361 million.

Monthly dividends of Freehold are currently declared for Shareholders of record as of the last business 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 Shareholders. 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, 2024, Freehold has declared a cash dividend of:

- $0.09 per Common Share for Shareholders of record on January 31, 2024, which was paid on February 15, 2024;
- $0.09 per Common Share for Shareholders of record on February 29, 2024, which is payable on March 15, 2024; and
- $0.09 per Common Share for Shareholders of record on March 28, 2024, which is payable on April 15, 2024.

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
2021		
January 31, 2021	February 16, 2021	0.0200
February 28, 2021	March 15, 2021	0.0200
March 31, 2021	April 15, 2021	0.0300
April 30, 2021	May 17, 2021	0.0300
May 31, 2021	June 15, 2021	0.0400
June 30, 2021	July 15, 2021	0.0400
July 31, 2021	August 16, 2021	0.0400
August 31, 2021	September 15, 2021	0.0500
September 30, 2021	October 15, 2021	0.0500
October 31, 2021	November 15, 2021	0.0500
November 30, 2021	December 15, 2021	0.0600
December 31, 2021	January 17, 2022	0.0600
		0.4900

Record Date	Payment Date	Cdn$ per Share
2022		
January 31, 2022	February 15, 2022	0.0600
February 28, 2022	March 15, 2022	0.0600
March 31, 2022	April 18, 2022	0.0800
April 29, 2022	May 16, 2022	0.0800
May 31, 2022	June 15, 2022	0.0800
June 30, 2022	July 15, 2022	0.0800
July 29, 2022	August 15, 2022	0.0800
August 31, 2022	September 15, 2022	0.0900
September 30, 2022	October 17, 2022	0.0900
October 31, 2022	November 15, 2022	0.0900
November 30, 2022	December 15, 2022	0.0900
December 30, 2022	January 16, 2023	0.0900
		0.9700

Record Date	Payment Date	Cdn$ per Share
2023		
January 31, 2023	February 15, 2023	0.0900
February 28, 2023	March 15, 2023	0.0900
March 31, 2023	April 17, 2023	0.0900
April 28, 2023	May 15, 2023	0.0900
May 31, 2023	June 15, 2023	0.0900
June 30, 2023	July 17, 2023	0.0900
July 31, 2023	August 15, 2023	0.0900
August 31, 2023	September 15, 2023	0.0900
September 29, 2023	October 16, 2023	0.0900
October 31, 2023	November 15, 2023	0.0900
November 30, 2023	December 15, 2023	0.0900
December 29, 2023	January 15, 2024	0.0900
		1.0800

Passive Foreign Investment Company

In consultation with its U.S. tax advisors, Freehold believes it should be classified as PFIC under United States federal income tax principles. As such, dividends to and any gain from the sale of Common Shares by 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 16.66% 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, among other things, 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 $15 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities and hedging; (e) filling vacancies among the directors or appointing additional directors, other than nominees of the Manager; (f) disclosure required pursuant to applicable securities laws; (g) Freehold's legal structure, name, logo, vision and mission statement; and (h) 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 February 28, 2024, the Board of Directors was comprised of nine individuals. The name, province of residence, position held and principal occupation of each director of Freehold are as follows:

Name and Province or State of Residence	Position with Freehold	Principal Occupation	Director Since
Sylvia K. Barnes Texas, United States	Director	Corporate Director	June 1, 2022
Gary R. Bugeaud[1,2] Alberta, Canada	Director	Corporate Director	May 14, 2015
Peter T. Harrison[4] Quebec, Canada	Director	Consultant, CN Investment Division	July 29, 1996[5]
Maureen E. Howe[1,2] British Columbia, Canada	Director	Corporate Director	February 1, 2022
J. Douglas Kay[2,3] Alberta, Canada	Director	Corporate Director	May 11, 2016
Valerie A. Mitchell[3] Oklahoma, United States	Director	President and Chief Operating Officer, Troy Energy	June 1, 2022
Marvin F. Romanow Alberta, Canada	Chair of the Board of Directors	Corporate Director	May 14, 2015
David M. Spyker[4] 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, Finance and Risk Committee. Ms. Howe is Chair of the Audit, Finance and Risk Committee.
2. Member of Governance, Nominating and Compensation Committee. Mr. Kay is Chair of the Governance, Nominating and Compensation Committee.
3. Member of Reserves Committee. Mr. Walsh is Chair of the Reserves Committee.
4. Directors nominated for election at the last Annual Meeting of Shareholders held on May 10, 2023 by the Manager pursuant to the Governance Agreement.
5. Reflects the date of election or appointment as a member of the Board of Directors prior to completion of the plan of arrangement on January 1, 2011 that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust.

Officers of Freehold

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

Name and Province of Residence	Position with Freehold	Principal Occupation	Officer Since
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

Name and Province of Residence	Position with Freehold	Principal Occupation	Officer Since
Lisa N. Farstad Alberta, Canada	Vice President, Corporate Services	Vice President, Corporate Services of Rife	March 1, 2020
Brianna E. C. Guenther Alberta, Canada	General Counsel and Corporate Secretary	General Counsel and Corporate Secretary of Rife	September 6, 2022
Ian C. Hantke Alberta, Canada	Vice President, Diversified Royalties	Vice President, Diversified Royalties of Rife	January 1, 2022
Robert A. King Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Rife	January 6, 2020
Susan J. Nagy Alberta, Canada	Vice President, Business Development	Vice President, Business Development of Rife	April 1, 2023

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 February 28, 2024, the directors and executive officers of Freehold, as a group, beneficially owned or controlled, directly or indirectly, 595,737 Common Shares or less than 1% of the issued and outstanding Common Shares. CN Pension Trust Funds, owned, directly or indirectly, 25,104,464 Common Shares (approximately 16.66%) as at February 28, 2024. From 1996 to February 28, 2024, the Manager has received 3,887,450 Common Shares in payment of the Management Fee.

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

Sylvia K. Barnes

Ms. Barnes is a Corporate Director with over 30 years' experience in energy investment banking and a background in engineering. She is co-founder of Tanda Resources LLC, a privately-held energy advisory firm focused on upstream investments and consulting based in Houston, Texas. She currently serves on the board of StoneBridge Acquisition Corp. a special purpose acquisition company listed on the Nasdaq stock exchange. Ms. Barnes is a member of the National Association of Corporate Directors and is Chair of the Santa Mara Hostel Foundation. She has a Bachelor of Science degree in Mechanical Engineering from the University of Manitoba, and a Master of Business Administration from York University.

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 a consultant for CN Investment Division (Montreal), which manages one of the largest corporate pension funds in Canada. Prior to July 2022, Mr. Harrison was the Manager, Resource and Royalties of the CN Investment Division. Mr. Harrison has spent over 40 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 of Directors. 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. He is a member of the Institute of Corporate Directors.

Maureen E. Howe

Ms. Howe is a Corporate Director with substantial finance and capital market experience as well as relevant public company experience. Formerly a Managing Director, Equity Research, Energy Infrastructure at RBC Capital Markets, she specialized in the area of energy infrastructure, which included power generation, transmission and distribution, oil and gas transmission and distribution, gas processing and alternative energy. Prior to joining RBC Capital Markets, Ms. Howe held various positions in the area of capital markets, including investment banking, underwriting, project analysis, portfolio management, investment relations, and corporate finance. Ms. Howe is a director of Methanex Corporation and Pembina Pipeline Corporation. Ms. Howe holds a Bachelor of Commerce (Honours) from the University of Manitoba and a Ph.D. in Finance from the University of British Columbia. She is a member of the Institute of Corporate Directors.

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 board of Westbrick Energy Ltd. as Chairman and is a former director and Chair of the Explorers and Producers Association of Canada (EPAC).

Valerie A. Mitchell

Ms. Mitchell is a Corporate Director with over 25 years experience in the energy industry. Since March 2020, Ms. Mitchell has been the President and Chief Operating Officer of Troy Energy, a private independent oil and gas acquisition, development, and exploration company based in Oklahoma City. From 2016 through 2020, Ms. Mitchell was the Chief Executive Officer and a director of Corterra Energy, LLC, a private equity backed exploration and production company based in Tulsa, Oklahoma. She is currently a director and member of the Audit Committee of NCS Multistage Holdings Inc. She has a Bachelor of Science (Honours) in Chemical Engineering from the University of Missouri.

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 board of 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

Mr. Spyker was appointed President and Chief Executive Officer of Freehold in January 2021. From September 2020 to January 2021 Mr. Spyker served as Interim President and Chief Executive Officer for Freehold. Mr. Spyker joined Freehold in November 2016 as Vice President, Production and was appointed Chief Operating Officer in March 2019. Prior to joining, he held various roles at Anderson Exploration Ltd., Anderson Energy Ltd., and Anderson Energy Inc. Mr. Spyker has over 35 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). He is a member of the Institute of Corporate Directors.

David W. Hendry

Mr. Hendry is our Vice President, Finance and Chief Financial Officer. He joined Freehold in December 2019. Prior to joining Freehold, Mr. Hendry served as Chief Financial Officer of Obsidian Energy Ltd. from January 2017 to November 2019 and served as Vice President, Finance of Obsidian Energy Ltd. 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 30 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 of Freehold in March 2020. She joined the organization in September of 2015 as Manager, Human Resources and Information Services. Prior to joining the organization, 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.

Brianna E. C. Guenther

Ms. Guenther was appointed General Counsel and Corporate Secretary of Freehold on September 6, 2022. Prior to joining Freehold, from 2019 through 2022, Ms. Guenther was Senior Legal Counsel at Energy Transfer Canada ULC and from 2018 through 2019, Ms. Guenther was Corporate Secretary and Legal Counsel of Northview Apartment REIT. Prior to 2018, Ms. Guenther practiced law at Burnet, Duckworth & Palmer LLP as a corporate commercial lawyer. Ms. Guenther holds a Masters of International Business and Economic Law (with Distinction) from Georgetown University, a Juris Doctor (Dean's Honours List) from Queen's University and a Bachelor of Health Sciences (First Class Honours) from the University of Calgary. Ms. Guenther is a member of the Law Society of Alberta.

Ian C. Hantke

Mr. Hantke was appointed Vice President, Diversified Royalties of Freehold on January 1, 2022. He joined the organization in February 2014, and held various roles within the Business Development Group, most recently Director, Acquisitions. Prior to joining, Mr. Hantke spent two years working at Devon Energy as a Project Manager and seven years working at O'Rourke Engineering as a Facilities Engineer. Mr. Hantke has a Bachelor of Aerospace Engineering degree from Carleton University and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Robert A. King

Mr. King is our Chief Operating Officer. From January 2020 to April 2023, Mr. King served as Vice President, Business Development of Freehold. Prior to joining Freehold, Mr. King was 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.

Susan J. Nagy

Ms. Nagy is our Vice President, Business Development. She joined Freehold in April 2008 and was appointed as an officer in April 2023. She previously held various positions of increasing seniority within the Land and Business Development groups, including most recently as Director, Business Development. Ms. Nagy has a Bachelor of Commerce degree (with Distinction) from the University of Calgary and is an active member of the Canadian Association of Land and Energy Professionals (CALEP), Petroleum Acquisition & Divestment Association (PADA) and the American Association of Professional Landmen (AAPL).

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; or (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 AIF, 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*.

Ms. Barnes was appointed to the Board of Directors of Ultra Petroleum Corp. by the Second Lien Noteholders Special Committee in February 2019 and was a director of the company when it filed for bankruptcy in 2020.

Personal Bankruptcies

None of the directors or executive officers of Freehold nor any Shareholder holding sufficient number of securities of Freehold to affect materially the control of Freehold has, 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, Finance & Risk Committee

The full text of the Audit, Finance & Risk Committee mandate is included in Appendix C of this AIF.

Composition of Audit, Finance & Risk Committee (the "Audit Committee")

Freehold's Audit Committee consists of Ms. Maureen Howe (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*" and one member is considered a financial expert.

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	
	2023	2022
Audit fees[1]	$370,488	$335,980
Audit-related fees[2]	-	-
Tax fees[3]	$81,509	$83,307
All other fees	-	-
Total	**$451,997**	**$419,287**

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 including the filings of prospectuses by the Corporation in respect of public financings completed by the Corporation. 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 2023 and 2022, $53,200 and $12,800, respectively, of such fees were related to tax compliance and tax preparation and the remainder was for advisory services.

The Manager

Business of the Manager

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

Employees

Freehold has no employees but rather is managed by the Manager pursuant to the Management Agreement. On December 31, 2023, Rife had 99 full and part-time employees in the Calgary office and 6 full-time employees in their field operations, the majority of whom are on contract to the Manager. In addition to providing management services to Freehold, Rife's employees also manage the business of Rife, Canpar and certain other Rife affiliate entities.

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, farm-in 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 and the U.S. 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. Either the Manager or Freehold can terminate the Management Agreement at any time by providing six months written notice prior to the date of such termination. In addition, if a "Change of Control" (as defined in the Management Agreement) of Freehold occurs, 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.

Freehold 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 (or the lump sum cash equivalent) quarterly as payment of the Management Fee. In 2019, 2020, 2021, 2022 and 2023 an aggregate of 220,000, 165,000, 110,000, 55,000 and 22,000 Common Shares, respectively, were issued to the Manager as payment of the Management Fee. As at January 1, 2024, the quarterly Management Fee was 5,500 Common Shares (or the lump sum cash equivalent) per quarter (in accordance with the terms of the Management Agreement) and under the terms of the Management Agreement, the Management Fee will remain at that level for future years.

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 2023 – 56%). 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).

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 2023, a total of 101,329 (2022 – 105,717) restricted awards and 130,695 (2022 – 132,898) performance awards were granted to employees of Rife under the Freehold incentive award plan. 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 (2023 – 56%) of annual cash bonuses paid under the Rife short-term incentive plan for employees of the Manager.

Directors' Deferred and Restricted Share Unit Plan

The Deferred and Restricted Share Unit Plan consists of fully vested DSUs and RSUs, 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 the dividend. See "*Prior Sales*" for additional information with respect to the DSUs and RSUs issued pursuant to the Deferred and Restricted Share Unit Plan during the year ended December 31, 2023.

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
Robert A. King Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Rife	January 6, 2020
Lisa N. Farstad Alberta, Canada	Vice President, Corporate Services	Vice President, Corporate Services of Rife	March 1, 2020
Brianna E. C. Guenther Alberta, Canada	General Counsel and Corporate Secretary	General Counsel and Corporate Secretary of Rife	September 6, 2022
Ian C. Hantke Alberta, Canada	Vice President, Diversified Royalties	Vice President, Diversified Royalties of Rife	January 1, 2022
Susan J. Nagy Alberta, Canada	Vice President, Business Development	Vice President, Business Development of Rife	April 1, 2023
Colin Strem Alberta, Canada	Vice President, Asset Development	Vice President, Asset Development of Rife	November 1, 2023

As at February 28, 2024, the directors and executive officers of the Manager as a group beneficially owned, directly or indirectly, or exercised control or direction over 281,262 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.

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations that are in competition with 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 of Directors approval of potential acquisitions, dispositions, joint ventures, farm-in arrangements and transactions of a similar nature that involve Freehold and Rife and/or Canpar ("**Related Party Transactions**"). 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 Transactions that are outside the ordinary course of business or involve aggregate consideration over $1,000,000 be approved by members of the Board of Directors who do not have a material interest in such transaction.

To clarify the access to acquisition opportunities that are sourced by the Manager or Rife, effective March 1, 2021, Rife, Freehold, the Manager and Canpar entered into the Acquisitions Opportunities Agreement (which was amended and restated in May 2022) to complement the existing provisions in the Management Agreement. Under the terms of the Acquisitions Opportunities Agreement, Rife ensures that Freehold receives priority to consider acquisition opportunities for royalty interests in oil and gas properties. The Acquisitions Opportunities Agreement also sets out a framework that allows each of Freehold and Rife an opportunity to elect to participate in acquisition opportunities for royalty interests in alternative minerals (non-oil and gas) as well as non-resources with the percentage of each entities' right to participate dependent on whether the property relates to an existing property of Rife, Canpar or Freehold.

The Acquisition Opportunities Agreement also applies to other entities that are affiliates of Rife if Rife and/or the Manager provides management and/or operational services to such entities.

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 Canadian income tax filings for its 2015, 2018, 2019, 2021 and 2022 tax years have been assessed by the CRA to deny the deduction of $222 million in non-capital losses that were acquired through a 2015 business combination (the **"Assessments"**). Pursuant to the Assessments, denied non-capital losses claims resulted in taxes, interest, and penalties totaling an estimated $62 million.

Freehold has objected to the Assessments and has provided deposits totaling $31 million with taxation authorities as at February 28, 2024 (December 31, 2023 - $29 million). Freehold has received legal advice that it should be entitled to deduct the non-capital losses and as such, management is of the opinion that its tax filings to date were filed correctly and Freehold will succeed in its objection to the Assessments.

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.

CN Pension Trust Funds participated in the September 2021 Offering by purchasing 939,200 2021 Subscription Receipts at a price of $9.05 per 2021 Subscription Receipt for gross proceeds of approximately $8.5 million. See "*General Development of the Business – Year Ended December 31, 2021*".

The Manager and Rife are wholly-owned subsidiaries of the CN Pension Trust Funds, which held, directly or indirectly, 25,104,464 Common Shares as at February 28, 2024, representing approximately 16.66% 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 2023 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 and amended May 7, 2019, March 31, 2021, September 24, 2021 and October 21, 2022, 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 and Ryder Scott, 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 and Ryder Scott, 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.sedarplus.ca. 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 19, 2024, which relates to our Annual Meeting of Shareholders to be held on May 7, 2024. Additional financial information is provided in

Freehold's consolidated financial statements for the year ended December 31, 2023 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, 2023. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2023, 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, 2023, 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)			
			Audited ($000s)	Evaluated ($000s)	Reviewed ($000s)	Total ($000s)
Trimble Engineering Associates Ltd.	December 31, 2023	Canada	-	$930,326	-	$930,326
RSC Group, Inc.	December 31, 2023	United States	-	$838,447	-	$838,447
TOTALS			-	**$1,768,773**	-	**$1,768,773**

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.
Part of the Trimble Energy Group
(signed) "Stephen Trimble"
Stephen Trimble, P.Eng.
President and CEO
Calgary, Alberta, Canada

February 28, 2024

RSC Group, Inc.

(signed) "Andrew J. Thompson"
Andrew J. Thompson, P. Eng.

Calgary, Alberta, Canada

February 28, 2024

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.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators 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 evaluators;

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

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

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 evaluators on the reserves data; and

c. the content and filing of this report.

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

(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) "*J. Douglas Kay*"

J. Douglas Kay
Director and Member, Reserves Committee

DATED as of this 28 day of February, 2024.

APPENDIX C

Audit, Finance & Risk Committee Mandate

Role and Objective

The Audit, Finance and Risk 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;
5. to strengthen the role of the independent directors by facilitating in-depth discussions between directors on the Committee, management and the external auditors;
6. to promote Freehold's strong financial health; and
7. to assist the board with identification and management of risk.

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. At least one member of the Committee shall be a financial expert. Someone shall be considered a financial expert if they are or was a chief financial officer, chartered accountant, certified management accountant, fellow chartered accountant (FCA), fellow certified practicing accountant (FCPA), or partner of an accounting firm, or someone with an equivalent skillset in the determination of the Board.
3. The Board will have the power to appoint the Committee Chair.
4. 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(s) 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 key financial matters, including but not limited to those pertaining to foreign currency, interest rates, capital markets, debt and tax;

4. 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;

5. 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;

6. 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;

7. 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;
8. 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;
9. Review, on a quarterly basis, the risk management policies and procedures of Freehold, including with respect to hedging, litigation, cyber security and insurance, including D&O insurance.
10. Review and approve management's hiring policies regarding current and former partners and employees of the present and former external auditor;
11. 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.

12. 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**");
13. 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
14. 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; last amended July 28, 2023

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FREEHOLD ROYALTIES