ANNUAL INFORMATION FORM

DATED APRIL 23, 2025

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ABBREVIATIONS

Abbreviations

Oil and Natural Gas Liquids		Natural Gas	
bbl	Barrel	Mcf	thousand cubic feet
bbls	Barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
bbls/d	barrels per day	MMBTU	million British Thermal Units
NGLs	natural gas liquids	GJ	Gigajoule

Other

AECO	Alberta Energy Company benchmark for natural gas
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
boe	barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mcfe	thousand cubic feet of natural gas equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of boe, Mboe and boe/d is based on a boe conversion ratio of 6 Mcf:1 bbl and may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Unless otherwise indicated, all of the information provided in this Annual Information Form is as at December 31, 2024 and all references to "**dollars**" and "**$**" are to the currency of Canada.

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements and forward-looking information within the meaning of applicable securities legislation. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intend", "forecast", "plans", "guidance" and similar expressions is intended to identify forward-looking statements or information.

More particularly and without limitation, this Annual Information Form contains forward-looking statements and information relating to the following:

- the performance characteristics of the Corporation's oil, NGLs and natural gas properties;
- oil, NGLs and natural gas production levels;
- the size of the oil, NGLs and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future adjusted funds flow;

- future tax horizons of the Corporation;
- capital programs;
- debt levels;
- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs.

The forward-looking statements and information contained in this Annual Information Form are based on certain key expectations and assumptions made by the Corporation, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labour and services.

Although the Corporation believes that the expectations reflected in the forward-looking statements and information in this Annual Information Form are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, the imposition of tariffs and any associated reciprocal tariffs by the U.S. and Canadian governments on the import of goods from one country to the other, including on oil and natural gas, the imposition of any other form of tax, restriction, or prohibition on the import or export of products from one country to the other, including on oil and natural gas, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the foregoing list of factors and risks is not exhaustive.

The forward-looking statements and information contained in this Annual Information Form are made as of the date hereof and, unless so required by applicable law, the Corporation undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise. The forward-looking statements and information contained in this Annual Information Form are expressly qualified by this cautionary statement.

INCORPORATION AND ORGANIZATION

Coelacanth Energy Inc. (the "**Corporation**" or "**Coelacanth**") was incorporated under the *Business Corporations Act* (Alberta) ("**ABCA**") on March 24, 2022 as "2418573 Alberta Ltd." for the purpose of oil and natural gas production, exploration and acquisition in the Two Rivers area of the Montney resource trend in northeast British Columbia as a wholly-owned subsidiary of Leucrotta Exploration Inc. ("**Leucrotta**"). On April 12, 2022, Articles of Amendment were filed to change its name to "Coelacanth Energy Inc." Coelacanth does not have any subsidiaries.

In connection with a plan of arrangement involving Coelacanth, Leucrotta, Vermilion Energy Inc. ("**Vermilion**"), and the securityholders of Leucrotta that was completed on May 31, 2022 (the "**Arrangement**"), Leucrotta and Coelacanth entered into a conveyance agreement dated May 31, 2022 (the "**Conveyance Agreement**") whereby Leucrotta transferred approximately $45.1 million in cash, net of transaction costs, and certain oil and natural gas assets primarily located in the Two Rivers area of British Columbia (the "**Two Rivers Assets**") to Coelacanth.

The Corporation's head office is located at Suite 2110, 530 – 8th Avenue S.W., Calgary, Alberta, T2P 3S8, and its registered office is located at Suite 1600, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

Additional details regarding the Arrangement are provided under the heading "*Business of the Corporation – Relevant Three Year History*" below.

BUSINESS OF THE CORPORATION

General

The Corporation is a growth-oriented, exploration-focused oil and natural gas company. The Corporation's primary areas of focus are presently in the Two Rivers area of northeast British Columbia. As at December 31, 2024, the Corporation's oil and gas assets produced approximately 865 boe/d of oil, natural gas and NGLs and the Corporation owned approximately 153,700 gross (142,700 net) acres of land.

Relevant Three Year History

On March 28, 2022, Vermilion, Leucrotta and Coelacanth entered into an arrangement agreement, as amended April 25, 2022 and May 19, 2022, to provide for the Arrangement (the "**Arrangement Agreement**"). Pursuant to the Arrangement, holders of common shares in the capital of Leucrotta ("**Leucrotta Shares**") (other than Vermilion) ultimately received in exchange for each Leucrotta Share held, $1.73 in cash and one common share in the capital of Coelacanth (a "**Common Share**") pursuant to a series of transactions, which included the following steps:

(a) each outstanding Leucrotta Share held by a non-resident holder was transferred to 24255566 Alberta Ltd., a wholly-owned subsidiary of Vermilion (the "**Purchaser**"), for $1.73 in cash and the obligation of the Purchaser to deliver to such non-resident holder one Common Share (see (e) below);

(b) the share capital of Leucrotta was reorganized and each Leucrotta Share was exchanged for one Class A common share (a "**Leucrotta Class A Share**") of Leucrotta and one Class C preferred share (a "**Leucrotta Class C Preferred Share**") of Leucrotta;

(c) each Leucrotta Class C Preferred Share (other than those held by Vermilion) was transferred to Coelacanth for one Common Share;

(d) each Leucrotta Class A Share (other than those held by either Vermilion or the Purchaser) was transferred to the Purchaser for $1.73 in cash; and

(e) the Purchaser delivered to each non-resident holder one Common Share for each Leucrotta Share previously held.

Pursuant to the Arrangement, holders of warrants of Leucrotta, each entitling the holder thereof to acquire one Leucrotta Share at an exercise price of $1.00 until March 31, 2023 (the "**Leucrotta Warrants**"), ultimately received upon exercise of each Leucrotta Warrant held, $1.73 in cash (less the exercise price for each Leucrotta Warrant) and one Common Share. Additionally, holders of warrants of Leucrotta, each entitling the holder thereof to acquire one Leucrotta Share on a "flow-through" basis under the *Income Tax Act* (Canada) at an exercise price of $1.00 until June 22, 2024 (the "**Leucrotta Flow-Through Warrants**"), ultimately received in exchange for each Leucrotta Flow-Through Warrant held, $0.76 and one Common Share.

Pursuant to the Arrangement, all holders of Common Shares were entitled to receive 0.1917 of one Common Share purchase warrant (each whole warrant being an "**Arrangement Warrant**") for each Common Share held. On May 31, 2022, Coelacanth issued approximately 55.6 million Arrangement Warrants pursuant to the Arrangement. Each Arrangement Warrant entitled the holder thereof to acquire one Common Share, at an exercise price of $0.27 per share, at any time until 5:00 p.m. (Calgary time) on August 2, 2022. A total of approximately

54.2 million Arrangement Warrants were exercised for total gross proceeds of approximately $14.6 million and approximately 1.3 million Arrangement Warrants expired unexercised.

As a result of the Arrangement, Vermilion, directly or indirectly, paid aggregate cash consideration of approximately $485.0 million to the former holders of Leucrotta Shares (other than Vermilion) and approximately $1.4 million to the former holders of the Leucrotta Flow-Through Warrants and Coelacanth issued an aggregate of approximately 289,792,341 Common Shares and an aggregate of approximately 55,553,192 Arrangement Warrants to the former holders of Leucrotta Shares.

On May 31, 2022, pursuant to the Conveyance Agreement, Leucrotta transferred approximately $45.1 million in cash, net of transaction costs, and the Two Rivers Assets to Coelacanth. The consideration for the Two Rivers Assets was an amount of approximately $78.8 million that was satisfied by Coelacanth through the assumption by Coelacanth of certain liabilities and obligations of Leucrotta and through the issuance of a Class C Preferred share in the capital of Coelacanth (a "**Class C Preferred Share**") and Common Shares. Pursuant to the Conveyance Agreement, Coelacanth assumed and agreed to indemnify and save harmless Leucrotta in respect of all environmental liabilities related to the Two Rivers Assets.

On May 31, 2022, pursuant to the Arrangement Agreement, Coelacanth entered into an area of exclusion, non-competition and non-solicitation agreement (the "**Area of Exclusion Agreement**") with Vermilion and Robert Zakresky. The Area of Exclusion Agreement provides for, among other things, Vermilion (and its affiliates) being restricted from directly or indirectly competing with Coelacanth for a period of time in the certain geographic area outlined therein and Coelacanth and Robert Zakresky being restricted from directly or indirectly competing with Vermilion in the certain geographic area outlined therein.

On May 31, 2022, pursuant to the Arrangement Agreement, Vermilion and Coelacanth entered into an investor rights agreement (the "**Investor Rights Agreement**"). Pursuant to the Investor Rights Agreement, Coelacanth has, among other things, granted Vermilion a right to nominate a director of Coelacanth provided that Vermilion (together with its affiliates) holds at least 10% of the issued and outstanding Common Shares and granted Vermilion certain participation and anti-dilution rights provided that Vermilion (together with its affiliates) holds at least 5% of the issued and outstanding Common Shares. Pursuant to the terms and conditions of the Investor Rights Agreement, Vermilion has agreed, subject to certain conditions and exceptions, not to sell any Common Shares or any securities convertible into Common Shares held by Vermilion or any affiliate of Vermilion until May 31, 2023 without the prior written consent of Coelacanth, which consent shall not be unreasonably withheld. Following the expiration of the period that Vermilion has agreed to not sell its Common Shares or any securities convertible into Common Shares, Vermilion has also agreed that, for so long as Vermilion (together with its affiliates) holds at least 5% of the issued and outstanding Common Shares, it shall grant Coelacanth a right to seek potential purchasers for any proposed sale by Vermilion or its affiliates of greater than 5% of the aggregate Common Shares held by Vermilion and its affiliates.

On May 31, 2022, pursuant to the Arrangement, Coelacanth and Vermilion entered into a registration rights agreement (the "**Registration Rights Agreement**"). Pursuant to the Registration Rights Agreement, Coelacanth has granted Vermilion the right (the "**Demand Registration Right**") to require Coelacanth to qualify the distribution of: (i) any Common Shares beneficially owned by Vermilion and/or its affiliates, from time to time; and (ii) any Common Shares issuable to Vermilion and/or its affiliates on the conversion, exchange or exercise of any securities convertible into or exchangeable or exercisable for Common Shares beneficially owned by Vermilion and/or its affiliates, from time to time (collectively, the "**Registerable Securities**"), by filing a prospectus under applicable Canadian securities laws and taking such other steps as may be required to facilitate a secondary offering in Canada of all or any portion of the Registerable Securities held by Vermilion, provided that Vermilion (together with its affiliates) holds at least 5% of the issued and outstanding Common Shares. In addition, if Coelacanth proposes to make a distribution for its own account or the account of any other securityholders of Coelacanth, the Registration Rights Agreement provides Vermilion with the right to require Coelacanth to include the Registerable Securities held by Vermilion in the proposed distribution.

On May 31, 2022, pursuant to the Arrangement, Vermilion subscribed for 53,303,668 Common Shares pursuant to a non-brokered private placement at a price of $0.27 per Common Share for aggregate gross proceeds of $14,391,990.

On June 10, 2022, Coelacanth closed a non-brokered private placement of approximately 14.0 million units to certain officers, employees and directors of Coelacanth at a price of $0.27 per unit for total gross proceeds of approximately $3.8 million. Each unit was comprised of one Common Share and one Common Share purchase warrant (a "**Warrant**"). The Warrants are exercisable at a price of $0.27 per Common Share and expire on June 10, 2027.

Concurrently on June 10, 2022, Coelacanth closed a non-brokered private placement of approximately 13.8 million units ("**Flow-Through Units**") to certain officers, employees and directors of Coelacanth at a price of $0.27 per Flow-Through Unit for total gross proceeds of approximately $3.7 million. Each Flow-Through Unit was comprised of one Common Share issued on a "flow-through basis" in respect of Canadian development expenses ("**CDE**") under the *Income Tax Act* (Canada) (a "**Flow-Through Share**") and one Flow-Through Share purchase warrant (a "**Flow-Through Warrant**"). The Flow-Through Warrants were exercisable at a price of $0.27 per Flow-Through Share until March 31, 2023, following which the Flow-Through Warrants are exercisable at a price of $0.27 per Common Share until 5:00 p.m. (Calgary time) on June 10, 2027.

On November 15, 2023, Coelacanth closed a bought-deal public financing (the "**Prospectus Financing**") through a syndicate of underwriters. Pursuant to the Prospectus Financing, the Corporation issued 100 million units under a short form prospectus dated November 3, 2023 at a price of $0.80 per unit for aggregate gross proceeds of $80 million. Each unit sold in the Prospectus Financing was comprised of one Common Share and one-third of one (⅓) Warrant (each whole Warrant, a "**Prospectus Financing Warrant**"). Each Prospectus Financing Warrant entitles the holder to purchase one Common Share at an exercise price of $1.05 per Common Share and expire on November 15, 2024. During November 2024, the expiry date was extended to June 30, 2025.

On November 16, 2023, Coelacanth closed a non-brokered private placement to three employees of 1,875,000 units at a price of $0.80 per unit for aggregate proceeds of $1.5 million. Each unit was comprised of one Common Share and one Warrant, which Warrant entitles the holder to purchase one Common Share at a price of $0.80 per share and expires on November 16, 2028.

On October 4, 2024, the Company secured two revolving bank credit facilities for a total of $52.0 million from a Canadian chartered bank. The credit facilities are backed by reserves at Two Rivers West plus a $45.0 million letter of credit from a third party. The commitment from the third party is for a two-year term. During the term, Coelacanth expects that the lending value of producing reserves at Two Rivers East will allow for the credit facility to be renegotiated and the letter of credit to be returned.

The first credit facility is a $7.0 million revolving operating demand loan credit facility that bears interest at prime plus 3.0%. The undrawn portion of the credit facility is subject to a standby fee of 1.0%. Any outstanding letters of guarantee reduce the amount that can be borrowed under the credit facility and bear interest at 4.0%. During the year ended December 31, 2024, the Company redeemed $5.4 million of restricted cash deposit GIC's and issued letters of guarantee for the same amount under the revolving operating demand loan credit facility thereby reducing the amount available from $7.0 million to $1.6 million.

The second credit facility is a $45.0 million revolving operating demand loan that bears interest at prime plus 0.25%. The undrawn portion of the credit facility is subject to a standby fee of 0.125%. This credit facility is secured by a $45.0 million letter of credit from a third party. The letter of credit fee is 3.0% of the total $45.0 million face value of the letter of credit whether drawn or not for the first one-year term plus the period prior to the start of the first term. The first term starts the earlier of when drawn or December 31, 2024. The Company has the option to extend the term by an additional maximum one-year term for a fee of 6% of the drawn portion of the letter of credit that can be reduced at any time by repayment of the credit facility.

The credit facilities and letter of credit are secured by a $75.0 million fixed and floating charge debenture on the assets of the Company. The next review of the credit facilities by the bank is scheduled on or before June 30, 2025.

On March 3, 2025, the Company received $22.7 million from a mid-stream company to finance a pipeline connecting Coelacanth facilities to the mid-stream company's gathering system. The Company is required to repay the principal amount over a five-year period at an effective interest rate of 12.0%. See "*Material Contracts*" in this Annual Information Form for more information.

Strategy

The Corporation's business plan is to focus on sustainable and profitable per share growth in both cash flow from operations and net asset value. To accomplish this, the Corporation will focus on enhancing its asset base through land acquisitions, corporate acquisitions, property acquisitions, exploratory drilling and development drilling.

The Corporation will internally generate exploration and development opportunities possessing medium risk and multiple prospective productive zone potential with a prudent exposure to higher risk/reward prospects. The Corporation will maintain a balance between exploration, development and exploitation drilling, combined with acquisition opportunities that meet the Corporation's business parameters. To achieve sustainable and profitable growth, the Corporation will control the timing and costs of its projects wherever possible. Accordingly, the Corporation will seek to become the operator of its properties to the greatest extent possible. Further, to minimize competition within its geographic areas of interest, the Corporation will, after giving consideration to its risk profile, strive to maximize its working interest ownership in its properties. While the Corporation intends to have the skills and resources necessary to achieve its objectives, participation in exploration and development in the oil and natural gas industry has a number of inherent risks. See "*Risk Factors*" in this Annual Information Form.

In reviewing potential drilling or acquisition opportunities, the Corporation gives consideration to the following criteria:

(a) risk capital required to secure or evaluate the investment opportunity;

(b) the potential return on the project, if successful;

(c) the likelihood of success; and

(d) the risked return versus cost of capital.

In general, the Corporation will use a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure, in an attempt to generate sustainable high levels of profitable production and financial growth.

The Board may, in its discretion, approve acquisitions that do not conform to these guidelines based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

(a) world market forces, including the ability of the Organization of the Petroleum Exporting Countries ("**OPEC**") to set and maintain production levels and prices for crude oil;

(b) political conditions, including the risk of hostilities in the Middle East, Eastern Europe and other regions throughout the world;

(c) increases or decreases in crude oil quality and market differentials;

(d) the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by the Corporation for its crude oil and natural gas;

(e) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;

(f) global and domestic economic and weather conditions;

(g) price and availability of alternative fuels; and

(h) the effect of energy conservation measures and government regulations.

Revenue Sources and Revenue

For the year ended December 31, 2024, approximately 79.2% of the revenue from the Corporation's properties before royalties was derived from tight oil and NGLs and approximately 20.8% was derived from shale gas. Production is sold to marketers at delivery points in or close to the producing field. The products produced and sold by the Corporation are tight oil, shale gas, and NGLs. Most of these products are sold on a short-term basis at prices that are a function of current market prices. None of the Corporation's products are sold to non-arm's length parties. The following table sets forth the aggregate sales of the products produced by the Corporation during the years ended December 31, 2024 and 2023:

Product Type	2024 Revenue ($000s)	2023 Revenue ($000s)
Shale Gas	2,852	1,933
Tight Oil	9,391	4,280
NGLs	1,493	450
Total	13,736	6,663

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation will actively compete for capital, skilled personnel, undeveloped land, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a worldwide basis and as such have greater and more diverse resources on which to draw on. See "*Risk Factors – Competition*" in this Annual Information Form.

Specialized Skill and Knowledge

The Corporation's business requires the application of technical skill in the areas of geology, geophysics and reservoir engineering, well drilling and completions and well production operations. The Corporation has assembled a team of skilled technical experts who provide the technical skills required to succeed in its business. See "*Risk Factors – Reliance on Operators and Key Employees*" in this Annual Information Form.

Seasonal Factors

The exploration for and development of oil and natural gas reserves in the Corporation's focus area is dependent on access to areas where operational activities are to be conducted. Seasonal weather variations, including freeze-up and break-up can delay such access. See "*Risk Factors – Seasonality*" in this Annual Information Form.

Environmental Protection

The oil and gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. The Corporation carefully monitors such legislation and makes the required expenditures necessary to remain in compliance. See "*Risk Factors – Environmental Concerns*" and "*Information Concerning Oil and Natural Gas Industry – Environmental Regulation*" in this Annual Information Form.

Personnel

As at December 31, 2024, the Corporation had 13 employees and 5 contract workers. As at the date hereof, the Corporation has 13 employees and 5 contract workers.

Environmental Policy

The Corporation is committed to managing and operating in a safe, efficient, environmentally responsible manner in association with its industry partners and is committed to continually improving its environmental, health, safety and social performance. To satisfy this commitment, the Corporation's operating practices and procedures are consistent with the requirements established for the oil and gas industry. Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resource protection and liability management (including site assessment and remediation). These practices and procedures apply to the Corporation's employees and the Corporation monitors all activities and makes reasonable efforts to ensure that companies who provide services to the Corporation will operate in a manner consistent with the Corporation's environmental policy.

The Corporation believes that it meets all existing environmental standards and regulations and includes sufficient amounts in its capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore, it is not anticipated that the Corporation's competitive position within the industry will be adversely affected by changes in applicable legislation. The Corporation completes due diligence reviews (to assess environmental liabilities and regulatory compliance) prior to proceeding with new acquisitions and developments.

The Corporation's environmental management plan and operating guidelines focus on minimizing the environmental impact of its operations while meeting regulatory requirements and corporate standards. The Corporation's environmental program includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a spill prevention, response and clean-up program; a fugitive emission survey and repair program; and an environmental liability assessment program.

The Corporation expects to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2024, expenditures for normal compliance with environmental regulations were approximately $1.4 million. The Corporation anticipates its expenditures for compliance with environmental regulations to be approximately $2.1 million in 2025.

The Corporation participates in both the Canadian federal and provincial regulated greenhouse gas emissions reporting programs and continues to quantify annual greenhouse gas emissions for internal reporting purposes. The Corporation is committed to mitigating its environmental impact through monitoring metrics, identifying areas of improvement and implementing new processes and procedures for key environmental consideration areas.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

This statement of reserves data and other information (the "**Statement**") is dated April 23, 2025 and is effective December 31, 2024. The preparation date of the information regarding reserves in the Statement and of the independent engineering evaluation of the Corporation's reserves (the "**GLJ Report**") prepared by GLJ Ltd. ("**GLJ**"), an independently qualified reserves evaluator and auditor of Calgary, Alberta, is March 19, 2025.

The future net revenue numbers presented throughout the Statement, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value.

Oil and Natural Gas Reserves

The following reserves data and associated tables summarize the reserves of crude oil, natural gas and associated products and the estimated present worth of future net cash flows associated with the Corporation's reserves as evaluated by GLJ. The reserves are based on forecast price assumptions. The information in respect of the reserves was derived from the GLJ Report, which report was prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") and the reserves definitions contained in National Instrument 51-101 – *Standard of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and the COGE Handbook.

The tables summarize the data contained in the GLJ Report and, as a result, may contain slightly different numbers than the GLJ Report due to rounding. The values in the GLJ Report do not include the value of undeveloped land holdings nor the tangible value of the Corporation's interest in any associated plant and wellsite facilities. The cash flow forecasts account for downhole well abandonment costs and reclamation of wells that are assigned reserves. **It should not be assumed that the present values of estimated future net cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. Actual crude oil, natural gas and NGLs reserves may be greater than or less than the estimates provided herein.**

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.

All of the reserves held by the Corporation as at December 31, 2024 were located in Canada and, specifically, in the province of British Columbia.

The following tables detail the aggregate gross and net reserves of the Corporation, as at December 31, 2024, using forecast prices and costs as well as the aggregate net present value of future net revenue attributable to the reserves estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Summary of Oil and Gas Reserves
Forecast Prices and Costs
As at December 31, 2024

	Tight Oil		Shale Gas		NGLs		Total Oil Equivalent	
Reserves Category	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED								
Developed Producing	344	280	8,097	6,460	150	105	1,843	1,461
Developed Non-Producing	1,874	1,512	38,862	33,975	720	550	9,071	7,725
Undeveloped	1,137	858	27,324	23,868	506	374	6,197	5,210
TOTAL PROVED	3,355	2,650	74,283	64,303	1,376	1,029	17,111	14,396
PROBABLE	2,154	1,607	44,543	38,444	825	603	10,403	8,618
TOTAL PROVED PLUS PROBABLE	5,509	4,257	118,826	102,747	2,201	1,632	27,515	23,014

Net Present Values of Future Net Revenues
Forecast Prices and Costs
As at December 31, 2024

Reserves Category	Before Income Taxes Discounted At (% /year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	After Income Taxes Discounted At (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% (1) ($/boe)	($/mcfe)
PROVED												
Developed Producing	21,615	17,655	14,827	12,765	11,220	21,615	17,655	14,827	12,765	11,220	10.15	1.69
Developed Non-Producing	131,346	97,179	74,105	57,825	45,878	131,346	97,179	74,105	57,825	45,878	9.59	1.60
Undeveloped	93,068	63,389	44,903	32,689	24,196	93,068	63,389	44,903	32,689	24,196	8.62	1.44
TOTAL PROVED	246,030	178,224	133,834	103,279	81,294	246,030	178,224	133,834	103,279	81,294	9.30	1.55
PROBABLE	221,362	147,285	105,806	80,431	63,701	164,310	114,153	85,304	67,088	54,658	12.28	2.05
TOTAL PROVED PLUS PROBABLE	467,391	325,509	239,640	183,710	144,995	410,340	292,377	219,138	170,366	135,952	10.41	1.74

Notes:
(1) Unit values are based on the Corporation's net reserves.
(2) Columns may not add due to rounding.

The following tables provide a breakdown of various elements of future net revenue attributable to proved reserves and proved plus probable reserves estimated using forecast prices and costs, calculated without discount:

Total Future Net Revenue
(Undiscounted)
Forecast Prices and Costs
As at December 31, 2024

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)	($000s)
Proved	681,865	115,655	210,319	106,585	3,276	246,030	-	246,030
Proved Plus Probable	1,139,864	207,374	312,245	148,276	4,578	467,391	57,052	410,340

The following tables detail by product type the net present value of future net revenue (before deducting future income tax expenses), estimated using forecast prices and costs, calculated using a discount rate of 10%:

Future Net Revenue By Product Type
Forecast Prices And Costs
As at December 31, 2024

Reserves Category	Product Type	Future Net Revenue Before Income Taxes(2) (discounted at 10%/year) ($000s)	($/boe)	($/mcfe)
Proved	Tight Oil(1)	133,834	9.30	1.55
	Total	133,834	9.30	1.55
Proved Plus Probable	Tight Oil(1)	239,640	10.41	1.74
	Total	239,640	10.41	1.74

Notes:
(1) Including solution gas and other by-products.
(2) Other Corporation revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on the Corporation's net reserves.

Pricing Assumptions

The following tables detail the reference prices as at January 1, 2025 in the GLJ Report for evaluating the net present values of future net revenues from reserves relating to the Corporation's reserves disclosed above. The forecast cost and price assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating and capital costs. GLJ is an independent qualified reserves evaluator and auditor.

Summary of Pricing and Inflation Rate Assumptions as at January 1, 2025
Forecast Prices and Costs

	OIL		NATURAL GAS		LIQUIDS				
Year	WTI Crude Oil @ Cushing, Oklahoma ($USD/bbl)	MSW, Light Crude Oil @ Edmonton 40° API ($CAD/bbl)	AECO/NIT Spot ($CAD/ Mmbtu)	Midwest @ Chicago Spot ($USD/ Mmbtu)	Condensate Edmonton ($CAD/bbl)	Butane Edmonton ($CAD/bbl)	Propane Edmonton ($CAD/bbl)	Spec Ethane ($CAD/bbl)	Exchange Rate ($USD/$CAD)
Forecast									
2025	71.25	91.33	2.05	2.79	102.96	54.80	36.53	6.09	0.7050
2026	73.50	93.32	3.00	3.70	99.93	48.99	32.66	9.35	0.7300
2027	76.00	96.45	3.50	4.01	100.65	50.63	33.76	11.07	0.7500
2028	78.53	99.82	4.00	4.10	104.12	52.41	34.94	12.78	0.7500
2029	80.10	101.80	4.08	4.18	106.20	53.45	35.63	13.04	0.7500
2030	81.70	103.84	4.16	4.27	108.27	54.52	36.34	13.32	0.7500
2031	83.34	105.92	4.24	4.35	110.45	55.61	37.07	13.60	0.7500
2032	85.00	108.04	4.33	4.45	112.67	56.72	37.81	13.89	0.7500
2033	86.70	110.20	4.41	4.54	114.93	57.86	38.57	14.19	0.7500
2034	88.44	112.40	4.50	4.63	117.25	59.01	39.34	14.49	0.7500
Thereafter +	……………………………………………………Escalated at a rate of 2.0%………………………………………………………………								0.7500

Note:
(1) Weighted average historical prices of the Corporation's reserves for the period ended December 31, 2024 were $2.14/Mcf for natural gas and $83.99/bbl for crude oil and NGLs.

Reconciliations of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's gross proved reserves, gross probable reserves and gross proved plus probable reserves as at December 31, 2024 against such reserves as at December 31, 2023 based on forecast price and cost assumptions.

	Tight Oil			Natural Gas Liquids		
	Total Proved Reserves (Mbbls)	Probable Reserves (Mbbls)	Total Proved Plus Probable (Mbbls)	Total Proved Reserves (Mbbls)	Probable Reserves (Mbbls)	Total Proved Plus Probable (Mbbls)
December 31, 2023	2,291	746	3,038	720	250	970
Extensions and Improved Recovery	1,212	1,387	2,599	509	535	1,043
Technical Revisions	(28)	18	(9)	173	40	213
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(15)	3	(13)	(1)	1	-
Production	(105)	-	(105)	(24)	-	(24)
December 31, 2024 [(1)]	3,355	2,154	5,509	1,376	825	2,201

	Tight Oil			Natural Gas Liquids		
	Total Proved Reserves	Probable Reserves	Total Proved Plus Probable	Total Proved Reserves	Probable Reserves	Total Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)

	Shale Gas			Total boe		
	Total Proved Reserves	Probable Reserves	Total Proved Plus Probable	Total Proved Reserves	Probable Reserves	Total Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(Mboe)	(Mboe)	(Mboe)
December 31, 2023	44,784	15,647	60,432	10,475	3,604	14,080
Extensions and Improved Recovery	27,468	28,862	56,330	6,298	6,732	13,031
Technical Revisions	3,663	71	3,734	756	70	825
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(297)	(37)	(334)	(66)	(3)	(69)
Production	(1,335)	-	(1,335)	(352)	-	(352)
December 31, 2024 (1)	74,283	44,543	118,826	17,111	10,403	27,515

Note:
(1) Columns may not add due to rounding.

Undeveloped Reserves

The following table sets forth, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the periods indicated:

Company Gross Reserves First Attributed by Year

Proved Undeveloped Reserves

	Shale Gas (MMcf)		Natural Gas Liquids (Mbbls)		Tight Oil (Mbbls)		Oil Equivalent (Mboes)	
	First Attributed(1)	Total at Year-end	First Attributed(1)	Total at Year-end	First Attributed(1)	Total at Year-end	First Attributed(1)	Total at Year-end
2022	3,732	7,620	64	130	103	349	789	1,749
2023	10,860	15,260	176	245	562	694	2,548	3,483
2024	22,112	27,324	410	506	974	1,137	5,069	6,197

Note:
(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

Probable Undeveloped Reserves

	Shale Gas (MMcf)		Natural Gas Liquids (Mbbls)		Tight Oil (Mbbls)		Oil Equivalent (Mboes)	
	First Attributed(1)	Total at Year-end	First Attributed(1)	Total at Year-end	First Attributed(1)	Total at Year-end	First Attributed(1)	Total at Year-end
2022	9,198	10,309	157	176	429	512	2,119	2,406
2023	2,299	8,883	37	141	143	331	563	1,953
2024	27,453	33,722	509	625	1,310	1,485	6,394	7,730

Note:
(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

The proved and probable undeveloped reserves attributable to the Corporation's reserves have been estimated by GLJ in the GLJ Report in accordance with the procedures and standards contained in the COGE Handbook and consistent with NI 51-101.

The Corporation's undeveloped reserves are primarily found in the Montney area of northeast British Columbia.

Approximately 100% of the proved undeveloped reserves and 100% of the proved plus probable undeveloped reserves are scheduled to be developed within the next three years. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (accelerated depletion or facility constraints); (iii) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; (iv) changing allocation of capital due to success in new areas or horizons; and (v) acquisitions or dispositions. See "*Risk Factors*" in this Annual Information Form.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserves estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative. See "*Risk Factors*" in this Annual Information Form.

The reserves estimates contained herein are based on current production forecasts, prices and economic conditions. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

The evaluated oil and natural gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in an oil and natural gas producing company.

Future Development Costs

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

	Forecast Prices and Costs	
Year	Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
2025	95,633	127,818
2026	-	-
2027	9,396	18,902
2028	-	-
2029	-	-
2030	-	-
2031	883	883
2032	-	-
2033	-	-
2034	-	-
2035	-	-
Remainder	672	672
Total: Undiscounted	106,585	148,276
Total: Discounted at 10% per year	99,275	136,436

The Corporation expects that the capital listed in the preceding table will be funded through its existing working capital (including cash balance), credit facilities, expected cash flow from operations, new equity issues (if available on favourable terms), and debt financing (if available and when appropriate).

For the first year of the economic forecast, the Corporation expects to fund the estimated future development costs through its existing working capital (including cash balance) and expected cash flow from operations.

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

Principal Properties

Information relating to the Corporation's principal properties is set out below.

Two Rivers, British Columbia

The Corporation holds an average 93% working interest in 103,700 gross (96,000 net) acres of land in the Two Rivers area of northeastern British Columbia with rights in the main targeted zone of the Montney formation. Production for the fourth quarter of 2024 was approximately 1,084 boe/d from the Montney formation. The Corporation plans to drill 8 (8.0 net) horizontal wells in the Montney formation in British Columbia during 2025.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2024 in which the Corporation has a working interest and which are producing or non-producing. All of these wells are onshore and located in British Columbia. The stated interests are subject to land-owners' and other royalties, where applicable, in addition to the customary Crown royalties and mineral taxes.

	Oil Wells(3)				Natural Gas Wells(4)			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
British Columbia	4	4.0	12	11.8	-	-	-	-
Total(5)	4	4.0	12	11.8	-	-	-	-

Notes:
(1) "Gross" refers to all oil and gas wells in which the Corporation has a working interest.
(2) "Net" refers to the aggregate of the percentage working interests of the Corporation in the gross wells, before the deduction of any royalty interests.
(3) Includes light and medium oil wells and tight oil wells.
(4) Includes conventional natural gas wells and shale gas wells.
(5) Total well count differs from well count provided in our discussion of abandonment and reclamation costs below, as this table excludes abandoned, water source, water injection, and disposal wells.

For additional information respecting the Corporation's important properties, plants, installations and facilities and the reserves attributed to each property and production information included therein, see "*Principal Properties*" above.

Land Holdings including Properties with No Attributed Reserves

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
British Columbia	8,960	8,960	119,340	108,440	128,300	117,400
Alberta	-	-	25,300	25,300	25,300	25,300
Total	8,960	8,960	144,640	133,740	153,600	142,700

Notes:
(1) "Gross" refers to the total number of acres in which the Corporation holds an interest.
(2) "Net" refers to the aggregate of the percentage working interests of the Corporation in the gross acres.

The undeveloped land holdings attributable to the Corporation's reserves, as at December 31, 2024, did not consist of any undeveloped land. Booked reserves of the Corporation have been focused in and around existing developed land and therefore all of the undeveloped land is currently unbooked.

As at December 31, 2024, none of the Corporation's land holdings are expected to expire in 2025. Future expiring acreage is continuously being evaluated and attempts will be made to maintain the Corporation's rights on the acreage and mitigate expiries through land swaps, asset dispositions or drilling to maintain the lease. The Corporation has no material work commitments currently scheduled on these lands other than certain abandonment and reclamation costs on non-core properties and non-Montney zones.

No third party evaluation of the undeveloped lands included in the Corporation's land holdings has been undertaken.

Forward Contracts

Other than as disclosed in the Corporation's financial statements as at and for the year ended December 31, 2024, the Corporation does not have any future material commitments to buy, sell, exchange or transport oil or natural gas.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment costs for downhole well abandonments which are expected to be incurred in connection with the Corporation's reserves for the periods indicated. The amounts disclosed are based on forecast prices and costs for total proved plus probable reserves.

	Downhole Well Abandonment and Reclamation Costs ($000s)	Downhole Well Abandonment and Reclamation Costs Discounted at 10% ($000s)
Total as at December 31, 2024	4,578	352
Anticipated to be paid in 2025	-	-
Anticipated to be paid in 2026	-	-
Anticipated to be paid in 2027	-	-
Anticipated to be paid in 2028	122	83
Total anticipated costs in next four years	122	83

The portion of abandonment and reclamation costs not deducted as abandonment and reclamation costs in estimating future net revenue is $12.1 million ($4.6 million discounted at 10%). Salvage value recoveries on wells and facilities of $1.0 million ($0.1 million discounted at 10%) have also been excluded from future net revenues. The Corporation's abandonment and reclamation costs and salvage values were estimated by management and employees of the Corporation based on their experience in the industry.

Provisions for the abandonment and reclamation of all of the Corporation's existing and future wells to a standard imposed by applicable government or regulatory authorities have been included in GLJ's forecast of well abandonment and reclamation costs (this includes all active entities within active assets only); all other abandonment and reclamation costs have not been included (including but not limited to wells for which no reserves are assigned and for facilities and pipelines). See Note 9 of the Corporation's financial statements for the years ended December 31, 2024 and 2023, available on SEDAR+ at www.sedarplus.com, for full disclosure of the Corporation's decommissioning obligations.

As at December 31, 2024, the Corporation is expected to incur reclamation and abandonment costs in respect of 84 (71.6 net) wells.

Tax Horizon

Based on after tax economic forecasts prepared by GLJ, income taxes are not payable by the Corporation in respect of the Corporation's total proved reserves and are payable in 2030 in the total proved plus probable reserves category.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses), property acquisition expenditures incurred, and property disposition proceeds received by the Corporation for the year ended December 31, 2024.

Expenditures	Year Ended December 31, 2024 ($000s)
Exploration costs(1)	83,291
Development costs(2)	1,206
Property acquisitions – unproved properties(3)	-
Total	84,497

Notes:

(1) Geological and geophysical capital expenditures and drilling and completion costs for wells that have been determined by management of the Corporation to be exploration and evaluation assets ("**E&E**") in accordance to the Corporation's financial statements.

(2) Drilling and completion costs and facilities and pipeline capital expenditures that have been determined by management of the Corporation to be property, plant and equipment ("**PP&E**") in accordance to the Corporation's financial statements.

(3) Includes property acquisitions and Crown land acquisitions.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells drilled during the period ended December 31, 2024.

	Year Ended December 31, 2024			
	Exploratory Wells(1)		Development Wells(2)	
	Gross(3)	Net(4)	Gross(3)	Net(4)
Oil	4	4.0	0	0.0
Gas	0	0.0	0	0.0
Service	1	1.0	0	0.0
Dry	0	0.0	0	0.0
Total	5	5.0	0	0.0

Notes:

(1) Wells that have been determined by management of the Corporation to be E&E assets in accordance to the Corporation's financial statements.

(2) Wells that have been determined by management of the Corporation to be PP&E in accordance to the Corporation's financial statements.

(3) "Gross" means the total number of wells comprising the Corporation's reserves.

(4) "Net" means the number of wells obtained by aggregating the working interest in each of the gross wells comprising the Corporation's reserves.

During the year ended December 31, 2024, the Corporation drilled three Lower Montney wells at its 5-19 pad at Two Rivers East, drilled a water disposal well at its battery location at Two Rivers East, and drilled a land retention well on its Two Rivers West lands.

For details on the important current and likely exploration and development activities during 2025, see "*Principal Properties*" in this Annual Information Form.

Production History

The following table sets forth certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback in respect of the Corporation's reserves for the periods indicated.

	Three Months March 31, 2024	Three Months June 30, 2024	Three Months September 30, 2024	Three Months December 31, 2024	Year-to-Date December 31, 2024
Average Daily Production [1]					
Tight Oil (bbl/d)	281	228	188	451	287
Shale Gas (Mcf/d)	3,934	3,724	3,450	3,490	3,648
Natural Gas Liquids (bbl/d)	56	95	65	51	67
Combined (boe/d)	993	944	829	1,084	962
Average Price Received					
Tight Oil ($/bbl)	85.46	98.41	90.39	86.70	89.31
Shale Gas ($/Mcf)	3.40	1.55	1.41	2.07	2.14
Natural Gas Liquids ($/bbl)	51.51	69.40	58.32	59.64	61.07
Combined ($/boe)	40.57	36.85	30.99	45.57	39.01
Royalties Paid [2]					
Tight Oil ($/bbl)	22.72	24.48	16.78	17.58	20.06
Shale Gas ($/Mcf)	0.51	0.09	0.06	0.13	0.21
Natural Gas Liquids ($/bbl)	11.01	15.96	11.88	10.38	12.86
Combined ($/boe)	9.08	7.86	5.02	8.22	7.66
Operating Expenses [3][4]					
Tight Oil ($/bbl)	9.89	10.38	10.07	8.51	9.47
Shale Gas ($/Mcf)	1.65	1.72	1.68	1.25	1.58
Natural Gas Liquids ($/bbl)	9.89	10.24	10.07	6.81	9.47
Combined ($/boe)	9.89	10.34	10.07	7.88	9.47
Transportation Expenses					
Tight Oil ($/bbl)	2.92	2.93	3.15	6.15	4.24
Shale Gas ($/Mcf)	0.68	0.72	0.76	0.76	0.73
Natural Gas Liquids ($/bbl)	0.07	0.09	0.10	0.12	0.10
Combined ($/boe)	3.54	3.55	3.91	5.01	4.04
Netback Received [5]					
Tight Oil ($/bbl)	49.93	60.62	60.39	54.46	55.54
Shale Gas ($/Mcf)	0.56	(0.98)	(1.09)	(0.07)	(0.38)
Natural Gas Liquids ($/bbl)	30.54	43.11	36.27	42.33	38.64
Combined ($/boe)	18.06	15.10	11.99	24.46	17.84

Notes:

(1) Before deduction of royalties.

(2) Quarterly royalty amounts are based on estimates and are subject to periodic adjustments. These adjustments can cause significant variations when applied to low production volumes and expressed on a per barrel basis.

(3) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between tight oil, shale gas and NGLs production.

(4) Where multiple product types are attributable to a single well, the operating expenses attributable to that well are allocated based on the proportionate production of each product. Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(5) Netbacks are calculated by subtracting royalties, operating expenses and transportation expenses from revenues.

The following table indicates the net average daily production volumes from the Corporation's important fields for the year ended December 31, 2024.

	Tight Oil (bbl/d)	**Shale Gas (Mcf/d)**	**Natural Gas Liquids (bbl/d)**	**Boe (boe/d)**
Two Rivers	287	3,648	67	962
Other properties	-	-	-	-
Total	287	3,648	67	962

Production Estimates

The following table sets out the estimated volume of the Corporation's gross production for the year ending December 31, 2025 as reflected in the estimates of future net revenue disclosed herein. [(1)]

	Tight Oil (bbls/d)	Shale Gas (Mcf/d)	NGLs (bbls/d)	Oil Equivalent (boe/d)
Proved				
Two Rivers	1,598	21,980	407	5,668
Other properties	-	-	-	-
Total Proved	1,598	21,980	407	5,668
Probable				
Two Rivers	376	4,031	75	1,123
Other properties	-	-	-	-
Total Probable	376	4,031	75	1,123
Proved Plus Probable				
Two Rivers	1,974	26,011	482	6,791
Other properties	-	-	-	-
Total Proved Plus Probable	1,974	26,011	482	6,791

Note:

(1) Columns may not add due to rounding.

Marketing

Crude oil, natural gas and NGLs will be priced based on daily spot prices adjusted for quality and transportation. See "*Forward Contracts*" in this Annual Information Form.

DEFINITIONS, NOTES AND OTHER CAUTIONARY STATEMENTS

In the tables set forth in "Statement of Reserves Data and Other Oil and Gas Information" and elsewhere in this Annual Information Form, unless otherwise indicated, the following definitions and other notes are applicable.

1. "**Gross**" means:

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

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

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

2. "**Net**" means:

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

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

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

3. Definitions of Reserves:

Reserves Categories

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

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

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

Development and Production Status

Each of the reserves categories (proved, probable and possible) 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, possible) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

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

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

- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;

- at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative 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.

4. Future Income Tax Expense

Future income tax expenses are estimated:

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

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

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

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

5. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines to the extent necessary in developing the reserves;

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

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

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

9. "**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.

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented do not represent fair market value.

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

DIRECTORS AND OFFICERS OF THE CORPORATION

The name, municipality of residence and principal occupation for the last five years of each of the directors and executive officers of the Corporation are as follows:

Name and Municipality of Residence	Office[(7)]	Principal Occupation	Director Since[(8)]
Robert Zakresky Calgary, Alberta Canada	President, Chief Executive Officer and Director	Mr. Zakresky obtained his Bachelor of Commerce from the University of Saskatchewan in 1988. He obtained his Chartered Accountant designation with PriceWaterhouseCoopers in 1990. Mr. Zakresky has held the position of President and Chief Executive Officer ("**CEO**") of the Corporation since March 24, 2022. From June 2014 until May 2022, Mr. Zakresky was the President, CEO and a director of Leucrotta. From 1993 to August 2014, Mr. Zakresky has sequentially held the position of President, CEO and a director of Bellator Exploration Inc., Viracocha Energy Inc. ("**Viracocha**"), Chamaelo Energy Inc. ("**CEI**"), Chamaelo Exploration Ltd. ("**CEL**") and Crocotta Energy Inc. ("**Crocotta**"), all of which were Calgary based oil and gas exploration and production companies.	March 24, 2022
Bret Kimpton Calgary, Alberta Canada	Vice President Operations and Chief Operating Officer	Mr. Kimpton has held the position of Vice President Operations since September 6, 2022. From May 2015 to December 2021, Mr. Kimpton was the Vice President Production and from September 2010 to May 2015 was the Production Manager of Storm Resources Ltd. From January 2005 to September 2010, Mr. Kimpton was the Senior Operations Engineer at Storm Exploration Inc. Mr. Kimpton graduated from the University of Calgary in 1999 with a degree in Chemical Engineering with a minor in Petroleum Engineering and is a registered Professional Engineer in the Province of Alberta.	N/A
Nolan Chicoine Calgary, Alberta Canada	Vice President Finance and Chief Financial Officer	Mr. Chicoine completed his Bachelor of Commerce (Accounting, 1999) and his Masters of Professional Accounting (2000) from the University of Saskatchewan. In 2002 he obtained his Chartered Accountant designation with KPMG LLP. Mr. Chicoine has held the position of Vice President Finance and Chief Financial Officer ("**CFO**") of the Corporation since March 24, 2022. From June 2014 until May 2022, Mr. Chicoine was the Vice President Finance and CFO of Leucrotta which traded on the TSXV. From November 2006 until August 2014, Mr. Chicoine was the Vice President Finance and CFO of Crocotta. From January 2006 to October 2006, he was Vice President Finance and CFO of CEL and from June 2005 to January 2006, he was Vice President Finance and CFO of CEI, both of which traded on the TSX. Mr. Chicoine held the position of Controller of CEI from April 2004 to June 2005 and from January 2003 to April 2004, Mr. Chicoine was the Controller of Viracocha. Prior thereto Mr. Chicoine was a Senior Accountant with KPMG LLP.	N/A
John Fur Calgary, Alberta Canada	Vice President Geosciences	Mr. Fur obtained his Bachelor of Science, Geophysics from the University of Calgary in 1989. Mr. Fur has held the position of Vice President Geosciences of the Corporation since May 30, 2022. From August 2014 until May 2022, Mr. Fur was the Manager, Exploration of Leucrotta. From 1990 to 2014 Mr. Fur has sequentially held the position of Sr. Geophysicist with Husky Oil, Amber Energy Inc., Post Energy Corp., Canadian Natural Resources Ltd, Viracocha, CEI, CEL, and Crocotta.	N/A

Name and Municipality of Residence	Office[7]	Principal Occupation	Director Since[8]
Jody Denis Calgary, Alberta Canada	Vice President Drilling and Completions	Mr. Denis has held the position of Vice President of Drilling & Completions since July 18, 2023. From October 2021 to July 2023, Mr. Denis was the Drilling Engineering and Operations Manager of the Corporation and its predecessor, Leucrotta. From August 2019 to July 2021, Mr. Denis was a Senior Operations Advisor at BlackSwan Energy Ltd. Previous to this Mr. Denis held manager and executive positions with various intermediate and junior energy companies. Mr. Denis graduated from the University of Saskatchewan in 2001 with a degree in Chemical Engineering and is a registered Professional Engineer in the Provinces of Alberta and British Columbia.	N/A
Gregory Peterson Calgary, Alberta Canada	Corporate Secretary	Mr. Peterson is a partner with Gowling WLG (Canada) LLP, a multinational law firm. Mr. Peterson has held the position of Corporate Secretary of the Corporation since March 24, 2022. Mr. Peterson has been a prior director and the corporate secretary of many public companies, private companies and sports associations.	N/A
William Lancaster[2][3][5][6][9] Denver, Colorado USA	Director	Mr. Lancaster is currently the President and a Director of GMT Exploration Company LLC ("**GMT Exploration**"), positions he has held since April 2001 and January 2005, respectively. Prior thereto, Mr. Lancaster held position of Vice President Exploration and Production at GMT Exploration from January 2000 to April 2001. Mr. Lancaster graduated from the University of Colorado with a bachelor's degree in Geologic Engineering in 1978. Mr. Lancaster is a former president of the Colorado Oil and Gas Association, was formerly on the Board of Directors of Pipestone Energy Corp., and is a member of the Rocky Mountain Association of Geologist, and the American Association of Petroleum Geologist.	May 31, 2022
John Brussa[1][3][4] Calgary, Alberta Canada	Director	Mr. Brussa holds a Bachelor of Arts, History and Economics degree and a Bachelor of Laws degree. Mr. Brussa is the Chairman of Burnet, Duckworth & Palmer LLP, a Calgary-based energy law firm where he focuses on tax law. He is also a director of a number of energy and energy-related companies. Mr. Brussa is a past governor of the Canadian Tax Foundation and is a past Jarislowsky Fellow at the Haskayne School of Business at the University of Calgary.	May 31, 2022
Tom Medvedic[1][3][5] Calgary, Alberta Canada	Director	Mr. Medvedic obtained his Bachelor of Commerce from the University of Calgary in 1989. He obtained his Chartered Accountant (Alberta Institute) designation with PriceWaterhouseCoopers in 1993. Mr. Medvedic is currently the Chief Financial Officer of NorthRiver Midstream Inc. Prior thereto, Mr. Medvedic served as the President, Canadian Division of Calfrac Well Services Ltd. ("**Calfrac**") from 2015 to 2019. Previous to that, Mr. Medvedic served as the Senior Vice President, Corporate Development of Calfrac since November 2008. Mr. Medvedic also served as Senior Vice President and Chief Financial Officer of Calfrac from July 2004 to November 2008.	May 31, 2022
Raymond T. Hyer[1][2][4] Belleair Shore, Florida USA	Director	Mr. Hyer is a Certified Public Accountant ("**CPA**") and was a senior partner of Raymond T. Hyer & Company, a CPA firm founded by his late father, until his retirement in 1990. Mr. Hyer then became President, CEO and Chairman of Gardner-Gibson, Inc. ("**Gardner-Gibson**") and remained in these positions until his retirement in 2017. Mr. Hyer also served as Chairman of the board of directors of Sun Paints & Coatings, Inc. ("**Sun Coatings**") for over 35 years. In late 2020 both Sun Coatings and Gardner-Gibson were sold to strategic buyers. Mr. Hyer continues to remain the Chairman of the board of directors of Rowell Chemical Corp. which operates in the midwest region of the United States. Mr. Hyer has been a long time investor in various aspects of the oil industry and has diversified knowledge of the industry and the operations and workings of various companies. Mr. Hyer also devotes time to charitable organizations in the Tampa area. Mr. Hyer is a graduate of the College of The Holy Cross in Worcester, Massachusetts and received his Masters in Business Administration from Long Island University	May 31, 2022

Name and Municipality of Residence	Office[7]	Principal Occupation	Director Since[8]
Harvey Doerr[2][4][5][6] Calgary, Alberta Canada	Director	Mr. Doerr has more than 29 years of full-time experience in the oil and gas industry, including broad exposure to domestic and international exploration and production, heavy oil and oilsands, offshore, refining, retail marketing, acquisitions and divestitures, strategic planning and government relations. He was previously Executive Vice President of Murphy Oil Corporation ("**Murphy Oil**"), responsible for worldwide refining and marketing operations and strategic planning. Prior thereto, Mr. Doerr held various positions in the upstream oil and gas industry with Murphy Oil and affiliates, primarily in Canada. Since his retirement from Murphy Oil in 2009, Mr. Doerr has continued his career as a professional director, serving on the boards of directors of a number of public, private and not-for-profit corporations. Mr. Doerr earned a Bachelor of Science in Mechanical Engineering from the University of Alberta (1981). Mr. Doerr is a Professional Engineer, has completed the Advanced Management Program at Harvard Business School and holds the ICD.D designation from the Institute of Corporate Directors.	May 31, 2022

Notes:

(1) Member of the Audit Committee of the Corporation. See "*Audit Committee*" in this Annual Information Form.

(2) Member of the Reserves Committee of the Corporation.

(3) Member of the Compensation Committee of the Corporation.

(4) Member of the Corporate Governance Committee of the Corporation.

(5) Member of the Health, Safety and Environment (HSE) Committee of the Corporation.

(6) Member of the Environmental, Social and Governance (ESG) Committee of the Corporation.

(7) As at April 16, 2024, the directors and executive officers of the Corporation, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 68,833,362 Common Shares, constituting approximately 13.0% of the issued and outstanding Common Shares.

(8) Each director's term expires at the close of the next annual meeting of the shareholders of the Corporation, unless re-elected.

(9) Mr. Lancaster is the President and a Director of GMT Exploration which holds 17,315,022 Common Shares (representing approximately 3.3% of the issued and outstanding Common Shares). GMT Capital Corp. holds 128,748,109 Common Shares (representing approximately 24.2% of the issued and outstanding Common Shares). According to the Form 62-103F3 filed by GMT Capital Corp. pursuant to National Instrument 62-103 – *The Early Warning System and Related Take-Over Bid and Insider Reporting Issues* and dated June 10, 2022, GMT Capital Corp. specifically disclaims any ownership or control over the Common Shares held by GMT Exploration and confirms that there is no agreement, commitment or understanding between GMT Capital Corp. and GMT Exploration with regards to the acquisition or disposition of, or the exercise of any of the voting or exercise rights attaching to, any of the Common Shares. Mr. Lancaster exercises control and direction the Common Shares held by GMT Exploration.

Orders

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

Bankruptcies

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

Mr. Brussa was a director of Enseco Energy Services Corp. ("**Enseco**"), a public oilfield service company, which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Mr. Brussa resigned as a director of Enseco on October 14, 2015. On December 21, 2015 Enseco was assigned into bankruptcy by the receiver.

Mr. Brussa was a director of Argent Energy Ltd. which was the administrator of Argent Energy Trust. On February 17, 2016, Argent Energy Trust and its Canadian and United States holding companies (collectively "**Argent**") commenced proceedings under the CCAA for a stay of proceedings until March 19, 2016. On the same date, Argent filed voluntary petitions for relief under Chapter 15 of the United States Bankruptcy Code ("**Chapter 15**"). On March 9, 2016, the stay of proceedings under the CCAA was extended until May 17, 2016. Additionally on March 10, 2016 the U.S. Bankruptcy Court approved an order recognizing the CCAA as the foreign main proceedings under Chapter 15. Mr. Brussa resigned on June 30, 2016.

Mr. Brussa resigned as a director of Twin Butte Energy Ltd. ("**Twin Butte**") on September 1, 2016. On September 1, 2016, the senior lenders of Twin Butte (the "**Senior Lenders**") made an application to the Court to appoint a receiver and manager over the assets, undertakings and property of Twin Butte under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Twin Butte was suspended by the TSX. On September 1, 2016, the Senior Lenders were granted a receivership order by the Court.

Mr. Brussa and Mr. Zakresky were both a director of Virginia Hills Oil Corp. ("**VHO**"), a TSXV listed oil and gas company. On February 13, 2017, VHO received a demand notice and notice of intention to enforce security from its lenders and agreed to consent to the early enforcement of the lenders' security and the appointment of a receiver over all of the current and future assets, undertakings and properties of VHO. The receiver was appointed on February 13, 2017. Mr. Brussa and Mr. Zakresky both resigned as a director of VHO on February 24, 2017.

Mr. Peterson was formerly a director of Great Prairie Energy Services Corp. ("**GPE**") (a public oilfield service company) which was placed in receivership on January 22, 2016. Mr. Peterson resigned as a director of GPE in connection with the appointment of the receiver on January 22, 2016.

From July 8, 2010 to February 20, 2018, Mr. Peterson was a director of Manitok Energy Inc. ("**Manitok**"), a company listed on the TSX Venture Exchange. On January 10, 2018, Manitok announced that it had filed a Notice of an Intention to Make a Proposal (the "**NOI**") pursuant to the provisions of the *Bankruptcy and Insolvency Act* (Canada), naming FTI Consulting Canada Inc. ("**FTI**") as the proposed trustee. Manitok was unable to form a proposal with its creditors within 30 days after filing its NOI and as a result, on February 20, 2018, the Court issued a Receivership Order placing Manitok into receivership and substituting Alvarez & Marsal Canada Inc. ("**Alvarez**") in place of FTI as the trustee in bankruptcy. The Court also appointed Alvarez as the receiver and manager of Manitok and terminated the NOI. All of the directors of Manitok, including Mr. Peterson, resigned.

Penalties and Sanctions

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

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial or director positions with other oil and natural gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Certain of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation.

AUDIT COMMITTEE

The purpose of the Corporation's audit committee is to provide assistance to the Board in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation and its subsidiaries. It is the objective of the audit committee to maintain a free and open means of communications among the Board, the independent auditors and the senior management of the Corporation.

The full text of the audit committee's charter is attached hereto as Appendix "C" and forms part of this Annual Information Form.

Composition of the Audit Committee

The audit committee is comprised of Tom Medvedic, John Brussa and Raymond T. Hyer. Tom Medvedic is the chairman of the audit committee. Each of the members is independent within the meaning of section 1.4 of National Instrument 52-110 *Audit Committees* ("**NI 52-110**") and each of the members is financially literate within the meaning of section 1.6 of NI 52-110.

Relevant Education and Experience

Please refer to the individual biographies for the members of the audit committee above under the heading "Directors and Officers of the Corporation".

Pre-Approval Policies and Procedures

The audit committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence.

External Auditor Service Fees (By Category)

Year Ended	Audit Fees[1]	Audit Related Fees	Tax Fees	All Other Fees
December 31, 2024	$229,950	$nil	$nil	$nil
December 31, 2023	$246,100	$nil	$nil	$nil

Note:

(1) Fees include audit of financial statements, review of interim financial statements and services provided in connection with statutory and regulatory filings or engagements.

DESCRIPTION OF SHARE CAPITAL

The authorized capital of the Corporation consists of an unlimited number of Common Shares, an unlimited number of non-voting common shares (the "**Non-Voting Shares**"), an unlimited number of class A preferred shares, issuable in series (the "**Class A Preferred Shares**"), an unlimited number of class B preferred shares, issuable in series (the "**Class B Preferred Shares**"), and an unlimited number of Class C Preferred Shares, of which, as at the date of this Annual Information Form, 532,901,907 Common Shares and nil Non-Voting Shares, Class A Preferred Shares, Class B Preferred Shares, and Class C Preferred Shares are issued and outstanding. The Corporation's Articles have been filed on SEDAR+ at www.sedarplus.com.

Common Shares

Holders of Common Shares are entitled to: (a) one vote per Common Share at all meetings of shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board, as a class equally with the holders of the Non-Voting Shares, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Common Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, share rateably, together with the holders of Non-Voting Shares and of shares of any other class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution. Holders of not less than 4% of the issued and outstanding Common Shares may requisition the Board to call a meeting of shareholders for the purposes stated in the requisition.

Non-Voting Shares

Holders of Non-Voting Shares shall be entitled to: (a) receive notice of and to attend any meeting of the shareholders of the Corporation provided that, except as required by law, the holders of the Non-Voting Shares shall not be entitled to vote at any meeting of the shareholders; (b) receive dividends if, as and when declared by the Board on the Non-Voting Shares as a class equally with the holders of the Common Shares, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares ranking in priority to the Non-Voting Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Non-Voting Shares in respect of return of capital on dissolution, share rateably, together with the holders of Common Shares and of shares of any other class of shares of the Corporation ranking equally with the Non-Voting Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Class A Preferred Shares

Prior to the issuance thereof, the Board shall fix the designation, rights, privileges, restrictions and conditions attaching to each series of Class A Preferred Shares including, without limiting the generality of the foregoing, the amount, if any, specified as being payable preferentially to such series on a distribution of capital of the Corporation; the extent, if any, of further participation in a distribution of capital; voting rights, if any; and dividend rights (including whether such dividends be preferential, or cumulative or non-cumulative), if any. In the event of the liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, holders of each series of Class A Preferred Shares shall be entitled, in priority to holders of Common Shares, Non-Voting Shares and Class B Preferred Shares on a distribution of capital, to be paid rateably with holders of each other series of Class A Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series on a distribution of capital of the Corporation. Holders of each series of Class A Preferred Shares shall be entitled, in priority to holders of Common Shares, Non-Voting Shares and Class B Preferred Shares, to be paid rateably with holders of each other series of Class A Preferred Shares, the amount of cumulative dividends, if any, specified as being payable preferentially to holders of such series.

Class B Preferred Shares

Prior to the issuance thereof, the Board shall fix the designation, rights, privileges, restrictions and conditions attaching to each series of Class B Preferred Shares including, without limiting the generality of the foregoing, the amount, if any, specified as being payable preferentially to such series on a distribution of capital of the Corporation; the extent, if any, of further participation in a distribution of capital; voting rights, if any; and dividend rights (including whether such dividends be preferential, or cumulative or non cumulative), if any. In the event of the liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, holders of each series of Class B Preferred Shares shall be entitled, in priority to holders of Common Shares and Non-Voting Shares, to be paid rateably with holders of each other series of Class B Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series on a distribution of capital of the Corporation. Holders of each series of Class B Preferred Shares shall be entitled, in priority to holders of Common Shares and Non-Voting Shares, to be paid rateably with holders of each other series of Class B Preferred Shares, the amount of cumulative dividends, if any, specified as being payable preferentially to holders of such series.

Class C Preferred Shares

Prior to the issuance thereof, the Board shall fix the redemption amount of each Class C Preferred Share (the "**Redemption Amount**"). Except as otherwise required by law, the holders of Class C Preferred Shares shall not be entitled to receive notice of, to attend at, or to vote at meetings of the shareholders of the Corporation. The holders of the Class C Preferred Shares shall be entitled to receive and the Corporation shall pay thereon, as and when declared by the directors of the Corporation out of the monies of the Corporation properly available for the payment of dividends, dividends in such amount and in such form as the directors of the Corporation may from time to time determine and all dividends which the directors of the Corporation may declare on the Class C Preferred Shares shall be declared and paid in equal amounts per share on all Class C Preferred Shares at the time outstanding. In the event of the dissolution, liquidation or winding-up of the Corporation or other distribution of assets of the Corporation among its shareholders for the purpose of winding-up its affairs or upon a reduction of capital, the holders of the Class C Preferred Shares shall be entitled to receive the Redemption Amount, plus any declared and unpaid dividends, per Class C Preferred Share before any assets of the Corporation shall be distributed to the holders of the Common Shares, Non-Voting Shares, Class A Preferred Shares and Class B Preferred Shares. After payment of the amount so payable to them, the holders of the Class C Preferred Shares shall not be entitled to share in any further distribution of the assets of the Corporation. The Corporation may redeem at any time the whole or from time to time part of any Class C Preferred Shares then outstanding on payment of the Redemption Amount, plus any declared and unpaid dividends, for each such share to be redeemed. Any holder of Class C Preferred Shares may, at the holder's option, at any time, upon giving notice, require the Corporation to redeem at any time the whole or from time to time any part of the Class C Preferred Shares held by the holder by payment of the Redemption Amount, plus any declared and unpaid dividends, for each share to be redeemed.

DIVIDENDS

The Corporation has not declared or paid any dividends on the Common Shares, the Non-Voting Shares, the Class A Preferred Shares, the Class B Preferred Shares, or the Class C Preferred Shares. Any decision to pay dividends on such shares in the future will be made by its Board on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. It is the current intention of the Corporation not to pay any dividends in the near future.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares have been listed and posted for trading on the TSXV since June 20, 2022 under the trading symbol "CEI". The following table sets out the price range for, and trading volume of, the Common Shares as reported by the TSXV for the periods indicated:

	Trading Price		Volume Traded
	High	Low	# of shares
January 2024	$0.77	$0.68	1,333,761
February 2024	$0.84	$0.67	14,605,184
March 2024	$0.83	$0.74	1,563,308
April 2024	$0.87	$0.75	2,203,819
May 2024	$0.82	$0.76	601,688
June 2024	$0.81	$0.73	1,366,800
July 2024	$0.79	$0.73	1,062,139
August 2024	$0.91	$0.70	1,730,379
September 2024	$0.81	$0.76	2,090,120
October 2024	$0.83	$0.73	1,326,649
November 2024	$0.80	$0.69	1,041,394
December 2024	$0.94	$0.74	3,432,152
January 2025	$0.89	$0.76	3,562,096
February 2025	$0.95	$0.81	3,941,446
March 2025	$0.87	$0.80	2,756,109
April 1-23, 2025	$0.91	$0.78	1,429,155

Prior Sales of Unlisted Securities

The following table summarizes the issuance by the Corporation of Common Shares from treasury or securities convertible into Common Shares in the twelve-month period prior to December 31, 2024:

Date of Issuance	Type of Security Issued	Number of Securities Issued	Exercise Price
January 22, 2024	restricted share units ("**RSU**")(1)	100,000	N/A
January 22, 2024	options(2)	250,000	$0.70
March 15, 2024	RSUs(1)	2,588,483	N/A
March 15, 2024	options(2)	5,236,967	$0.80
November 19, 2024	RSUs(1)	100,000	N/A
November 19, 2024	options(2)	200,000	$0.70

(1) RSUs vest and become exercisable into Common Shares on a 1:1 basis as to 1/3 on every anniversary following the date of grant.

(2) Options vest and become exercisable into Common Shares on a 1:1 basis as to 1/3 on every anniversary following the date of grant.

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Companies operating in the oil and natural gas industry are subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry. It is not expected that any of such controls or regulations would affect the operations of the Corporation in a manner materially different than they would affect other companies of similar size in the oil and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing

Oil

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

Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the Canada Energy Regulator (the "**CER**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the CER and the issuance of such a licence requires a public hearing and the approval of the Governor in Council. The CER is currently undergoing a consultation process to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012. In this transitory period, the CER has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

In Canada, the price of natural gas results from transactions between buyers and sellers in an open, transparent market environment. Natural gas exported from Canada is subject to regulation by the CER and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that export contracts in excess of two years must continue to meet certain criteria prescribed by the CER and the Government of Canada. As is the case with oil, natural gas exports for a term of less than two years must be made pursuant to a CER order, or, in the case of exports for a longer duration, pursuant to a CER licence and Governor in Council approval. The price received by the Corporation will depend, in part, on the prices of competing natural gas and other substitute fuels, natural gas quality, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply/demand balance and other contractual terms of sale.

The Government of British Columbia also regulates the volume of natural gas which may be removed from the province for consumption elsewhere based on such factors as availability of reserves, transportation arrangements and market considerations.

NGLs

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

Transportation Constraints and Market Access

Under the Canadian Constitution, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the *Canadian Energy Regulator Act* (the "**CERA**"), new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines also require approvals from several levels of government in the United States.

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.

Natural gas prices in Western Canada have been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which is generally lower than the prices received in other markets.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the *United Nations Declaration of the Rights of Indigenous Peoples* ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**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* (the "**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.

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 the 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, but has confirmed that the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act. 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.

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 infringed the BRFN's rights guaranteed under Treaty 8. Going forward, the Blueberry Decision may have significant impacts on the regulation of industrial activities in northeast British Columbia, including Treaty 8 lands where a substantial portion of the Corporation's land will be situated. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties.

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 crude oil and natural gas development, and a new planning regime for future crude oil and natural gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on crude oil and natural gas revenue sharing and provincial royalty revenue-sharing in the next two fiscal years. The BRFN Agreement now serves as a blueprint for other agreements between the Government of British Columbia and First Nations 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. The long-term impacts and risks of the Blueberry Decision on the Canadian oil and natural gas industry remain uncertain. See "*Risk Factors – Indigenous Land and Rights Claims*" in this Annual Information Form.

International Trade Agreements

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

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

Canada is also party to CETA, which provides for duty-free, quota-free European Union market access for Canadian crude oil and natural gas products. Following the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada entered into the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"), which replicates CETA on a bilateral basis to maintain the status quo of the Canada-United Kingdom trade relationship.

While it is uncertain what effect CETA, CUKTCA or any other trade agreements will have on the petroleum and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, NGLs, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties owed to the freehold owner. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

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

Additionally, the federal government may from time to time provide incentives to the oil and gas industry. In November 2018, the federal government announced its plans to implement an accelerated investment incentive that will provide oil and gas businesses with eligible CDE and Canadian oil and gas property expenses ("**COGPE**") a first year deduction that is 150% of the 30% or 10% deduction, respectively, that would normally be available for CDE or COGPE expenses incurred before 2024 and 125% for expenses incurred between 2023 and before 2028. The federal government also announced in late 2018 that it will make $1.6 billion available to the oil and gas industry in light of worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for oil and gas projects related to economic diversification as well as direct funding for clean growth oil and gas projects.

British Columbia

<u>*Crown Royalties*</u>

On October 7, 2021, the Government of British Columbia launched a comprehensive review of its oil and gas royalty system. The new oil and gas royalty system (the "**New Framework**") was announced in May 2022. The New Framework increases the minimum royalty rate from 3% to 5%, and eliminates the Deep Well, Marginal Well, Ultra-marginal Well, Low Productivity Well Rate Reduction, and Clean Growth Infrastructure royalty programs (the "**Old Royalty Programs**"). New wells drilled under the New Framework will pay the flat royalty of 5% until capital spent on drilling and completions is recovered, at which point they will move to a price-sensitive royalty rate between 5% and 40%, depending on the specific commodity being produced.

Wells drilled on or after September 1, 2022 are not eligible to qualify for the Old Royalty Programs, and will pay a 5% royalty rate for the equivalent of the first 12 months of production. Following this period, these wells will pay the prevailing price-sensitive royalty rates until September 1, 2024 when all wells will be transitioned to the New Framework. Wells drilled prior to September 1, 2022 will pay royalties based on the current framework until September 1, 2024, at which time those wells will be transitioned to the New Framework and will no longer be able to take advantage of the Old Royalty Programs.

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

Freehold Royalties and Taxes

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

For oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax to the Government of British Columbia.

Land Tenure

Mineral Rights

The Province of British Columbia owns most of the mineral rights to the oil and natural gas located within its 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. The provincial government in British Columbia conducts regular land sales where oil and natural gas companies bid for leases to explore for and produce oil and natural gas pursuant to mineral rights owned by the provincial government. These leases generally have a fixed term; however, a lease may be continued beyond its initial term if the necessary conditions are satisfied.

The Province of British Columbia has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a disposition. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

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

Surface Rights

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

Liability Management Rating Programs

British Columbia

In British Columbia, the British Columbia Energy Regulator (the "**BCER**") oversees the Liability Management Rating Program (the "**BC LMR Program**") and the new Permittee Capability Assessment program (the "**BC PCA Program**") to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. The BC PCA Program was established as a result of the Comprehensive Liability Management Plan released by the BCER in May 2019 (the "**BC CLM Plan**"). The objectives of the BC CLM Plan are ensuring that the cost of reclaiming oil and gas sites continued to be paid for by industry rather than the province's residents, protecting public safety and safeguarding the environment. The BCER is in the process of replacing the BC LMR Program with the BC PCA Program. Prior to the BC PCA Program becoming effective on April 1, 2022, the BCER would determine the required security deposits for permit holders under the *Oil and Gas Activities Act* (British Columbia) (the "**OGAA**") in accordance with the BC LMR Program. The BC LMR Program is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., a liability management rating below 1.0) were considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

The BCER has recently begun transitioning from the BC LMR Program towards a more holistic assessment under the new BC PCA Program. The BC PCA Program will primarily be used to determine security deposits required of permit holders, and includes an evaluation of more than only a permittee's ratio of liabilities to assets, but will also assess a permittee's financial capabilities and various aspects of their operations.

In the spring of 2018, a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. The OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The OGAA permits the BCER to impose more than one levy in a given calendar year.

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

The Government of British Columbia passed amendments to the OGAA under the *Miscellaneous Statutes Amendment Act (No.2)* in October 2021. These amendments allow the BCER to grant exemptions for strict compliance with the requirements of the Dormancy Regulation. In turn, this may mean that a permit holder can, with approval, depart from the regulated timelines set under the Dormancy Regulation. The relevant amendments which provide the BCER with the power to grant these exemptions came into force on October 28, 2021.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's oil and gas industry in response to the pandemic caused by SARS-CoV 2 ("**COVID-19**"), in May 2020 the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta and British Columbia. These funds were administered by regulatory authorities in each province and disbursed through various provincial programs. The majority of these funds have now been allocated and disbursed.

Environmental Regulation

The Canadian oil and natural gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition, 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 "**CO_2e**"), may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

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.

The CERA and the *Impact Assessment Act* (Canada) (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the Impact Assessment Agency of Canada (the "**IA Agency**") or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75km of new right of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process.

In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The Court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

British Columbia

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

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

In November 2022, the Government of British Columbia passed the *Energy Statutes Amendment Act, 2022*, changing the name of the 'British Columbia Oil and Gas Commission' (the "**BCOGC**") to the 'British Columbia Energy Regulator' and expanding its mandate to include oversight of hydrogen, ammonia, and methanol. In support of the government's stated desire to transition away from fossil fuels and grow the province's hydrogen industry, the OGAA will also be renamed the *Energy Resources Activities Act* (the "**ERAA**"). In addition to expanding the BCER's jurisdiction to include hydrogen, ammonia, and methanol, the updated ERAA will also expand director and officer responsibility for costs associated with orphan sites.

In May 2018, the BCOGC (as the BCER was then known) issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). The BCOGC introduced enhancements to the Special Project Order in April 2021. Boundaries within the Kiskatinaw Area were reduced, while technical requirements were increased. Permit holders in the Kiskatinaw Area are subject to additional requirements before and after conducting hydraulic fracturing operations, including: (1) developing a seismic monitoring and mitigation plan that is submitted to the BCOGC; (2) notifying the BCOGC and local residents about planned hydraulic fracturing operations; and (3) submitting to the BCOGC a report respecting monitoring of hydraulic fracturing operations after the conclusion of hydraulic fracturing operations. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BCOGC on demand. If a seismic event occurs, permit holders are subject to a defined reporting system that sets thresholds on the Richter scale of seismic magnitude and obliges permit holders to employ mitigation practices in the event of seismicity above those thresholds. The obligations range from reporting the seismic event and developing an approved protocol to mitigate against subsequent seismicity, to initiating such protocols, to suspending operations until permitted to resume by the BCOGC. Under the enhanced Special Project Order, a magnitude 3.0 or above seismic event will result in the immediate suspension of fracturing activities from the suspected well(s) for a minimum of five calendar days. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. These requirements are outlined in provincial legislation, namely the *Water Sustainability Act* and the *Dam Safety Regulation*. Despite these regulatory requirements, a number of unlicensed dams have been identified throughout northeastern British Columbia that have been constructed without the requisite regulatory authorizations. The BCER has issued compliance orders with respect to individual dams, but it remains uncertain how and to what extent the relevant industry regulators will respond to this issue. The Corporation may face operational delays depending on the level of severity with which regulatory authorities decide to address these unauthorized projects, particularly where the Corporation is not strictly complying with the current regulatory framework.

An updated *Environmental Assessment Act* came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act*, the Government of British Columbia enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the British Columbia Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and natural gas industry in Canada. 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.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the convention 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 in Glasgow, Scotland, Canada made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

In line with the Canada's pledge to impose a cap on emissions from the oil and gas sector, the federal government published a discussion paper on July 18, 2022 that outlines two potential regulatory options for such a cap. Those proposed options are either to: (i) implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. These options are currently under review and interested parties had the opportunity to make submissions regarding the proposed cap, ending in September 2022. 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 (the "**Climate Change Framework**") in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. The Climate Change Framework provided for a carbon pricing strategy, with a carbon tax starting at $10 per tonne, increasing annually until it reaches $50 per tonne in 2022. 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 ("**OBPS**") for large industry (enabled by the *Output-Based Pricing System Regulations*) and a fuel charge (enabled by the *Fuel Charge Regulations*), both of which impose a price on CO_2e emissions. The GGPPA system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure 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 reaches a maximum price of $50/tonne of CO_2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO_2e will increase by $15 per year until it reaches $170/tonne of CO_2e in 2030. Effective January 1, 2023, the minimum price permissible under the GGPPA rose to $85/tonne of CO_2e.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In the Saskatchewan and Ontario references, the appellate Courts found the GGPPA to be constitutional; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the Supreme Court of Canada and on March 25, 2021, the Supreme Court of Canada found that the federal government has the constitutional authority to enact the GGPPA.

On June 8, 2022, the *Greenhouse Gas Offset Credit System Regulations* (Canada) 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 *Clean Fuel Regulations* (Canada) (the "**Clean Fuel Regulations**") came into force and in July 2023 they took effect. The Clean Fuel Regulations replaced the former *Renewable Fuels Regulation* (Canada), and aims to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives. The Clean Fuel Regulations impose obligations on primary suppliers of transportation fuels in Canada and require 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 emissions 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 collected 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 form of emissions cap on the oil and gas sector and the overall effect of such a cap remain uncertain.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

To meet international commitments to reducing global methane emissions, the federal government released proposed amendments to the Federal Methane Regulations in December 2023. The proposed amendments build on the existing requirements and would apply to upstream, midstream and transmission onshore oil and gas facilities with a view to reducing methane emissions by at least 75% in the oil and gas sector by 2030, relative to 2012 levels. The new requirements would include reducing volatile organic compound emissions as further described under Schedule 1 of the *Canadian Environmental Protection Act, 1999*. The amendments would prohibit intentional venting of hydrocarbon gas and require physical connection to conservation or destruction equipment. Some exemptions to such venting prohibition would apply, such as during planned equipment maintenance or to carry out certain activities that prevent prolonged interruption of gas supply to the public. Intentional emissions associated with combustion and flaring of hydrocarbon gas would require meeting stringent requirements for continued operation. The amendments would also address unintentional emissions by introducing a risk-based approach to monitoring oil and gas facilities. The risk-based approach would implement inspection schedules based on the type of oil and gas facilities designated as either more likely (Type 1) or less likely (Type 2) to emit methane. If unintentional emissions are detected, the amendments would also impose timelines to conduct repairs to remediate those unintentional emissions; the repair timelines would vary depending on the emission rate detected.

The proposed amendments are targeted to come into force in January 2027. The federal government intends to stagger the implementation of the proposed regulatory measures, with full sector compliance by 2030. The federal government may introduce changes to the proposed amendments following further consultations with stakeholders and the provinces. The current Federal Methane Regulations do not apply in Alberta, British Columbia or Saskatchewan. The regulations in each province have equivalent processes to the federal measures aimed at reducing methane emissions and each has entered into equivalency agreements with the federal government. These equivalency agreements are set to expire before January 2027, which will require new equivalency agreements to be entered into, to ensure continued non-application of the Federal Methane Regulations.

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

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced a $750 million Emissions Reduction Fund ("**ERF**") intended to support pollution reduction initiatives, including methane and other GHG emissions. Funds disbursed through the ERF will primarily take the form of repayable contributions to onshore and offshore oil and gas firms. Of the $750 million in funding, $675 million was allocated to the Onshore Deployment Program, while $75 million was dedicated to the Offshore Deployment Program and the Offshore RD&D (research, development and demonstration) Program.

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 is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures CO_2 from facilities, including industrial or power applications, or directly from the atmosphere. The captured CO_2 is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. The federal government has indicated that urgent steps are necessary 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 are considering amending Canadian reporting requirements to include the new international standards, however to what extent they will be adopted remains unclear.

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

British Columbia

In August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge increased on April 1, 2022 from $40/tonne of CO_2e to $50/tonne of CO_2e and will continue to increase in line with the GGPPA minimum charge. Federal carbon pricing mechanisms are not currently in force in British Columbia, as the province's programs currently meet or exceed the federal benchmark stringency requirements.

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

On December 5, 2018, the British Columbia provincial government announced an updated clean energy plan, "**CleanBC**", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of oil and natural gas production; (v) eliminating methane emissions associated with natural gas production by 2035; and (vi) incentivizing the adoption of zero-emissions vehicles. Complementing its CleanBC plan, on March 26, 2021, the Government of British Columbia announced a number of sector-specific emissions reduction targets, established with reference to 2007 emissions levels, that it aims to achieve by 2030, including reduction targets of 27-32% for the transportation sector, 38-43% for industry and 33-38% for oil and gas.

The Government of British Columbia established the CleanBC Industry Fund in 2019 to support clean industry development in the province. The fund uses a portion of carbon tax revenue paid by large emitters to invest in projects aimed at reducing greenhouse gas emissions. In spring 2024, the CleanBC Industry Fund will launch a call for proposals, which will include four funding streams: Emissions Performance, Innovation Accelerator, Feasibility Studies, and Industrial Electrification.

In October 2021, the Government of British Columbia announced a more ambitious climate change plan called the CleanBC Roadmap to 2030 (the "**CleanBC Roadmap**"), aimed at helping British Columbia achieve its 2030 emission reduction targets established under the CleanBC plan. The CleanBC Roadmap includes plans for, among other things, laws requiring 90% of new passenger vehicles sold in the province to be zero-emission by 2030, all new buildings to be zero-carbon beginning in 2030, the electrification of public transit and ferries, and for increased support for clean hydrogen and negative emissions technology. Further, the CleanBC Roadmap plans to increase carbon taxation in the province to meet or exceed the federal GGPPA benchmark.

In January 2020, the BCOGC (as the BCER was then named) implemented a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. A further amendment was made in 2023 to put more concrete parameters around suspension of inactive facilities. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia.

In 2008, British Columbia enacted the Carbon Tax Act, which introduced a tax on consumed fuels, and in 2019, the CleanBC Industrial Incentive Program ("**CIIP**") came into effect, which introduced an additional carbon pricing system for large industry. The CIIP aims to encourage cleaner operations by reducing carbon tax costs for certain low-emitting facilities. On April 1, 2024, British Columbia will begin transitioning to a new output-based pricing system ("**BC OBPS**"), which will eventually replace the CIIP, with elements of both the CIIP and BC OBPS remaining in place until the end of 2024. The BC OBPS will be mandatory for large emitters that emit over 10,000 tons of carbon dioxide equivalent annually. Given the evolving nature of climate change policy, including carbon taxes, it is expected that current and future climate change regulations will increase the Corporation's operating expenses, and, in the long-term could impact the demand for oil and natural gas and related products.

RISK FACTORS

The holding of securities in the Corporation should be considered highly speculative due to the nature of the Corporation's business and the present stage of its development. The following is a summary of certain risk factors relating to the activities of the Corporation and the ownership of the Corporation's securities which should be carefully considered before making an investment decision relating to the Corporation's securities.

Risks Relating to the Corporation and its Assets

Volatility of Oil and Gas Prices and Markets

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, trade wars, and conflicts in the Middle East and Eastern Europe. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See "*Information Concerning the Oil and Natural Gas Industry – Transportation Constraints and Marketing*" in this Annual Information Form.

The Corporation's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on the Corporation's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of the Corporation, including, but not limited to, the world economy and OPEC's ability to adjust supply to world demand, government regulation, the availability of alternative fuel sources, political stability or other economic or political developments. In particular, conflict and political uncertainty also continues to progress in the Middle East, including the ongoing military conflict in Israel, the West Bank and Gaza Strip, Yemen and the Red Sea. To the extent that certain political actions taken in North America, Europe, the Middle East and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, costs for goods and services required for the Corporation's business could increase and access to skilled labour could decrease, negatively impacting the Corporation's business, financial condition, results of operations, prospects and the market value of its Common Shares, which negative impact could prove to be material over time. See "*International Conflict*" below.

Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources. In addition, the marketability of the production depends upon the availability and capacity of gathering systems and pipelines and the effect of federal and provincial regulation on such production and general economic conditions. All of these factors are beyond the control of the Corporation.

Fluctuations in the price of commodities and associated price differentials affect the value of the Corporation's assets and the Corporation's ability to pursue its business objectives. Prolonged periods of commodity price depression and volatility may also affect the Corporation's ability to meet guidance targets and its financial obligations as they come due. Any substantial and extended decline in the price of oil and gas could have an adverse effect on the Corporation's reserves, borrowing capacity, revenues, profitability and funds flow and may have a material adverse effect on the Corporation's business, financial condition, results of operations, prospects and the level of expenditures for the development of oil and natural gas reserves. This may include delay or cancellation of existing or future drilling or development programs or curtailment in production as the economics of producing from some wells may become impaired.

If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying amount of the Corporation's assets may be subject to impairment. Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries, tariffs, and ongoing credit and liquidity concerns. 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. In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base determined by its lender. The lender uses the Corporation's reserves, commodity prices, and other factors, to periodically determine the Corporation's borrowing base.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Worldwide crude oil commodity prices are expected to remain volatile in the near future as a result of global excess supply, recent actions taken by OPEC, and ongoing global credit and liquidity concerns. This volatility may affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Indigenous Land and Rights Claims

Opposition by Indigenous groups to the conduct our operations, development or exploratory activities in any of the jurisdictions in which the Corporation conducts business 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 progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. There are outstanding Indigenous and treaty rights claims, which may include Indigenous title claims, on lands where the Corporation operates, and such claims, if successful, could have a material adverse impact on its operations or pace of growth. No certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. The Corporation is not aware that any claims have been made in respect of the Corporation's assets. However, if a claim arose and was successful, it could have an adverse effect on the Corporation and its operations.

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 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. As noted in "*Information Concerning the Oil and Natural Gas Industry – Indigenous Rights*" in this Annual Information Form, the Blueberry Decision, from the British Columbia Supreme Court determined that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nations group on Treaty 8 lands in northeast British Columbia breached that group's treaty rights. Going forward, this decision may have significant impacts on the regulation of industrial activities in northeast British Columbia, including Treaty 8 lands where a substantial portion of the Corporation's land will be situated. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties. The long-term impacts of and associated risks of the decision on the Canadian oil and natural gas industry and the Corporation remain uncertain.

In addition, as noted in "*Information Concerning the Oil and Natural Gas Industry – Indigenous Rights*" in this Annual Information Form, to implement the UNDRIP the federal government passed the UNDRIP Act, the BC Government has passed DRIPA, and the Government of British Columbia issued a draft action plan in June 2021 for the implementation of DRIPA which contemplates enabling agreements with Indigenous governing bodies, including joint or consent-based decision-making agreements that reflect free, prior and informed consent. Other Canadian jurisdictions, have also introduced or passed similar legislation, or 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 amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

The federal government is in the process of developing various regulatory regimes that could create new requirements when doing business with Indigenous groups and on or near First Nation lands, for example, Bill C-226, *National Strategy Respecting Environmental Racism and Environmental Justice Act*, which received royal assent in June 2024, the new Indigenous co-administration agreement provisions of the *Impact Assessment Act* for which regulations, policy, guidance and procedures are forthcoming, and the proposed Bill C-61, *First Nations*

Clean Water Act, which is currently being considered by the House of Commons. The introduction of such new regulatory schemes has the potential to disrupt the Corporation's ongoing activities and introduce uncertainty into potential future projects.

On May 31, 2017, the British Columbia Supreme Court denied an injunction application brought by the BRFN which sought to restrain the Province of British Columbia from, among other things, permitting new oil and gas activities within a portion of northeast British Columbia, including Treaty 8 lands where a substantial portion of the Corporation's land will be situated. Had the injunction application been successful, it would likely have had a material adverse impact on the Corporation, its operations and production. The interlocutory injunction was part of an underlying claim by the BRFN against the Province of British Columbia, filed on March 3, 2015, which seeks relief for alleged breaches of treaty rights in northeast British Columbia. On June 29, 2021, the British Columbia Supreme Court issued the Blueberry Decision to address this underlying claim and determined that the cumulative impacts of industrial development on the traditional territory of the BRFN in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. On January 18, 2023, the Government of British Columbia and the BRFN signed 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 crude oil and natural gas development, and a new planning regime for future crude oil and natural gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on crude oil and natural gas revenue sharing and provincial royalty revenue-sharing in the next two fiscal years. The BRFN Agreement now serves as a blueprint for other agreements between the Government of British Columbia and First Nations in Treaty 8 territory. The Blueberry Decision, the BRFN Agreement and the subsequent negotiations between BRFN and the Government of British Columbia as a result of the Blueberry Decision and the BRFN Agreement could have a material adverse effect on the Two Rivers Assets and have a material adverse impact on the Corporation. See "*Information Concerning the Oil and Natural Gas Industry – Indigenous Rights*" in this Annual Information Form.

Political Uncertainty

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 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 that the Corporation relies on. 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.

On February 1, 2025, U.S. President Donald Trump signed an executive order imposing tariffs of 25% on almost all goods imported from Canada, with a lower tariff of 10% imposed on Canadian energy and resources products including crude oil, natural gas, lease condensates, natural gas liquids and refined petroleum. In response, the Department of Finance Canada announced countermeasures with the imposition of 25% tariffs on certain goods imported from the United States. On February 3, 2025, it was announced that the implementation of such announced tariffs would be suspended for 30 days. Subsequently, on March 4, 2025, the tariffs came into effect as initially promulgated, however, some of the tariffs were paused from March 6, 2025 until April 2, 2025. On April 3, 2025, the tariffs resumed. On April 9, 2025, President Donald Trump implemented a 90-day pause on certain tariffs for several countries, however, this pause excluded Canada. These tariffs are expected to affect the pricing structure for natural gas, crude oil and related products exported from Canada to the United States, and are also expected to alter the competitiveness of, and market for, Canadian oil and natural gas imports into the United States. There remains substantial ambiguity regarding how long the tariffs will remain in place and whether the tariffs will be increased. Additionally, the precise effect of the tariffs on the Canadian economy and Canadian energy producers is yet to be determined, but it is expected to have an adverse effect if the tariffs are maintained.

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, and the success of these initiatives may decrease demand for the Corporation's products.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Corporation's activities.

International Conflict

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising outside of Canada, have a significant impact on the price of oil and natural gas. Specifically, hostilities in the Middle East, Ukraine, and Taiwan and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

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

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. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy.

In addition, certain countries including Canada have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. In addition, in September 2022 the 1,200 kilometre twin Nord Stream natural gas pipelines that were built to carry natural gas from Russia to Germany exploded underwater, likely as a result of sabotage. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply of energy and high prices of oil and natural gas could have a significant adverse impact on the world economy.

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. This conflict has significantly broadened with Israel also battling Hezbollah in Lebanon and significant conflict between Israel and Iran and other Iran backed proxies in the area. In addition, recently the Syrian Assad regime has fallen and it is unknown whether a stable Syrian government will develop.

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. To date, these events have not impacted the Corporation's ability to carry on business, and there have been no significant delays or direct security issues affecting the Corporation's operations, offices or personnel. The long-term impacts of the conflict remain uncertain and the Corporation continues to monitor the evolving situation.

In addition, attacks by Houthi rebels in the Red Sea has put significant risks on shipping lanes in the area and has resulted in increased shipping costs to various business entities. Continued attacks on shipping in the Middle East may result in further increases in shipping costs and longer transit times and delays in delivering products or procuring supplies. Further escalation of the conflict may spark confrontations in other parts of the Middle East and have further adverse consequences on global markets, commodity prices, supply chains and shipping lanes and the Corporation's business. The Corporation continues to monitor these events and will proactively manage the situation, although there is no assurance that the Corporation's operations will not be adversely affected by current geopolitical tensions and/or associated government sanctions.

Inflation and Rising Interest Rates

Recently, Canada, the United States and other countries have experienced high levels of inflation, supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs and commodity prices, and additional government intervention through stimulus spending and additional regulations. These factors have increased the operating costs of the Corporation. The Corporation's inability 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.

The cost or availability of oil and gas field equipment may adversely affect the Corporation's ability to undertake exploration, development and construction projects. The oil and natural gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available at reasonable prices when required. A failure to secure the services and equipment necessary to the Corporation's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Corporation's financial performance and cash flows.

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 to combat inflation. The rise in interest rates has impacted the Corporation's borrowing costs. The increase in borrowing 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. Rising interest rates could also result in a recession in Canada, the United States or other countries. A recession may have a negative impact on demand for oil and natural gas, causing 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 how inflation and rising interest rates will impact oil and gas demand and commodity prices.

Capital Markets

As a result of the weakened global economic situation, the Corporation, along with all other oil and gas entities, may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Although the Corporation's business has not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, borrowings and possible future equity sales, the Corporation's ability to make such capital expenditures will be dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Corporation's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

If funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if the Corporation incurs major unanticipated expenses related to development or maintenance of its existing properties, it will be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

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 to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also 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 assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, 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 thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were 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 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 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 has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Reserve Replacement

The Corporation's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on the Corporation successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on the Corporation's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that the Corporation's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Impact of Pandemics, Epidemics and Infectious Diseases

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide, including COVID-19, Middle East Respiratory Syndrome, Severe Acute Respiratory Syndrome, H1N1 influenza virus, avian flu or any other similar illnesses could have an adverse impact on, among other things, the Corporation's business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans as a result of, and without limitation:

- the shut-down of facilities or the delay or suspension of work on major capital projects due to workforce disruption or labour shortages caused by workers becoming infected with an infectious disease, or government or health authority mandated restrictions on travel by workers or closure of facilities or worksites;
- suppliers and third-party vendors experiencing similar workforce disruption or being ordered to cease operations;
- reduced cash flows resulting in less funds from operations being available to fund capital expenditure budgets;
- reduced commodity prices resulting in a reduction in the volumes and value of reserves;
- crude oil storage constraints resulting in the curtailment or shutting in of production;
- counterparties being unable to fulfill their contractual obligations on a timely basis or at all;
- the inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate; and
- the ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into tight rock formations to stimulate hydrocarbon (natural gas and oil) production. The use of hydraulic fracturing is necessary to produce commercial quantities of natural gas and oil from many reservoirs. 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 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. The Corporation anticipates that federal, provincial and state regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. The Corporation's prospects may also be negatively impacted, any of which may have a material adverse effect on the Corporation's business, financial condition and results of operations. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves. The Corporation conducts its fracturing operations with reputable service providers, with due regard for potential impact on the environment and closely monitors and complies with the regulatory regime.

Water is an essential component of the Corporation's drilling and hydraulic fracturing processes. Limitations or restrictions on the Corporation's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. 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 is unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on its financial condition, results of operations, and cash flows.

In addition, the Corporation must dispose of the fluids produced from oil, liquids and natural gas production operations, including produced water, which it does directly or through the use of third-party vendors. 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 regarding such disposal activities.

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 or by commercial disposal well vendors that the Corporation 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 or its vendors 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. See "*Information Concerning the Oil and Natural Gas Industry – Environmental Regulation*" in this Annual Information Form.

Project Risks

The Corporation will manage a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability 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 and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour;
- the regulation of the oil and natural gas industry by various levels of government; and
- governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

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.

Expiration of Licences and Leases

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation may make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as 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 business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management will continually assess the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets may be periodically disposed of, so that 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, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Availability of Drilling Equipment and Access

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

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial 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 if not otherwise tied-in. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation. 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.

Operational Dependence

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

Joint Ownership

Many of the Corporation's material assets are jointly held and are governed by contractual arrangements. As a result, certain decisions regarding these assets require the approval of the Corporation's partners. While the Corporation believes that it will have prudent governance and contractual rights in place, there can be no assurance that the Corporation will not encounter disputes with partners that may impact operations or cash flows.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. 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, poor credit conditions in the industry and of joint venture partners may impact 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.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "*Information Concerning the Oil and Natural Gas Industry"* in this Annual Information Form. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry.

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

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, 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. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. 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 and provincial 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.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. In November 2024, the federal government published a draft of the proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations, which, if enacted as currently drafted, would cap emissions from a range of industrial activities in the oil and gas sector, establish a cap-and-trade system for emissions allowances, and require facility operators to comply with various reporting and remittance obligations. Such proposed regulations, which could affect investor confidence, suppress spending on decarbonization initiatives and lead to production cuts, are expected to be finalized in mid-2025 and come into force by January 1, 2026.

On June 20, 2024, Bill C-59 received royal assent, thereby enacting certain changes to the Competition Act to address "greenwashing", meaning false, misleading, or deceptive environmental claims made for the purpose of promoting a product or a business interest. Under the new rules, certain environmental claims that companies commonly make, including those related to sustainability and forward-looking environmental-related goals, may be problematic. How the new rules will be interpreted and applied is currently unclear. In June 2025, new private rights of action will come into effect, meaning that any person will be able to bring a complaint directly to the Competition Tribunal for an alleged violation of the new greenwashing provisions. The Competition Bureau has published draft guidance regarding how it will apply the new greenwashing provisions, however the guidance, even once finalized, is not and will not be binding on private parties nor the Competition Tribunal. Companies found to have made representations that violate the rules, intentionally or inadvertently, could be subject to an administrative penalty for the greater of $10 million for the first order and $15 million dollars for any subsequent order, and 3% of the corporation's annual worldwide gross revenues.

Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws 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 across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada made several pledges aimed at reducing Canada's GHG emissions and environmental impact, and at the 2024 UN Climate Change Conference, Canada reaffirmed its commitments to transitioning away from fossil fuels and further cutting emissions. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations. 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.

The Corporation's exploration and production facilities and other operations and activities emit GHGs and may require the Corporation to comply with future federal legislation in Canada regulating emissions of GHGs. The future implementation or modification of GHG regulations could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Information Concerning the Oil and Natural Gas Industry – Climate Change Regulation*" in this Annual Information Form.

<u>Transition Risks</u>

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as 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 multilateral 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 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 Corporation's operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, 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. As a result, individuals, government 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, may adversely affect the Corporation's operations, the demand for and price of the Corporation's securities and may negatively impact 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, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators 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 with limited exceptions. 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.

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 Corporation's ability to access its 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. Certain of the Corporation's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Corporation's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

Competition

The petroleum industry is competitive in all its phases. The Corporation will compete with numerous other organizations in the exploration, development, production and marketing of oil and natural gas. The Corporation's competitors will include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis.

As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop the Corporation's assets, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory and development drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Hedging

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

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

Insurance

The Corporation's proposed involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation will maintain 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, such 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 will 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.

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 devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of hydrocarbons 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 flows by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation will deliver its products through gathering and processing facilities and pipeline systems some of which it does not own and by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

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

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

Enforcement of Operating Agreements

Operations of the wells located on properties not operated by the Corporation will generally be governed by operating agreements that typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation.

Fiscal and Royalty Regimes

In addition to federal regulation, each province has legislation and regulations which govern land tenure, drilling and construction permits, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, commodity prices, geographical location, field discovery data and the type or quality of the petroleum product produced.

The royalty regime in British Columbia and any other jurisdictions in which the Corporation's oil and natural gas assets are located, may be subject to further review and changes which could adversely impact the Corporation's financial condition and operations and make future capital investments less economic. See "*Information Concerning the Oil and Natural Gas Industry – Royalties and Incentives*" in this Annual Information Form.

Liability Management

British Columbia has developed a liability management program designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. The BCER continues to implement the BC CLM Plan, particularly by way of replacing the BC LMR Program with the BC PCA Program. The implementation of the new BC PCA Program or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted, increased and more frequent financial disclosure obligations or the denial of licence or permit transfers, which could impact the availability of capital to be spent by the Corporation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. This is of particular concern to junior oil and gas companies as they may be disproportionately affected by price instability. See "*Information Concerning the Oil and Natural Gas Industry – Liability Management Rating Programs*" in this Annual Information Form.

Breach of Confidentiality

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

Litigation

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

Information Technology Systems and Cyber-Security

The Corporation relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Corporation is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data, compromise confidential customer or employee information, result in the disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage. In addition, information systems could be damaged or interrupted by natural disasters, force majeure events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on the Corporation's business, financial condition, results of operations and cash flows.

In the ordinary course of business, the Corporation collects, uses and stores sensitive data, including intellectual property, proprietary business information and personal information of the Corporation's employees and third parties. Despite the Corporation's security measures, its information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions. Any such breach could compromise information used or stored on the Corporation's systems and/or networks and, as a result, the information could be accessed, publicly disclosed, lost or stolen.

To date the Corporation has not experienced any material losses relating to cyber-attacks or other information security breaches. However, there can be no assurance that the Corporation will not incur such losses in the future. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties or other negative consequences, including disruption to the Corporation's operations and damage to its reputation, which could have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows. Although the Corporation maintains a risk management program, which includes an insurance component that may provide coverage for the operational impacts from an attack to, or breach of, the Corporation's information technology and infrastructure, including process control systems, the Corporation does not maintain stand-alone cyber insurance. Furthermore, not all cyber risks are insurable. As a result, the Corporation's existing insurance may not provide adequate coverage for losses stemming from a cyber-attack to, or breach of, its information technology and infrastructure.

Although to date the Corporation has not experienced any material losses relating to cyber-attacks or other information security breaches, there can be no assurance that the Corporation will not incur such losses in the future.

Delays in Business Operations

In addition to the usual delays in payments by purchasers of oil and natural gas to the Corporation or to the operators, and the delays by operators in remitting payment to the Corporation, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Corporation in a given period and expose the Corporation to additional third party credit risks.

Income Taxes

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

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

Risks Relating to the Management of the Corporation

Reliance on Key Personnel

The Corporation's success will depend in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not, and will not, have any key person insurance in effect for the Corporation. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of the business of the Corporation. Any inability on the part of the Corporation to attract and retain qualified personnel may delay or interrupt the exploration for, and development and production of, oil and natural gas with respect to the Corporation's assets. Sustained delays or interruptions could have a material adverse effect on the financial condition and performance of the Corporation. In addition, rising personnel costs would adversely impact the costs associated with the exploration for, and development and production of, oil and natural gas in respect of the Corporation's assets, which could be significant and material.

Potential Conflicts of Interest

There may be circumstances in which the interests of the Corporation and its affiliates will conflict with those of shareholders. The Corporation and its affiliates may acquire oil and natural gas properties on their own behalf or on behalf of persons other than the shareholders. Neither the Corporation, nor its management, will carry on their full-time activity on behalf of shareholders and, when acting on their own behalf or on behalf of others, may at times act in competition with the interests of shareholders.

In the event of such conflicts, decisions will be made on a basis consistent with the provisions of any relevant contractual arrangements and objectives and financial resources of each group of interested parties. The Corporation will use all reasonable efforts to resolve such conflicts of interest in a manner which will treat the Corporation, and the other interested party, fairly taking into account all of the circumstances of the Corporation and such interested party and to act honestly and in good faith in resolving such matters.

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

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of 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.

Management of Growth

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

Internal Controls

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

Risks Relating to the Common Shares

Market Price of Common Shares

The market price of the Common Shares may be volatile. The volatility may affect the ability of holders to sell Common Shares at an advantageous price. Market price fluctuations in the Common Shares may be due to the Corporation's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, lack of liquidity, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "Forward-looking Statements". In addition, the market price for securities in the stock markets, including the TSXV, recently experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market price of the Common Shares.

Substantial Capital Requirements

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, the Corporation may have limited ability to expend the capital necessary to undertake or complete future drilling programs. 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. Moreover, future activities may require the Corporation to alter its capitalization significantly, including transactions involving the issuance of securities, which may be dilutive. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. 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 in the future on a timely basis to take advantage of business opportunities that may arise.

Future Sales and Issuances of Common Shares

The Corporation may issue additional Common Shares in the future, which may dilute a shareholder's holdings in the Corporation. The Corporation's articles permit the issuance of an unlimited number of Common Shares and shareholders will have no pre-emptive rights in connection with such further issuances. The directors of the Corporation have the discretion to determine the terms of issue of further issuances of Common Shares. Also, additional Common Shares will be issued by the Corporation on the exercise of stock options under the Corporation's stock option plan. In addition, 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.

Variations in Foreign Exchange Rates and Interest Rates

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

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

Dividends

The Corporation is not obligated to pay dividends on the Common Shares. The payment of dividends is at the sole discretion of the Corporation's board of directors and, as at the date hereof, the Corporation has not paid dividends. Any reduction or elimination of dividends could cause the market price of the Common Shares to decline and could further cause the Common Shares to become less liquid, which may result in losses to shareholders.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

To the knowledge of the management of the Corporation, there are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated.

Regulatory Actions

To the knowledge of management of the Corporation, no penalties or sanctions have been imposed by a court relating to securities legislation or by a securities regulatory body or by any other court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision, nor have any settlement agreements been entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as discussed herein, there are no material interests, direct or indirect, of any of the directors or executive officers of the Corporation, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of outstanding voting securities of the Corporation or any associate or affiliate of such persons or companies in any transaction during the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal office located in Calgary, Alberta.

MATERIAL CONTRACTS

On October 4, 2024, the Company secured two revolving bank credit facilities for a total of $52.0 million from a Canadian chartered bank. The credit facilities are backed by reserves at Two Rivers West plus a $45.0 million letter of credit from a third party. The commitment from the third party is for a two-year term. During the term, Coelacanth expects that the lending value of producing reserves at Two Rivers East will allow for the credit facility to be renegotiated and the letter of credit to be returned.

The first credit facility is a $7.0 million revolving operating demand loan credit facility that bears interest at prime plus 3.0%. The undrawn portion of the credit facility is subject to a standby fee of 1.0%. Any outstanding letters of guarantee reduce the amount that can be borrowed under the credit facility and bear interest at 4.0%. During the year ended December 31, 2024, the Company redeemed $5.4 million of restricted cash deposit GIC's and issued letters of guarantee for the same amount under the revolving operating demand loan credit facility thereby reducing the amount available from $7.0 million to $1.6 million.

The second credit facility is a $45.0 million revolving operating demand loan that bears interest at prime plus 0.25%. The undrawn portion of the credit facility is subject to a standby fee of 0.125%. This credit facility is secured by a $45.0 million letter of credit from a third party. The letter of credit fee is 3.0% of the total $45.0 million face value of the letter of credit whether drawn or not for the first one-year term plus the period prior to the start of the first term. The first term starts the earlier of when drawn or December 31, 2024. The Company has the option to extend the term by an additional maximum one-year term for a fee of 6% of the drawn portion of the letter of credit that can be reduced at any time by repayment of the credit facility.

The credit facilities and letter of credit are secured by a $75.0 million fixed and floating charge debenture on the assets of the Company. The next review of the credit facilities by the bank is scheduled on or before June 30, 2025.

The credit facilities include a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. The adjusted working capital ratio, as defined by its creditor, is calculated as current assets plus any undrawn amounts available on its demand loan credit facilities less current liabilities excluding any current portion drawn on the demand loan credit facilities. The definition of current assets and current liabilities excludes the fair value of risk management contracts.

On March 3, 2025, the Company received $22.7 million from a mid-stream company to finance a pipeline connecting Coelacanth facilities to the mid-stream company's gathering system. The Company is required to repay the principal amount over a five-year period at an effective interest rate of 12.0%.

Other than as noted above, the Corporation did not enter into any material contracts outside the ordinary course of business within the most recently completed financial year or prior thereto that are still in effect.

INTERESTS OF EXPERTS

KPMG LLP are the auditors of the Corporation and GLJ is the independent qualified reserve evaluator. KPMG LLP is independent of the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

None of the principles of GLJ had any registered or beneficial interests, direct, indirect, in any securities or other property of the Corporation at the time they prepared the statement, report or valuation by it, at any time there after or to be received by them.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR+ at www.sedarplus.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Corporation's current information circular found on SEDAR+ at www.sedarplus.com. Additional financial information is provided in the Corporation's financial statements and MD&A for the year ended December 31, 2024.

APPENDIX "A"
FORM 51-101F2
REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Coelacanth Energy Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table sets forth the estimated 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 Company evaluated by us for the year ended December 31, 2024, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

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 - M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	Dec. 31, 2024	Canada	-	239,640	-	239,640

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 their respective preparation dates.

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

EXECUTED as to our report referred to above:

GLJ Ltd., Calgary, Alberta, Canada, March 26, 2025.

(signed) *"James T.F. Guy"*
Name: James T.F. Guy, P. Eng.
Title: Manager, Engineering

APPENDIX "B"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Terms to which meanings are ascribed in National Instrument 51-101 have the same meanings herein.

Management of Coelacanth Energy Inc. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Evaluation Committee of the board of directors of the Company has:

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

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

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

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

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

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

(c) the content and filing of this report.

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

(signed) "*Robert Zakresky*"
Robert Zakresky
President and Chief Executive Officer

(signed) *" Harvey Doerr "*
Harvey Doerr
Director

(signed) *"Bret Kimpton"*
Bret Kimpton
Vice President, Operations and Chief Operating Officer

(signed) *"William Lancaster"*
William Lancaster
Director

Dated: April 23, 2025

APPENDIX "C"

AUDIT COMMITTEE CHARTER

1. PURPOSE

The overall purpose of the Audit Committee (the "**Committee**") of the Board of Directors (the "**Board**") is to assist the Board in fulfilling its oversight responsibilities and to carry out the functions associated with an audit committee of an issuer of the size and nature of the Corporation. The purpose of the Committee is to ensure that the Corporation's management has designed and implemented an effective system to review and report on the integrity of the financial statements of the Corporation. As part of this mandate, the Committee shall take all necessary steps so as to ensure compliance by the Corporation with all laws and regulatory policies, rules, regulations and instruments pertaining to audit and financial reporting that are applicable to the Corporation from time to time.

2. COMPOSITION, PROCEDURES AND ORGANIZATION

(a) The Committee shall consist of not less than three members of the Board, each of whom:

(i) must be "independent" ("independent" means that the audit committee has no direct or indirect material relationship with the Corporation, being a relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a member's independent judgment (and certain individuals are deemed by Multilateral Instrument 52-110 to have a material relationship)); and

(ii) must be "financially literate" ("financially literate" means a member has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements);

except as may be allowed under any applicable exemptions provided for under applicable laws or any exemption orders obtained from applicable regulatory authorities.

(b) The Board, at its organizational meeting held in conjunction with each annual general meeting of the holders of shares of the Corporation, shall appoint the members of the Committee for the ensuing year. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

(c) Unless the Board shall have appointed a chair of the Committee, the members of the Committee shall elect a chair from amongst their number. If the chair of the Committee is absent from any meeting, the Committee shall select one of the other members of the Committee to preside at that meeting.

(d) The Secretary of the Corporation shall be the secretary of the Committee, unless otherwise determined by the Committee. Minutes of meetings of the Committee shall be recorded and maintained by the Secretary of the Committee. Copies of the minutes shall be provided to the Board.

(e) The quorum for meetings shall be at least two of the members (the "**Members**") of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

(f) The Committee shall have access to such officers and employees of the Corporation and of the other consolidated subsidiaries of the Corporation, and to the Corporation's external auditors and to such information respecting the Corporation, as the Committee considers to be necessary or advisable in order to perform its duties and responsibilities.

(g) Meetings of the Committee shall be conducted as follows:

  (i) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the Chairman, and the Corporation's external auditors or any member of the Committee may request a meeting of the Committee;

  (ii) the Corporation's external auditors shall receive notice of and have the right and shall be encouraged to attend all meetings of the Committee; and

  (iii) the Chief Executive Officer and the Chief Financial Officer of the Corporation shall be invited to attend all meetings of the Committee, except executive sessions and private sessions with the external auditors, and other management representatives of the Corporation shall be invited to attend as necessary.

(h) The internal auditors of the Corporation (if any) and the external auditors of the Corporation shall have a direct line of communication to the Committee through the Chairman. The Corporation shall require the external auditors of the Corporation to report directly to the Committee.

3. **DUTIES AND RESPONSIBILITIES**

(a) The overall duties and responsibilities of the Committee shall be as follows:

  (i) assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and approve the Corporation's annual and quarterly financial statements;

  (ii) assess the qualifications of the external auditors;

  (iii) establish and maintain a direct line of communication with the Corporation's internal (if any) and external auditors and assess their performance;

  (iv) identify principal business risks;

  (v) ensure that the management of the Corporation has designed, implemented and is maintaining an effective system of disclosure controls and internal controls for the Corporation by requiring that management report at least quarterly on the measures in place, the testing done to ensure effectiveness, any areas where improvement is needed and whether there are any issues relating to the signing of the certifications required under Multilateral Instrument 52-109;

  (vi) report regularly to the Board on the fulfilment of the duties and responsibilities of the Committee;

  (vii) confirm that the Corporation's Disclosure Policy is adequate to ensure the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements is appropriate and periodically test the adequacy of the procedures mandated by such policy;

(viii) assess the effectiveness of the Board's duties and actions under the Disclosure and Confidentiality Policy;

(ix) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management and recommend changes to the Board;

(x) review compliance with the Code of Business Conduct and Ethics and periodically review this policy and recommend to the Board changes which the Committee may deem appropriate; and

(xi) review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation.

(b) The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:

(i) recommend to the Board a firm of external auditors to be engaged by the Corporation;

(ii) review and approve the fee, scope and timing of the audit and other related services rendered by the external auditors;

(iii) oversee the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management of the Corporation and the external auditor regarding financial reporting;

(iv) review the audit plan of the external auditors prior to the commencement of the audit;

(v) review with the external auditors, upon completion of their audit, the:

(A) contents of their report;

(B) scope and quality of the audit work performed;

(C) adequacy of the Corporation's financial and auditing personnel;

(D) co-operation received from the Corporation's personnel during the audit;

(E) internal resources used;

(F) significant transactions outside of the normal business of the Corporation;

(G) the major points contained in the auditor's management letter resulting from control evaluation and testing; and

(H) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems;

(vi) pre-approve all non-audit services to be provided to the Corporation by the external auditor in accordance with applicable laws;

(vii) periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal audit staff or by the external auditors have been implemented; and

(viii) meet *in camera* (i.e. without the presence of management of the Corporation) with the external auditors at least once a year prior the approval of the audited annual financial statements of the Corporation and at such other times as determined necessary or appropriate by the Committee.

(c) The duties and responsibilities of the Committee as they relate to the Corporation's internal auditors (if any) shall be as follows:

(i) periodically review the internal audit function with respect to the organization, staffing and effectiveness of the internal audit department;

(ii) review and approve the internal audit plan; and

(iii) review significant internal audit findings and recommendations, and management's responses thereto.

(d) The Committee is also charged with the responsibility to:

(i) review and approve the Corporation's financial statements (annual and interim) and MD&A (annual and interim) as well as the financial sections of prospectuses and other public reports requiring approval by the Board before such documents are publicly disclosed by the Corporation;

(ii) review regulatory filings and decisions as they relate to the Corporation's financial statements;

(iii) review the minutes of any audit committee meeting of associated companies, partnerships or trusts;

(iv) review the Corporation's accounting policy and discuss the impact of proposed changes in accounting standards;

(v) review with management, the external auditors and if necessary with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material effect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the financial statements;

(vi) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters;

(vii) establish procedures for the confidential, anonymous submission by employees of the Corporation or any other consolidated subsidiary of the Corporation of concerns regarding questionable accounting or auditing matters;

(viii) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation;

(ix) develop a calendar of activities to be undertaken by the Committee for each ensuing year and to submit the calendar in the appropriate format to the Board following each annual general meeting of shareholders; and

(x) on an annual basis, review and assess the adequacy of the Charter and the performance of the Committee in connection therewith.

(e) The Committee has the authority to:

(i) engage independent counsel and other advisors as it determines necessary to carry out its duties; and

(ii) set and pay the compensation for any advisors employed by the Committee.