RAZOR ENERGY CORP.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2022

May 1, 2023

TABLE OF CONTENTS

GLOSSARY

Certain terms and abbreviations used in this Annual Information Form are defined below:

"**ABCA**" means the *Business Corporations Act* (Alberta), as amended, including the regulations promulgated thereunder.

"**Affiliate**" or "**associate**" when used to indicate a relationship with a person or company, has the meaning set forth in the *Securities Act* (Alberta).

"**AIF**" means this annual information form dated May 1, 2023 for the financial year ended December 31, 2022.

"**AIMCo**" means Alberta Investment Management Corporation.

"**AIMCo Term Loan**" has the meaning attributed thereto in "*Three-Year History*".

"**Amended Term Loan Facility**" has the meaning attributed thereto in "*Three-Year History*".

"**Arena Amended Term Loan**" has the meaning attributed thereto in "*Three-Year History*".

"**Arena Amended and Restated Term Loan**" has the meaning attributed thereto in "*Three-Year History*".

"**Arena Term Loan**" has the meaning attributed thereto in "*Three-Year History*".

"**Arrangement**" has the meaning attributed thereto in "*Name, Address and Incorporation"*.

"**Board**" or "**Board of Directors**" means the board of directors of the Company, as constituted from time to time, including where applicable, any committee thereof.

"**Common Shares**" means the common shares in the capital of the Company.

"**Company**" or "**Razor**" means Razor Energy Corp.

"**CPC**" means a corporation:

a. that has been incorporated or organized in a jurisdiction in Canada;
b. that has filed and obtained a receipt for a preliminary CPC prospectus from one or more of the securities regulatory authorities in compliance with the Policy 2.4 of the TSXV; and
c. in regard to which the completion of the Qualifying Transaction has not yet occurred.

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

"**Qualifying Transaction**" means a transaction where a CPC acquires Significant Assets other than cash, by way of purchase, amalgamation, merger or arrangement with another company or by other means and, for the purposes of this AIF, the reverse takeover of the Company by Razor Private.

"**Razor Private**" means Razor Energy Corp., a private company incorporated under the ABCA on June 14, 2016.

"**Shareholders**" means the holders of Common Shares.

"**Sproule Report**" means the independent engineering evaluation of the oil and natural gas reserves attributable to the properties of the Company prepared by Sproule dated February 24, 2023 and effective December 31, 2022.

"**Swan Hills Unit 1 Working Interest Acquisition**" means the acquisition of certain oil and gas assets located in the Swan Hills area of Alberta from an arm's length public oil and gas company for aggregate consideration of $6.3 million, including customary closing and post-closing reconciliation adjustments.

"**TSXV**" or "**Exchange**" means the TSX Venture Exchange.

CONVENTIONS

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information with respect to the Company has been presented in Canadian dollars in accordance with International Financial Reporting Standards ("**IFRS**"). The information in this AIF is stated as at December 31, 2022, unless otherwise indicated.

ABBREVIATIONS

	Oil and Natural Gas Liquids		***Natural Gas***
Bbl	barrel	GJ	gigajoule
Bbls	barrels	Mcf	thousand cubic feet
BOPD	barrel of oil per day	Mmcf	million cubic feet
Mbbl	thousand barrels	Mcf/d	thousand cubic feet per day
Bbls/d	barrels per day	Mmcf/d	million cubic feet per day
NGLs	natural gas liquids	MMBTU	million British Thermal Units

Other

AECO	Alberta Energy Company's natural gas storage facility located at Suffield, Alberta.
API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
m3	cubic metres
MBOE	1,000 barrels of oil equivalent

WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
$000 or M$	thousands of dollars

CONVERSION

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

To Convert From	***To***	***Multiply By***
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF may constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this AIF should not be unduly relied upon by investors. These statements speak only as of the date of this AIF and are expressly qualified, in their entirety, by this cautionary statement.

Forward-looking statements or information in this AIF include, but are not limited to, the characteristics of the Company's oil and natural gas interests, future production levels, projection of market prices, capital expenditures, exploration plans, development plans, acquisition and disposition plans and the timing thereof, operating and other costs, world-wide supply and demand for petroleum products, royalty rates and treatment under governmental regulatory regimes. In addition, this AIF may contain forward-looking statements attributed to third party industry sources.

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

- future revenues and costs (including royalties) and revenues and costs per commodity unit;
- recovery factors;
- the performance characteristics of the Company's oil and natural gas properties;
- well completions and the timing thereof;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production and timing of results therefrom;
- future development and growth prospects;
- ability to meet current and future obligations;
- future sources of funding for capital programs and future availability of such sources;
- future asset acquisitions or dispositions;
- future development costs and operating costs:
- development plans;
- our ability to continue as a going concern in the future;
- anticipated land expiries;
- treatment under governmental regulatory regimes and tax laws;
- the ability to obtain financing on acceptable terms or at all; and
- currency, exchange and interest rates.

With respect to forward-looking statements contained in this AIF, the Company has made assumptions regarding, among other things:

- the Company's ability to continue as a going concern going forward and realize our assets and discharge our liabilities in the normal course of business;
- oil and natural gas production levels;
- the success of the Company's operations and exploration and development activities;
- prevailing climatic conditions, commodity prices and exchange rates;

- the impact of increasing competition;
- availability of skilled labour, services and drilling equipment;
- timing and amount of capital expenditures;
- the legislative and regulatory environments of the jurisdictions where the Company carries on business or has operations;
- conditions in general economic and financial markets;
- availability of drilling and related equipment;
- availability of pipeline capacity and other major facilities;
- royalty rates and future operating costs;
- access to market for the Company's production; and
- the Company's ability to obtain additional financing on satisfactory terms, if needed.

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

- the possibility that we are not able to continue as a going concern and realize our assets and discharge our liabilities in the normal course of business;
- continued impact of COVID-19;
- volatility in market prices for oil and natural gas, interest and exchange rates;
- uncertainties associated with estimating oil and natural gas reserves;
- the risks of the oil and gas industry, such as operational risks and market demand;
- pipeline and third-party facility capacity constraints and access to sales markets;
- the ability of management to execute its business plan;
- governmental regulation of the oil and gas industry, including environmental regulation;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;
- geological, technical, drilling and processing problems;
- exploration and development activities are capital intensive and involve a high degree of risk;
- risks and uncertainties involving geology of oil and gas deposits;
- variability in geothermal resources;
- risks inherent in marketing operations, including credit risk;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Company's capital expenditures;
- stock market volatility and market valuations;
- failure to realize the anticipated benefits of acquisitions and dispositions;
- unanticipated operating events which could reduce production or cause production to be shut-in or delayed;
- hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;
- the ability to add production and reserves through development and exploration activities;
- uncertainties in regard to the timing of exploration and development activities;
- changes in general economic, market and business conditions;
- the effect of litigation proceedings, including the Action, on the Company's business;
- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;

- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third-party consents and approvals, as and when required;
- the availability of capital on acceptable terms or at all;
- cyber-security issues;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel; and
- the other factors considered under "*Risk Factors*" below.

Statements relating to "reserves" are deemed to be forward-looking statements or information, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitable in the future. There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. 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, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties and classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Company with respect to these reserves will vary from such estimates, and such variances could be material.

The Company has included the above summary of assumptions and risks related to forward-looking information provided herein in order to provide investors with a more complete perspective on the Company's current and future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained herein, and the documents incorporated by reference herein, are expressly qualified by this cautionary statement. Except as required by applicable securities laws, the Company does not undertake any obligation to publicly update or revise any forward-looking statements and readers should also carefully consider the matters discussed under the heading "Risk Factors" below.

The forward-looking statements or information contained herein are made as of the date hereof and the Company undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws.

Caution Respecting BOE

In this Annual Information Form, the abbreviation BOE means a barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency conversion ratio of 6 Mcf to 1 BOE, utilizing a conversion ratio of 6 Mcf to 1 BOE may be misleading as an indication of value.

Non-IFRS Measures

Certain financial measures in this document or in documents incorporated by reference herein do not have a standardized meaning as prescribed by IFRS and are therefore considered non-IFRS measures. These measures, such as netbacks, may not be comparable to similar measures presented by other issuers. The additional information should not be considered in

isolation or as a substitute for measures prepared in accordance with IFRS. Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging.

NAME, ADDRESS AND INCORPORATION

The Company was incorporated under the laws of the Province of Ontario as "2236235 Ontario Inc." on March 5, 2010.

On January 31, 2017, the Company completed its qualifying transaction by way of plan of arrangement (the "**Arrangement**"), whereby Razor Private, a private company incorporated on June 14, 2016, completed a reverse take-over of the Company (the "**Qualifying Transaction**"). On January 31, 2017, the Company changed its name to "Razor Energy Corp." On February 3, 2017, the Company and Razor Private were amalgamated and continued as "Razor Energy Corp." On February 3, 2017, the Company completed a continuance of the Company from Ontario into Alberta under the ABCA.

The Company is a reporting issuer in British Columbia, Alberta and Ontario. The Common Shares are listed on the TSXV under the trading symbol "**RZE**".

The Company's head office is located at 800, 500 - 5th Avenue S.W., Calgary, Alberta, T2P 3L5. The registered office of the Company is located at 800, 500 – 5th Avenue S.W., Calgary, Alberta, T2P 3K5.

As at December 31, 2022 the Company has five wholly owned subsidiaries, Blade Energy Services Corp. ("**Blade**"), FutEra Power Corp. ("**FutEra**"), Razor Resources Corp, Razor Holdings GP Corp., and Razor Royalties LP. In addition, FutEra has one wholly owned subsidiary, Swan Hills Geothermal Power Corp. All subsidiaries are incorporated under the laws of the Province of Alberta.

GENERAL DEVELOPMENT OF THE BUSINESS

Three-Year History

A description of the significant developments in the business of the Corporation over the last three completed financial years is set forth below.

Financial Year Ended December 31, 2020

In March 2020, the COVID-19 outbreak was declared a pandemic by the World Health Organization. Global commodity prices declined significantly as countries around the world enacted emergency measures to combat the spread of the virus. The decrease in oil demand and pricing volatility was unprecedented. However, since April, global supply and demand fundamentals improved as a result of OPEC+ and North American producers reducing production allowing for global inventories to continue to fall and economies reopening with global vaccination efforts.

In response to the COVID-19 pandemic, the Company implemented business procedures that comply with Alberta Health Guidelines and took a cautious and case-by-case approach to spending in 2020, focusing on low risk, low capital opportunities to increase field and corporate netbacks. Production levels were not a priority and in the early part of the second quarter of 2020 the Company shut in all of its operated heavy oil production, along with certain light oil wells which were sub-economic at the time, and also built oil inventory in anticipation of improved future crude oil prices. Starting in the later part of the second quarter, the Company began the process of restarting the heavy oil and light oil wells which were shut in and throughout the third quarter reduced oil inventory in response to improved crude oil prices.

At June 30, 2020 and December 31, 2020, the Company deferred interest payments owing to AIMCo for the Amended Term Loan Facility. The deferred interest amounts were added to the principal due at maturity on January 31, 2021.

Financial Year Ended December 31, 2021

On February 16, 2021, the Company extended the Amended Term Facility with AIMCo (the "**AIMCo Term Loan**") for an amended principal amount of $50.1 million, being the amounts outstanding with AIMCo on such date. Principal under the extended AIMCo Term Loan is due in full on January 31, 2024, with an interest rate of 10%, payable semi-annually. There were no additional proceeds received from the AIMCo Term Loan. As consideration for this extension a bonus payment of $3.5 million was added to the principal amount of the AIMCo Term Loan on July 31, 2021.

On February 16, 2021, Razor Royalties Limited Partnership ("**RRLP**"), a wholly owned subsidiary of Razor, entered into a new term loan with Arena Investors, LP ("**the Arena Term Loan**") of US$11.0 million (CAD$14.0 million). The proceeds are primarily to be used to fund a well activation and production enhancement program. The Arena Term Loan will be repaid over 29 months with principal and interest payments of approximately US$0.4 million per month, commencing April 1, 2021, and full repayment with interest of the loan on August 1, 2023. The Arena Term Loan carries a fixed annual interest rate of 7.875%. Security consists of a first lien on all assets within RRLP and Razor Holdings GP Corp. The Arena Term Loan is also secured by a second lien on the assets of Razor, excluding Razor's subsidiaries Blade, FutEra and its subsidiaries, and Razor Resources Corp.

On August 12, 2021, Razor completed the acquisition of certain non-operating working interest positions in its Swan Hills, Alberta core region. The Assets consist of Swan Hills Unit No. 1, Judy Creek Gas Plant and South Swan Hills Unit Gas Gathering System at 32.5%, 8.6% and 27.6% working interest, respectively. The acquisition allows Razor to further consolidate its existing working interest in the area to a 49.7% non-operated working interest in the Unit, as well as increasing its working interest in critical area infrastructure including the Plant and Gathering System to 38.1% and 43.9% respectively. The total purchase price is $6.3 million, subject to customary adjustments.

On August 12, 2021, RRLP entered into an amendment agreement on its Arena Term Loan ("**Arena Amended Term Loan**") with Arena Investors, LP for an additional US$8.8 million (CAD $11.0 million). The proceeds of which are primarily to fund the acquisition of the Swan Hills working interest (see above). The term of Arena Amended Term Loan is extended to April 1, 2024. Monthly principal and interest payments increased effective September 1 to approximately US$0.5 million per month with payments increasing to approximately US$0.7 million in 2022.

On October 22, 2021 Razor closed a private placement for a subscription price of $0.84 per common share (the "**Private Placement**"). AIMCo and certain members of Razor management subscribed for 2,250,000 Razor Shares with aggregate proceeds of $1,890,000. The proceeds of the Private Placement were used to continue Razor's well reactivation program and general corporate purposes.

Financial Year Ended December 31, 2022

On March 9, 2022, the Company closed a senior debt financing specifically for its Co-produced Geothermal Power Project (the "**Geothermal Project**") in Swan Hills, Alberta. The financing was funded by Arena Investors, LP by way of amending the Arena Amended Term Loan (the "**Arena Amended and Restated Term Loan**") for an additional principal amount of $11.0 million (CAD $14.1 million) (the "**Term Loan 3**"). Term Loan 3 matures after 48 months, and the Company has granted first lien security on the assets held within Swan Hills Geothermal Power Corp. along with FutEra's equity in Swan Hills Geothermal Power Corp. During months 1 to 24, the Company will make interest payments on the prevailing monthly principal balance at an annual interest rate of 7.875% and non-cash interest will also accrue on the prevailing monthly principal balance at an annual interest rate of 3%. During months 25 to 48, the Company will make principal payments at an annual amortization rate of 5% of the prevailing monthly principal balance, interest payments on the prevailing monthly principal balance at an annual interest rate of 7.875% and non-cash interest will also accrue on the prevailing monthly principal balance at an annual interest rate of 3%. The principal balance of Term Loan 3 at maturity is expected to be US$3.8 million (CAD$4.8 million).

On May 11, 2022, the Company closed a rights offering for eligible holders of its common shares (the "**Common Shares**"). Each holder of Common Shares resident in a province or territory in Canada received one right (a "**Right**") for each 1 Common Share held. Each whole Right entitled the holder to subscribe for 0.0841016 of a Common Share. As a result, holders of Common Shares needed to exercise 11.8903796 Rights to acquire one Common Share. A holder of Rights paid $2.55 to purchase one Common Share. A total of 23,314,466 rights were exercised, resulting in the issuance of 1,960,784 Common Shares for gross proceeds of $5.0 million. The Common Shares issued as a result of the rights offering were issued on a "flow-through" basis in respect of Canadian renewable and conservation expense ("**CRCE**") within the meaning of the Income Tax Act (Canada). Upon issuing the Common Shares to shareholders of Razor at the closing of the Rights Offering, Razor renounced 100% of the to-be-incurred eligible expenses to the Rights Offering subscribers which can be deducted from ordinary income in calculating the subscriber's liability for income tax. Razor and its subsidiaries are committed to incur an amount of eligible expenses equal to the Rights Offering proceeds prior to December 31, 2023.

On September 9, 2022, the Geothermal Project began producing power to the grid. The final stages of construction and commissioning continued throughout the fourth quarter of 2022 and into the first quarter of 2023.

Significant Acquisitions

The Company has not completed any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF THE BUSINESS OF THE COMPANY

The Company is a growth oriented light oil weighted company operating in Alberta focused on exploration, development and production. The Company is focused on growing through corporate and asset acquisitions, exploitation and improvement of existing production and infrastructure, complemented by development and exploration drilling. Razor's full-cycle business plan supports its position as a growth junior oil and natural gas production company.

As part of its growth strategy, Razor continues to strategically evaluate and search out oil and natural gas properties that will result in meaningful reserve and production additions. The Company prefers to concentrate capital to higher quality, longer life reservoirs in proved areas that offer existing infrastructure, low-cost drilling opportunities, year-round access and operational control. Razor's existing core operating properties in Alberta will continue to be optimized, developed, and expanded through a detailed technical analysis of available data, including reservoir characteristics, original crude oil and natural gas in place, recovery factors and the application of exploitation reactivations, re-entries, drilling and enhanced recovery techniques.

In each of its core areas, Razor's growth strategy is to:

1. acquire and consolidate complementary prospective lands and drilling location opportunities;

2. optimize areas with a combination of reactivating production, re-entering existing wellbores, modifying existing secondary recovery schemes, reconfiguring infrastructure, generally lowering operating costs, and improving safety and environmental stewardship;
3. build a sufficient inventory of land and drilling locations to support future growth; and
4. manage uncertainty through the technical and operating experience Razor has in each of the areas in which it operates.

To execute its business plan, Razor requires: (i) access to land and additional opportunities; (ii) appropriate commercial terms; (iii) access to services and goods for operations; (iv) acquisition and operational success; and (v) timely financing for all such activities.

In addition to Razor's upstream hydrocarbon business, the Company's two subsidiaries FutEra and Blade enhance Razor's operational efficiency and further diversifies Razor's commercial platform.

FutEra is an aspiring leader in transitioning the energy complex to cleaner power generation and sustainable infrastructure to meet society's desire for lower to no carbon energy solutions. FutEra leverages Alberta's resource industry innovation and experience to create transitional power and sustainable infrastructure solutions to commercial markets and communities, both in Canada and globally. FutEra recently commissioned the Geothermal Project, which is a 21 megawatt co-produced geothermal and natural gas hybrid power project in Swan Hills, Alberta. FutEra's development efforts will focus on larger scale, lower emissions natural gas and renewable electricity generation projects with similar themes leveraging Razor and other oil gas producer's to create financial and tactically advantaged development scenarios, and prospective competitive returns to investors.

Specialized Skill and Knowledge

The Company relies on the specialized skill and knowledge of its permanent staff to compile, interpret and evaluate technical data, drill and complete wells, design and operate production facilities and numerous additional activities required to explore for and produce oil and natural gas. From time to time, the Company employs consultants and other service providers to provide complementary experience and expertise to carry out its oil and natural gas operations effectively. It is the belief of management of Razor that its officers and employees, who have significant technical, operational and financial experience in the oil and gas industry, hold the necessary skill sets to successfully execute Razor's business strategy in order to achieve its corporate objectives.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. The Company competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include resource companies that have greater financial resources, staff and facilities than those of the Company. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. The Company believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development. See *"Risk Factors - Competition"*.

Cyclical and Seasonal Nature of Industry

Razor's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on Razor's financial condition. Furthermore, the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. See *"Risk Factors - Seasonality"*.

Environmental

The Company believes that it is in compliance with applicable existing environmental laws and regulations and is not aware of any proposed environmental legislation or regulations with which it would not be in material compliance. Procedures are put in place to ensure that the utmost care is taken in the day-to-day management of Razor's oil and gas properties. However, in the future, the natural resources industry may become subject to more stringent environmental protection rules. This could increase the cost of doing business and may have a negative impact on future earnings. See *"Industry Conditions"* and *"Risk Factors".*

Employees

As at December 31, 2022, the Company had 87 employees (comprised of 33 head office, 10 field operation employees and 44 oilfield service employees). In addition, the Company utilizes the services of contractor operators in its field operations.

Reorganizations

There have been no material reorganizations of the Company within the three most recently completed financial years or completed during or proposed for the current financial year.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data and Other Information as of Financial Year Ended December 31, 2022

The reserves data set forth below is based upon an evaluation by Sproule Associates Limited ("**Sproule**") and contained in the Sproule Report dated February 24, 2023. The effective date of this report is December 31, 2022 and was prepared for Razor between December 2022 and February 2023. The Sproule Report summarizes the crude oil, natural gas liquids and natural gas reserves of Razor and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("**COGEH**") and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Razor believes is important to the readers of this information. The following tables provide summary information presented in the Sproule Report effective December 31, 2022 and based on the Sproule December 31, 2022 price forecast.

As of the date hereof, Razor's reserves are located in the province of Alberta.

The Report on Reserves Data by Sproule and the Report of Management and Directors on Oil and Gas Disclosure are attached as Schedule A and Schedule B, respectively, to this AIF.

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

SUMMARY OF OIL AND GAS RESERVES
(FORECAST PRICES AND COSTS)
AS OF December 31, 2022

	Light & Medium Oil		Heavy Oil		Conventional Natural Gas		Natural Gas Liquids		Barrels of Oil Equivalent	
	Gross (Mbbl)	**Net** (Mbbl)	**Gross** (Mbbl)	**Net** (Mbbl)	**Gross** (Mmcf)	**Net** (Mmcf)	**Gross** (Mbbl)	**Net** (Mbbl)	**Gross** (MBOE)	**Net** (MBOE)
Proved										
Developed producing	5,999	4,719	186	163	7,111	6,689	1,730	1,401	9,100	7,398
Developed non-producing	2,939	2,322	109	99	1,503	1,346	1,750	1,412	5,048	4,058
Undeveloped	358	313	218	185	380	342	53	47	692	602
Total Proved	**9,296**	**7,354**	**513**	**447**	**8,994**	**8,378**	**3,532**	**2,860**	**14,840**	**12,058**
Total Probable	2,566	2,005	139	116	2,249	2,082	972	789	4,051	3,257
Total Proved plus Probable	**11,861**	**9,360**	**652**	**563**	**11,243**	**10,460**	**4,504**	**3,649**	**18,891**	**15,315**

Notes:

(1) Columns may not add due to rounding.

(2) Natural gas volumes include associated and non-associated gas.

(3) Natural gas is converted to a BOE at a ratio of six thousand standard cubic feet to one barrel of oil.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE
(FORECAST PRICES AND COSTS)
AS OF December 31, 2022

	Before Income Tax Discounted at Various Rates				Unit Value Before Income Tax
Description	**0%** M$	**5%** M$	**10%** M$	**15%** M$	**Discounted at 10%** $/BOE
Proved					
Developed Producing	(37,205)	84,820	95,625	89,977	12.93
Developed Non-Producing	120,951	87,701	67,850	54,737	16.72
Undeveloped	27,065	23,240	20,081	17,481	33.38
Total Proved	**110,812**	**195,760**	**183,556**	**162,195**	**15.22**
Total Probable	125,765	75,290	50,875	37,200	15.62
Total Proved plus Probable	**236,577**	**271,050**	**234,432**	**199,395**	**15.31**

Notes:

(1) Utilizes Sproule's price forecast as of December 31, 2022 as detailed below.

(2) Values are net of ADR and IWC.

(3) Columns may not add due to rounding.

(4) Unit values are based upon the Company's net reserves.

Description	After Income Tax Discounted at Various Rates 0% M$	5% M$	10% M$	15% M$	Unit Value After Income Tax Discounted at 10% $/BOE
Proved					
Developed Producing	(46,393)	78,476	91,109	86,678	12.31
Developed Non-producing	95,168	68,442	52,910	42,802	13.04
Undeveloped	20,835	17,748	15,228	13,169	25.32
Total Proved	**69,610**	**164,666**	**159,247**	**142,649**	**13.21**
Total Probable	101,635	59,377	39,640	28,820	12.17
Total Proved plus Probable	**171,244**	**224,043**	**198,887**	**171,468**	**12.99**

Notes:

(1) Utilizes Sproule's price forecast as of December 31, 2022 as detailed below.

(2) Values are net of ADR and IWC.

(3) Columns may not add due to rounding.

(4) Unit values are base upon the Company's net reserves.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
(FORECAST PRICES AND COSTS)
AS OF December 31, 2022

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Capital Development Costs (M$)	Abandonment / Other Costs (M$)	Future Net Revenue Before Income Taxes	Income Tax (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved	1,223,900	249,396	606,365	21,049	236,278	110,812	41,202	69,610
Total Proved Plus Probable	1,604,694	329,064	781,073	21,663	236,317	236,577	65,332	171,244

FUTURE NET REVENUE BY PRODUCT TYPE
(FORECAST PRICES AND COSTS)
AS OF December 31, 2022

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX (discounted at 10%/year) ($/boe)
Proved	Light and Medium Crude Oil including solution gas liquids	163,329	14.83
	Heavy Crude Oil including solution gas liquids	15,618	31.02
	Conventional Natural Gas including associate by-products	4,610	8.54
		183,556	
Proved Plus Probable	Light and Medium Crude Oil including solution gas liquids	209,392	14.94
	Heavy Crude Oil including solution gas liquids	19,662	31.03
	Conventional Natural Gas including associate by-products	5,378	8.03
		234,432	

Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report were Sproule's forecasts, as at December 31, 2022, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
(FORECAST PRICES AND COSTS)
AS OF December 31, 2022

Year	WTI Oil ($US/Bbl)	Canadian Light Sweet ($Cdn/Bbl)	Hardisty Bow River ($Cdn/Bbl)	Natural Gas AECO ($Cdn/MMBTU)	Exchange Rate ($US/$CDN)
Forecast					
2023	86.00	110.67	89.32	4.33	0.75
2024	84.00	101.25	90.72	4.34	0.80
2025	80.00	96.18	85.32	4.00	0.80
2026	81.60	98.10	87.03	4.08	0.80
2027	83.23	100.06	88.77	4.16	0.80
2028	84.90	102.06	90.55	4.24	0.80
2029	86.59	104.10	92.36	4.33	0.80
2030	88.33	106.18	94.20	4.42	0.80
2031	90.09	108.31	96.09	4.50	0.80
2032	91.89	110.47	98.01	4.59	0.80
Thereafter 2% inflation rate					

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.4% sulphur.

(2) Light Sweet Crude 40 degrees API, 0.3% sulphur at Edmonton.

(3) Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate. The plant gate price represents the price before raw gathering and processing charges are deducted.

Weighted average historical prices realized by the Company for the year ended December 31, 2022, was $116.87/Bbl for light crude oil, $100.78/Bbl for heavy oil, $49.47/Bbl for NGLs and $3.82/Mcf for natural gas.

	Q4-2022	Q3-2022	Q2-2022	Q1-2022	Q4-2021	Q3-2021	Q2-2021	Q1-2021
Average selling price								
Oil price ($/bbl)	105.66	113.36	132.76	112.18	90.00	82.29	76.33	65.71
NGL price ($/bbl)	42.55	45.58	60.66	49.12	42.67	38.08	30.95	33.49
Gas price ($/mcf)	5.34	5.26	7.26	4.95	5.03	3.44	2.81	3.20
Benchmark prices and foreign exchange rates								
OIL ($/bbl)								
WTI (USD)	82.63	91.56	108.42	94.38	77.17	70.55	66.11	57.75
WTI (CAD)	112.23	119.94	140.01	119.51	97.18	88.89	81.14	73.11
CAD/USD EXCHANGE RATE	0.74	0.76	0.78	0.79	0.79	0.79	0.81	0.79
WTI vs Canadian Light Sweet differential (CAD/bbl)	(3.77)	(2.86)	(2.26)	(2.06)	(5.04)	(5.88)	(3.81)	(6.65)
NATURAL GAS (CAD/mcf)								
AECO NGX AB-5a	5.09	4.18	7.23	4.76	4.64	3.63	3.10	3.14

The Abandonment, Decommissioning and Reclamation ("**ADR**") cost, discounted at year-end 2022, was $33.7 million, a decrease of $0.6 million from year-end 2021 ($34.3 million). The Inactive Well Cost ("**IWC**") discounted at year-end 2022, was $31.8 million, an increase of $2.7 million from year-end 2021 ($29.1 million).

Estimated ADR costs related to a working interest have been taken into account by Sproule for all active wells, inactive wells and facilities in determining the future net revenues. In addition, Sproule has also taken into account IWC related to a working interest in all inactive wells in determining the future net revenues.

The following table summarizes ADR and IWC deducted in the estimation of Razor's future net revenues before income tax discounted at various rates and escalated as per Sproule's December 31, 2022 price forecast. These expenditures are expected to occur between 2023 and 2078.

	Discounted at Various Rates			
Description	**0%** M$	**5%** M$	**10%** M$	**15%** M$
Abandonment, decommissioning and reclamation costs ("**ADR**")	235,373	70,773	33,730	21,749
Inactive well costs ("**IWC**")	50,710	39,466	31,833	26,447
Total	**286,083**	**110,239**	**65,563**	**48,196**

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

Reconciliations of Changes in Reserves and Future Gross Revenue

Reserve Reconciliation

The following tables reconcile the Company's reserves from December 31, 2021 to December 31, 2022, using forecast prices and costs. Key highlights include:

- Higher commodity pricing resulted in additional reserves.
- Disposition was due to a third party purchasing a disclaimed Non-Operated unit interest.

Proved Company Gross Reserves	**Light and Medium Oil (Mbbl)**	**Heavy Oil (Mbbl)**	**Conventional Natural Gas (Mmcf)**	**Natural Gas Liquids (Mbbl)**	**Total Oil Equivalent (MBOE)**
Opening balance, beginning of year	**11,449**	**631**	**7,183**	**2,915**	**16,193**
Acquisitions	-	-	-	-	-
Dispositions	(841)	-	(698)	(393)	(1,350)
Technical Revisions	(1,251)	(73)	2,072	1,023	45
Economic Factors	837	36	1,995	296	1,501
Production	(898)	(82)	(1,557)	(309)	(1,549)
Total Reserves, end of year	**9,296**	**513**	**8,994**	**3,532**	**14,840**

Probable Company Gross Reserves	**Light and Medium Oil (Mbbl)**	**Heavy Oil (Mbbl)**	**Conventional Natural Gas (Mmcf)**	**Natural Gas Liquids (Mbbl)**	**Total Oil Equivalent (MBOE)**
Opening balance, beginning of year	**3,490**	**173**	**1,820**	**926**	**4,892**
Acquisitions	-	-	-	-	-
Dispositions	(212)	-	(159)	(90)	(328)
Technical Revisions	(972)	(42)	61	52	(952)
Economic Factors	259	8	527	84	439
Production	-	-	-	-	-
Total Reserves, end of year	**2,565**	**139**	**2,249**	**972**	**4,051**

Proved Plus Probable Company Gross Reserves	**Light and Medium Oil (Mbbl)**	**Heavy Oil (Mbbl)**	**Conventional Natural Gas (Mmcf)**	**Natural Gas Liquids (Mbbl)**	**Total Oil Equivalent (MBOE)**
Opening balance, beginning of year	**14,939**	**804**	**9,003**	**3,841**	**21,085**
Acquisitions	-	-	-	-	-
Dispositions	(1,052)	-	(857)	(483)	(1,678)
Technical Revisions	(2,223)	(114)	2,132	1,075	(908)
Economic Factors	1,096	44	2,522	380	1,940
Production	(898)	(82)	(1,557)	(309)	(1,549)
Total Reserves, end of year	**11,861**	**652**	**11,243**	**4,504**	**18,891**

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in COGEH. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved undeveloped reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101.

Proved undeveloped reserves were assigned to two vertical wells in the Beaverhill Lake formation in Swan Hills, three Mannville horizontal wells in Badger and two Glauconitic horizontal wells in Jumpbush.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. 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.

As circumstances change and additional data becomes available, reserve 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 government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Razor does not anticipate any unusually high development costs or operating costs, any unusually high abandonment and reclamation costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Razor's future net revenue attributable to the reserve categories noted below:

Year	Forecast Development Costs (M$) Proved Reserves	Proved Plus Probable Reserves
2023	7,933	8,361
2024	9,287	9,473
2024	0	0
Thereafter	3,829	3,829
Total Undiscounted	**21,049**	**21,663**
Total Discounted at 10%	**17,696**	**18,251**

Future development costs are capital expenditures required in the future for Razor to convert proved developed and undeveloped non-producing plus probable reserves to proved developed producing reserves. The undiscounted development costs are $21.1 million for proved reserves and $21.7 million for proved plus probable reserves, in each case based on forecast prices and costs.

On an ongoing basis, Razor will use internally generated cash flow from operations, debt and new equity issues, if available on favourable terms, to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for Razor.

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGEH. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered that proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable or production.

The following tables disclose, by each product type, the volumes of proved and probable undeveloped reserves that were first attributed by Sproule in each of the most recent three financial years.

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conv. Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2020	0	1,178	0	291	0	445	0	98	0	1,641
2021	0	1,315	0	223	0	657	0	74	0	1,721
2022	0	358	0	218	0	380	0	53	0	692

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conv. Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2020	0	831	0	87	0	158	0	104	0	1,048
2021	0	747	0	74	0	248	0	107	0	969
2022	0	114	0	71	0	126	0	16	0	222

As of December 31, 2022, undeveloped reserves represented 5 per cent of total proved reserves and 4 per cent of proved plus probable reserves. There are two vertical proved plus probable undeveloped Beaverhill Lake drilling locations in Swan Hills. There are five horizontal proved plus probable undeveloped locations in Southern Alberta in the Gluaconitic and Mannville formations.

Reserves were assigned adhering to the practices outlined within the COGEH, with uncertainty applied at the individual location level to account for the potential variability in well results.

The pace of development of the proved and probable undeveloped reserves is scheduled to start in 2023 to 2024. 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 or changing regulation and/or fiscal or environmental policy); (ii) program development may need to be spread over several years to optimize facility and pipeline utilizations; (iii) surface access issues (including weather conditions and regulatory approvals).

Other Oil and Gas Information

Principal Properties

Alberta

Swan Hills

The Swan Hills area is located in west central Alberta approximately 200 km northwest of Edmonton. As at December 31, 2022, the assets included 155,200 gross (132,112 net) acres of total land, of which 25,600 gross (21,447 net) acres were booked as undeveloped land. The assets at Swan Hills include 1,353 gross (863 net) wells in total, of which 225 gross (115 net) are producing wells. Production in the Swan Hills area is mainly from the legacy, large oil-in-place pools of the Swan Hills reef buildups of the Beaverhill Lake Group formation. Decline rates are predictable and low due to pressure support from existing waterflood schemes and further upside exists in optimization of existing floods, implementation of tertiary recovery schemes, reactivation of shut-in wells and drilling infill wells, both vertically and horizontally.

Oil and gas field production is gathered by flow lines to batteries and further transported by pipeline, and in certain limited areas by truck, to points of sale.

Kaybob

The Kaybob area is located in west central Alberta approximately 250 km northwest of Edmonton. As at December 31, 2022, the assets included 84,320 gross (42,494 net) acres of total land, of which 12,720 gross (4,783 net) acres were booked as undeveloped land. The assets at Kaybob include 240 gross (164 net) wells in total, of which 33 gross (22 net) are producing wells. The majority of wells produce light oil from the Montney formation. Activity on operated lands is focused on the highly permeable coquina interval of the Montney formation, including infill drilling, waterflood optimization, reactivation of shut-in wells and implementation of further enhanced oil recovery schemes.

Oil and gas field production is gathered by flow lines to batteries and further transported by pipeline, and in certain limited areas by truck, to points of sale.

District South

The District South area is located in Southern Alberta, approximately 250 km southeast of Calgary. As at December 31, 2022, the assets included 79,093 gross (57,549 net) acres of total land, of which 10,520 gross (6,801 net) were booked as undeveloped land. The assets include 519 gross (424 net) wells in total, of which 137 gross (109 net) are producing wells.

Production in District South is mainly from mature, well defined pools from the Lower Cretaceous era, consisting of both oil and gas deposits. Decline rates are low due to the mature nature of the pools. The oil pools have pressure support maintained through water injection, and the gas pools benefit from compression to maintain production. Upside exists in optimization of the existing water injection schemes, reactivation of shut-in wells, and pipeline and facility consolidation and optimization of the gas infrastructure.

Oil production is mainly gathered to operated oil batteries for processing. The finished product is primarily transported by sales pipeline but in some areas is trucked out for sale. Gas production is gathered and compressed in Razor operated pipelines and facilities, and then processed at a third-party facility.

End of Life Expenditures

The Company's non-producing wells range in status from suspended through to reclaimed and awaiting a reclamation certificate. The Company allocates a portion of its annual budget to end of life expenditures in order to progress wells to the next stage in their life cycle.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company had a working interest as at December 31, 2022. All of the wells were located onshore in the province of Alberta.

	Producing				Non-Producing (3)					
	Oil		Gas		Oil		Gas		Other	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Operated	110	105	85	79	690	634	95	68	287	259
Non-operated	171	55	29	8	294	94	122	66	229	83
Total	**281**	**160**	**114**	**87**	**984**	**728**	**217**	**134**	**516**	**342**

Notes:

(1) "Gross" means total number of wells in which Razor holds an interest.

(2) "Net" means the aggregate of the percentage working interests of Razor in the gross wells.

(3) "Other" means all other active and inactive non-producing wells, such as injection wells.

(4) "Non-Producing" means wells that are not operated or may not have been previously on production and the date production will be obtained from these wells is uncertain.

Razor has implemented an Inactive Well Management Program where all of its inactive wellbores are subject to a multidisciplinary review. This review establishes a plan for each wellbore, such as returning the well to production or injection, conducting end of life activities, or determining another use for the wellbore.

Properties with No Attributable Reserves

The following table summarizes the undeveloped land holdings (in acres) of the Company as at December 31, 2022.

	Undeveloped Acres		Developed Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	51,400	33,031	275,293	199,124	326,693	232,155
Total	**51,400**	**33,031**	**275,293**	**199,124**	**326,693**	**223,155**

Notes:

(1) "Gross" means the total number of acres in which Razor holds an interest.

(2) "Net" means the aggregate of the percentage working interests of Razor in the gross acres.

Razor expects that no rights to explore, develop and exploit undeveloped land holdings may expire by December 31, 2023. Razor closely monitors land expirations as compared to its development program with the strategy of minimizing undeveloped land expirations relating to significant identified opportunities. Razor does not anticipate any unusually high development, production or operating costs, any unusually high abandonment and reclamation costs, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations on properties with no contributed reserves. Other than commodity prices, there are no significant economic factors or significant uncertainties that affect the anticipated development or production activities on properties with no attributable reserves.

Forward Contracts and Marketing

From time to time, Razor enters into contracts to manage its exposure to fluctuations in commodity prices. A description of such contracts is provided in Razor's consolidated financial statements and accompanying Managements' Discussion and Analysis which can be found on SEDAR at www.sedar.com.

Tax Horizon

For the fiscal year end December 31, 2022, the Company paid no income tax and has approximately $144.0 million of tax pools available. Based on levels of production, commodity prices, acquisitions and capital expenditures, Razor does not expect to pay cash income taxes in the next five years.

Costs Incurred

The following table summarizes Razor's property acquisition costs, exploration costs and development costs for the year ended December 31, 2022.

Expenditure	Year Ended December 31, 2022 ($000s)
Property acquisition costs	-
Development costs	11,173
Other	-
Total	**11,173**

Exploration and Development Activities

See "*Principal Properties*" above for a description of Razor's exploration and development activities.

Production Estimates

The following table sets forth the volume of Razor's gross working interest production estimated for the year ending December 31, 2023, as evaluated by Sproule, which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data and Other Information*".

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	(BOE/d)
Proved					
Swan Hills	1,936	-	1,109	681	2,802
Kaybob	616	-	1,066	86	880
District South	154	132	1,235	14	506
Total Proved	**2,706**	**132**	**3,410**	**782**	**4,188**
Probable					
Swan Hills	43	-	17	17	63
Kaybob	10	-	24	2	16
District South	5	14	32	-	25
Total Probable	**58**	**14**	**72**	**19**	**103**
Total Proved plus Probable	**2,764**	**146**	**3,482**	**801**	**4,291**

Notes:

(1) Before deduction of royalties.

(2) Columns may not add due to rounding.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	2022 Quarter Ended				Year Ended
	Q4 Dec. 31	**Q3 Sept. 30**	**Q2 June 30**	**Q1 March 31**	**December 31 2022**
Average Daily Production[1]					
Light Oil (Bbls/d)	2,232	2,575	2,390	2,475	**2,418**
Heavy Oil (Bbls/d)	197	241	229	355	**255**
Natural gas liquids[2] (Bbls/d)	913	873	904	902	**898**
Conventional natural gas (Mcf/d)	3,098	4,948	4,907	4,350	**4,324**
Combined (BOE/d)	3,859	4,514	4,340	4,457	**4,291**
Average Daily Sales Volumes[1]					
Light Oil (Bbls/d)	2,245	2,592	2,373	2,645	**2,463**
Heavy Oil (Bbls/d)	203	239	224	231	**224**
Natural gas liquids[2] (Bbls/d)	913	873	904	902	**898**
Conventional natural gas (Mcf/d)	3,668	4,342	4,514	3,908	**4,107**
Combined (BOE/d)	3,972	4,428	4,253	4,429	**4,270**
Average Price Received					
Light Oil ($/Bbl)	108.05	115.22	133.56	120.22	**117.50**
Heavy Oil (Bbls/d)	88.61	100.40	124.46	68.21	**92.34**
Natural gas liquids ($/Bbl)	42.55	38.08	60.66	49.12	**49.47**
Conventional natural gas ($/Mcf)	5.34	5.26	7.26	4.95	**5.93**
Combined ($/BOE)	82.32	84.61	100.94	86.89	**88.65**
Royalties Paid[3]					
Light Oil ($/Bbl)	31.53	36.58	40.25	28.33	**33.71**
Heavy Oil (Bbls/d)	11.76	16.96	20.83	7.21	**13.44**
Natural gas liquids ($/Bbl)	10.10	13.83	15.27	14.13	**13.31**
Conventional natural gas ($/Mcf)	(1.39)	(0.87)	(0.51)	(1.37)	**(0.99)**
Combined ($/BOE)	20.12	23.49	25.87	17.81	**21.68**
Production Costs[3]					
Light Oil ($/Bbl)	53.30	44.47	38.27	34.59	**42.05**
Heavy Oil (Bbls/d)	132.67	100.80	106.53	95.77	**108.18**
Natural gas liquids ($/Bbl)	53.30	44.47	38.27	34.59	**42.05**
Conventional natural gas ($/Mcf)	8.88	7.41	6.38	5.76	**7.01**
Combined ($/BOE)	57.56	47.43	41.75	36.82	**45.18**
Netback Received[3][4]					
Light Oil ($/Bbl)	23.21	34.17	55.04	57.30	**41.75**
Heavy Oil (Bbls/d)	(55.81)	(17.36)	(2.91)	(34.77)	**(29.28)**
Natural gas liquids ($/Bbl)	(20.86)	(12.72)	7.12	0.40	**(10.35)**
Conventional natural gas ($/Mcf)	(1.17))	(1.92)	1.63	0.10	**(6.02)**
Combined ($/BOE)	4.50	14.04	33.60	31.84	**14.56**

Notes:

1) Before deduction of royalties. Production volumes are different than sales volumes in each quarter as the Company manages discretionary oil inventory builds in or draws in response to Light Sweet Edmonton Oil differentials compared to WTI.
2) Liquids include light and heavy oil and associated NGLs.
3) Razor did not record operating expenses on a commodity basis. Information in respect of operating expenses for oil ($/Bbl), natural gas liquids ($/Bbl) and natural gas ($/Mcf) has been determined by allocating expenses on a well-by-well basis based upon the relative volume of production of liquids and natural gas.
4) Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. Information in respect of netbacks received for oil ($/Bbl), natural gas liquids ($/Bbl) and natural gas ($/Mcf) is calculated using operating expense figures for oil ($/Bbl), natural gas liquids ($/Bbl) and natural gas ($/Mcf), which figures have been estimated.

The following table indicates the average daily production volumes for the year ended December 31, 2022 for each of the important properties comprising Razor's assets:

	Light, Medium & Heavy Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	(BOE/d)
Swan Hills	1,897	1,416	732	2,865
Kaybob	621	925	89	864
District South	264	1,657	22	562
Total	2,782	3,998	843	4,291

The average production for the year ended December 31, 2022 was 84% liquids; and for the year ended December 31, 2022, 94% of gross revenue was derived from liquids production.

INDUSTRY CONDITIONS

Overview

Companies operating in the crude oil and natural gas industry are subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada and Alberta, all of which should be carefully considered by investors in the crude oil and natural gas industry. It is not expected that any of these controls or regulations will affect the operations of Razor Energy Corp. in a manner materially different than they would affect other oil and natural gas producers of similar size. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Some of the principal aspects of legislation, regulations and agreements governing the crude oil and natural gas industry are described further in the commentary below.

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

MARKET CONDITIONS

Pricing and Marketing in Canada

Crude Oil

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

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("OPEC") forecasts robust growth in world oil demand in 2023, spurred by the relaxation of China's zero-COVID policy. OPEC predicts global oil demand to rise by 2.25 million barrels per day in 2023, despite newly emerging COVID-19 variants, interest rate increases in major economies and other uncertainties with respect to the world economy.

In February 2022, Russian military forces invaded Ukraine. Ongoing military conflict between Russia and Ukraine has significantly impacted the supply of oil and gas from the region. In addition, certain countries including Canada and the United States have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy in addition to the near term effects on Russia. The long-term impacts of the conflict remain uncertain.

Natural Gas

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

Natural Gas Liquids

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

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the National Energy Board Act (the "**NEB Act**") with the Canadian Energy Regulator Act (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Company does not directly enter into contracts to export its production outside of Canada.

Transportation Constraints and Market Access

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

Pipelines

Western Canada has seen significant growth in crude production volumes over recent years. This has resulted in pressure on the pipeline takeaway capacity, leading to apportionment on the main lines and, in turn, backed up local feeder pipelines. This has contributed to a widening of, and increased volatility in, the light oil pricing differential between West Texas Intermediate ("**WTI**") and Canadian Light Sweet Edmonton and the medium/heavy oil pricing differential between WTI and Cromer/WCS/Hardisty/ Edmonton. Although pipeline expansions are ongoing and producers are increasingly turning to rail as an alternative means of transportation, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market production. In addition, the prorationing of capacity on the interprovincial systems also continues to affect the ability to export oil and natural gas.

The Enbridge Inc. Line 3 Replacement from Hardisty, Alberta to Superior, Wisconsin came into service in October 2021. The Line 3 Replacement, originally expected to be in-service in late 2019, faced significant permitting difficulties in the United States, resulting in the two-year delay. The pipeline provides an incremental 370,000 bbls/d of export capacity from Western Canada into the United States.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the Federal Government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, the project budget has risen to $21.4 billion as of February 2023. The pipeline is expected to be in service it the third quarter of 2023, an extension from Trans Mountain's initial December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge filed a federal complaint in late November 2020 in the United States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shut-down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. In August 2022, the United States District Court for Western Michigan rejected the Attorney General of Michigan’s efforts to move the dispute to Michigan State Court, citing important federal interests at stake in having the dispute heard in federal court. Michigan’s Attorney General intends to appeal the decision.

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

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the Oil Tanker Moratorium Act, which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tones to or from British Columbia's north coast. The ban may prevent pipelines being built to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium.

Crude Oil and Bitumen by Rail

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020 that trains hauling more than 20 cars carrying dangerous goods, including oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in April 2020 and replaced in November 2020. The speed limits and other requirements established in Order MO 20-10 will remain in place until permanent rule changes are approved.

Natural Gas and LNG

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.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation (“TC Energy Corporation”) received federal approval to expand the NGTL System and the expanded NGTL System was completed in April 2022.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in Northeastern British Columbia to transport natural gas to the LNG

Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "CGL Pipeline"). Phase 1 of the LNG Canada project reached 70% completion in October 2022, with a completion target of 2025.

In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of November 2022, construction of the CGL Pipeline was approximately 80% complete. In addition to LNG Canada and the CGL Pipeline projects, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

GOVERNMENT REGULATIONS

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/USMCA

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 United States Mexico Canada Agreement (the "USMCA"), which replaced the former North American Free Trade Agreement ("NAFTA"), came into affect on July 1, 2020. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, the implementation of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Company's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. The USMCA does not contain the same proportionality requirements. The elimination of this clause removes a barrier in Canada's transition to a more diversified export portfolio and may allow more Canadian production to reach Eastern Canada, Asia, and Europe than was possible under NAFTA, subject to the construction of infrastructure.

Canada is also 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 including the Comprehensive Economic and Trade Agreement and the Comprehensive and Progressive Agreement for Trans-Pacific Partnership.

Land Tenure

Crude oil and natural gas rights located in the Western Canadian provinces are owned both by either the provincial governments (i.e. the Crown) or by private individuals. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Rights are granted pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or to make certain payments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied. In response to the COVID-19 pandemic, the government of Alberta announced measures to extend or continue Crown leases that may have otherwise expired in the months following the implementation of pandemic response measures. Where crude oil and natural gas is privately owned (i.e., freehold mineral lands), the rights to explore for and produce such crude oil and natural gas are granted by the issuance of a lease on such terms and conditions as may be negotiated.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. 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 for obtaining surface access to conduct operations that producers must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to the deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Alberta also has a policy of “shallow rights reversion” which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses.

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

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the Indian Oil and Gas Act (the **"IOGA"**) and the Indian Oil and Gas Regulations, 1995 (the "**"1995 Regulations**). In 2009, Parliament passed An Act to Amend the Indian Oil and Gas Act, amending and modernizing the IOGA (the **"Modernized IOGA"**), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the **"2019 Regulations"**). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. The Company has operations on Indian Oil & Gas Leases in the Jumpbush area of Alberta.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas, natural gas liquids ("NGLs") and sulphur production. Royalties payable on production from minerals other than Crown owned minerals are determined by negotiations between the mineral owner and the lessee although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the provincial governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving near-term earnings and cash flow within the industry. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

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

In addition, the federal government may from time to time provide incentives to the oil and natural gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, aimed to provide oil and natural gas businesses with eligible Canadian development expenses ("CDE") and Canadian oil and gas property expenses ("COGPE") with a first-year deduction of one and a half times the deduction that is otherwise available for CDE. The definitions of "accelerated CDE" and "accelerated COGPE", as amended in November 2018, allow oil and natural gas businesses to claim an additional 15% deduction for new CDE, and an additional 5% deduction for new COGPE for taxation years that end before 2024 if such CDE or COGPE was incurred after November 20, 2018. The acceleration is reduced to 7.5% for new CDE and 2.5% for new COGPE for taxation years that begin after 2023 and end before 2028. Successored expenses, and costs in respect of Canadian resource properties not acquired at arms' length, will not qualify for treatment as accelerated CDE or accelerated COGPE.

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

Alberta

In Alberta, oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation. The Mines and Minerals Act was amended in 2014 to shorten the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three.

On January 29, 2016, the Alberta government announced changes to the Alberta Royalty Framework. Under the new modern royalty framework (the "**MRF**"), the sliding scale royalty concept will be maintained, but will be achieved with a greater degree of simplicity. The new royalty percentage will be applied to the gross revenue generated from all hydrocarbons, with no differentiation between produced substances, and wells will be charged a flat 5% royalty rate until revenues exceed a normalized well cost allowance, which will be based on vertical well depth and lateral length. The calculation of this cost allowance, and other details regarding the various parameters within the new formula under the MRF was announced in 2016 and was fully implemented as of January 1, 2017. Prior to January 1, 2017, the former royalty framework continued to apply to any wells drilled prior to that date, and thereafter for a period of 10 years following which, such wells will be transitioned into the MRF. Any changes to the royalty regime in Alberta may have a material effect on the Company. See "*Risk Factors*".

In addition to any negotiated royalty amount payable to the freehold mineral owner, producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the Freehold

Mineral Rights Tax Act (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4 percent of revenues reported from fee simple mineral title properties.

Freehold and Other Types of Non-Crown Royalties

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

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights.

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

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 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 Company's operations and cash flow.

Federal

Canada is a signatory to the United Nations Framework Convention on Climate Change ("**UNFCCC**"), which was entered into in order work towards stabilizing atmospheric concentrations of greenhouse gas ("**GHG**") emissions at a level to prevent "dangerous anthropogenic interference with the climate system". The UNFCCC came into force on March 21, 1994. On December 12, 2015, the UNFCCC adopted the Paris Agreement, which Canada ratified on October 5, 2016. Under the Paris Agreement, countries have also committed to a goal of holding the increase in global average temperature to below 2°C above pre-industrial levels, while they pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. To date, 189 of the 197 parties to the convention have ratified the Paris Agreement.

In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC Secretariat, pledging a 30% reduction from 2005 levels - approximately 523 megatonnes - by 2030. The government also indicated, in a Speech from the Throne (also referred to as the "Throne Speech"; discussed in greater detail below) that it may implement policy changes to exceed this target. Specific details have not yet been announced.

In addition, provincial/territorial and federal leaders met and agreed that they would work together to build a national climate change plan. At a follow-up meeting of the First Ministers and Prime Minister on March 3, 2016, the parties agreed under the

Vancouver Declaration on Clean Growth and Climate Change to launch a process to develop the Pan-Canadian Framework on Clean Growth and Climate Change that set out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollutions Pricing Act (the **"GGPPA"**), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of carbon dioxide equivalent ("CO2e") emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. Under this Framework, the federal government has set a minimum price on carbon starting at $10 per tonne of CO2e in 2018, which will increase by $10 per year until it reaches $50 per tonne of CO2e by 2022. 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 CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Under the federal plan, each province and territory were required to implement carbon pricing in its jurisdiction by 2018, whether in the form of a carbon tax or a cap-and-trade system. If the carbon price in a jurisdiction does not meet the federal minimum price, the federal government will step in and impose a carbon price that makes up the difference and return the revenue to the province or territory. In addition, provincial and territorial goals for reducing emissions must be at least as stringent as federal targets. Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to the Supreme Court of Canada. The hearing took place in September 2020. The Court ruled against these provinces in March 2021.

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

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 intended to support pollution reduction initiatives, including methane. Funds disbursed through this program will primarily take the form of repayable contributions to onshore and offshore oil and gas firms.

Draft Clean Fuel Standard regulations were released in December 2020. Unlike the earlier proposed regulatory framework, the draft regulations apply to liquid fuels only. On June 20, 2022, the final Clean Fuel Regulations were published and came into force. The regulations will require producers or importers of gasoline, diesel, kerosene, and light and heavy fuels oils to reduce the carbon intensity of the fuels it produces or imports. The carbon intensity requirements for these regulations will become more stringent over time.

In the September 23, 2020 Throne Speech, the federal government indicated that it intends to make a number of investments that will help it achieve net-zero emissions by 2050, including investments intended to: (i) improve transit options; (ii) make zero-emissions vehicles more affordable; (iii) expand electric vehicle charging infrastructure across the country; (iv) launch a fund that will help attract investments in the development of zero-emissions technology, including a corporate tax cut of 50%

for companies participating in this initiative; (v) develop a Clean Power Fund that will, in part, help regions transition to cleaner sources of power generation; and (vi) support continued investment in the development and implementation of renewable and clean energy technologies. Specific program details have not yet been announced.

On November 19, 2020, the federal government introduced the Canadian Net-Zero Emissions Accountability Act in Parliament and it became law on June 29, 2021. The Act binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It will also establish rolling five-year emissions-reduction targets and require the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body and require the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making. On March 29, 2023, The Minister of Environment and Climate Change announced Canada's 2030 Emissions Reduction Plan. The plan sets to cut emissions by 40% from 2005 levels by 2030, with the ultimate goal of net-zero emissions by 2050.

Alberta

In June 2019, the federal fuel charge took effect in Alberta. In accordance with the GGPPA, on April 1, 2023 the fuel charge payable in Alberta increased from \$50 to \$65/tonne of CO2e and will continue to increase at a rate of \$15 per year until it reaches \$170/tonne of CO2e in 2030.In December 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous Carbon Competitiveness Incentives Regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000-tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these Directives will support Alberta in achieving its 2025 goal. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

Environmental Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to evolving national, provincial and municipal laws and regulations, as well as, potentially, international conventions. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced in association with oil and gas operations, habitat protection and minimum setbacks of oil and gas activities from freshwater bodies. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines, penalties and sanctions, some of which may be material or materially affect the Company's operations. Certain environmental protection legislation may subject the Company to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault need not be established by claimants affected by such a spill or discharge. Further, as Canadian environmental legislation evolves, the use of administrative penalties by the imposition of fines for the commission of environmental offences on an absolute liability basis has grown.

Environmental legislation is evolving in a manner that has and is expected to continue to result in stricter standards and enforcement, larger fines, liabilities and sanctions, and potentially increased capital expenditures and operating costs. To mitigate potential environmental liabilities, the Company, in addition to implementing policies and procedures designed to prevent an accidental spill or discharge, maintains insurance at industry standards.

Federal

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

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

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

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the Impact Assessment Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the Impact Assessment 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. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA, but this matter remains before the courts.

In May 2022, the Alberta Court of Appeal released its decision 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.

Alberta

The discharge of oil, natural gas, or other pollutants into the air, soil or water may give rise to liabilities to third parties and may require the Company to incur costs to remedy such discharge in the event that they are not covered by the Company's insurance. Although the Company maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* (**"EPEA"**), the *Water Act* and the *Oil and Gas Conservation Act* (**"OGCA"**). The EPEA and the OGCA impose strict environmental standards with respect to releases of effluents and emissions, require stringent compliance, reporting and monitoring obligations, and impose significant penalties for non-compliance.

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the *Alberta Energy Regulator* (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the OGCA. On November 30, 2013, the AER assumed the energy related functions and responsibilities of *Alberta Environment and Parks* ("**AEP**") in respect of the disposition and management of public lands under the Public Lands Act. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AEP in the areas of environment and water under EPEA and the Water Act, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The oil and gas industry is subject to such environmental regulations which include restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and natural gas production. The Company may conduct hydraulic fracturing in its drilling and completion programs. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further. The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of induced seismicity is higher and implemented the requirements in Subsurface Order 44 Nos. 2, 6, and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "Seismic Protocol Regions"). The Company has not conducted operations in the Seismic Protocol Regions.

The Company believes it is in material compliance with environmental legislation in the jurisdictions in which it operates at this time. The Company's practice is to do all that it reasonably can to ensure that it remains in material compliance with environmental protection legislation. The Company also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation.

No assurance can be given that environmental laws will not result in a curtailment of production, a material increase in the costs of production or the costs of development or exploration activities, or otherwise adversely affect the Company's financial condition, capital expenditures, results of operations, competitive position or prospects.

Liability Management Rating Program

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* in an urgent response to a decision from the Alberta Court of Queen's Bench, which was affirmed by a majority at the Alberta Court of Appeal. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the *Oil and Gas Conservation Act (Alberta)* and the *Bankruptcy and Insolvency Act ("**BIA**")*, and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA.

On January 31, 2019, the Supreme Court of Canada ruled on the appeal of Redwater in *Orphan Well Association v. Grant Thornton Limited*, 2019 SCC 5 in favour of the AER and Orphan Well Association. Specifically, the SCC held that while trustees will not be personally liable for abandonment and reclamation obligations, the estate will remain liable for such obligations. As a result, reclamation and abandonment liabilities must be dealt with before there can be any distribution to the insolvent parties' creditors, including its secured creditors.

In response to the SCC's decision in *Redwater*, the AER began working on an improved liability management framework. On July 30, 2020, the Government of Alberta announced that it will introduce a new Liability Management Framework ("**LMF**") for the oil and gas industry which is intended to replace the Alberta Liability Management Program (the "**LMR Program**"). The LMF is intended to implement a holistic and full lifecycle approach to reclamation and remediation obligations. Since the announcement, the Government of Alberta has gradually begun to phase-in the LMF through legislative and AER directive amendments.

Prior to the change, the AER administered the Licensee Liability Rating Program (the "**AB LLR Program**") as part of the Liability Management Rating Assessment Process. The AB LLR Program was a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The AB LLR Program required a licensee whose deemed liabilities exceed its deemed assets (and therefore the licensee has a resulting in a license liability rating ("**LLR**") of less than 1.0) to provide the AER with a security deposit. In certain circumstances, for example during the transfer of AER licenses between parties, the AER required that the transferee must achieve an LLR of 2.0 or higher immediately following the proposed transfer of the applicable licenses. The ratio of deemed liabilities to deemed assets was assessed once each month and upon the submission of a license transfer application, and failure to post the required security deposit could result in the initiation of enforcement actions by the AER.

The ABOGCA established an Orphan Fund which is run by the Orphan Well Association ("**OWA**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licencee or working interest participant becomes insolvent or is unable to meet its obligations. The OWA is an industry-funded, non-profit organization that operates under authority given by the AER. In April 2020, the Government of Alberta passed Bill 12: the *Liabilities Management Statutes Amendment Act* (the "**LMSAA**"), which came into force on proclamation. The LMSAA places the burden of a defunct licencees' abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the orphan fund (the "**Orphan Fund**") to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

Under the LMF, the OWA will have broader authority to assist in the reclamation and remediation of wells, facilities and pipelines. The Orphan Fund was originally intended to be funded exclusively by licencees in the AB LLR Program and Alberta Oilfield Waste Liability Program (the "**AB OWL Program**") who contributed to a levy administered by the AER. However, the Government of Alberta has loaned the Orphan Fund approximately $355 million. The Government has also covered $113 million in levy payments that licencees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. Collectively, these programs were designed to minimize the risk of the Orphan Fund posed by the unfunded liabilities of licencees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

In April 2020, the federal government also announced that up to $1 billion in funding would be available to Alberta’s oilfield service contractors to perform reclamation work as part of the federal government’s COVID-19 Economic Response Plan and $200 million would be offered to the OWA as a repayable loan. In May 2020, the Government of Alberta launched the site rehabilitation program which was funded primarily by the federal government’s COVID-19 Economic Response Plan. Pursuant to the program, contractors are provided with grants to perform well, pipeline and oil and gas site closure and reclamation work. The Government of Alberta also announced the extension of a $100 million repayable loan to the OWA.

The Government of Alberta has said the LMF is expected to address five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) licencee capability assessment system to provide proactive support through ongoing financial capability review; (iii) mandatory spend targets to support inventory reduction; (iv) a process to address legacy and post-closure sites or sites that were remediated, reclaimed or abandoned prior to the LMF; and (v) the OWA taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure.

On December 1, 2021, the Government of Alberta announced amendments to Directive 006: *Licensee Liability Rating (LLR) Program* and a new Directive 008: *Licensee Life-Cycle Management*. A new Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* was also introduced in April 2021 which introduces new criteria for the AER to consider whether an applicant, licencee or approval holder poses an "unreasonable risk". Among other changes under the LMF, the AB LLR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the LMF will also provide proactive support to distressed operators and will require companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the LMF, each licencee will be required to meet mandatory annual spend targets for well closures and abandonments starting January 2022.

The AER in 2015 also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: *Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applied to all inactive wells that were noncompliant with Directive 013 as of April 1, 2015. The objective was to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licencee was required to bring 20 percent of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: *Well Abandonment*. The compliance deadline for the final year of the IWCP was extended from April 1, 2020 to September 1, 2020 and was concluded in March 2021.

On April 7 2021, the ARE amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals which deals with the eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings. The amendments include an annual financial reporting obligation, the expansion of factors the AER may consider in assessing whether an applicant, licensee, or approval holder poses an unreasonable risk, and an obligation for the licensee to notify the ARE in the case of default on a debt or a significant change to their working interest participant arrangements. Pursuant to Directive 067, the AER may revoke or restrict a company's eligibility to hold AER licences if the AER determines that the licensee poses an "unreasonable risk", taking into account a broad range of financial and operational considerations.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER has also announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Participants seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The ABC, together with the inventory reduction program implemented under the LMF, which implements mandatory closure spend targets over a 5-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

The implementation of the LMF is still ongoing with the AER having released updates during 2022.The expectation is the LMF will replace the AB LMR Program in its entirety, however, such transition will require time as the AB LMR Program is integrated throughout the regulatory regime including Directives and legislation. No timeline has been committed to for the implementation of the LMF, however, implementation will likely continue throughout 2023, with the gradual and phasing changes to legislative, regulatory and AER directives in order to adequately implement and integrate the LMF.40

The Company cannot predict what the LMF may look like but the implementation of the LMF and the new regulatory framework will have an impact on crude oil and natural gas production in Alberta, including Razor's business.

RISK FACTORS

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

Overview

The Company's business consists of the exploration and production of crude oil and natural gas projects, with producing properties in the province of Alberta. There are a number of inherent risks associated with the exploration and production of oil and gas reserves. Many of these risks are beyond the control of the Company.

Nature of Business

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

Difficulty Implementing Business Strategy

The growth and expansion of the Company is heavily dependent upon the successful implementation of its business strategy. There can be no assurance that the Company will be successful in the implementation of its business strategy.

Commodity Price Volatility

Razor's results of operations and financial condition are dependent on the prevailing prices of crude oil and natural gas. Crude oil and natural gas prices have fluctuated widely in the recent past and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond the Company's control. Crude oil and natural gas prices are impacted by a number of factors including, but not limited to: the global supply of and demand for crude oil and natural gas; global economic conditions; the actions of the Organization of Petroleum Exporting Countries ("**OPEC**") and OPEC+; government regulation; political stability and geopolitical factors; the ability to transport crude to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. In March 2020, global oil prices weakened materially as a result of the COVID-19 pandemic, compounded by OPEC+, led by Saudi Arabia and Russia, failing to reach an agreement on constraining output. Concerns over global economic conditions, fluctuations in interest rates and foreign exchange rates, stock market volatility, energy costs, geopolitical issues, OPEC+ actions, inflation, the availability and cost of credit, the deceleration of economic growth in the People's Republic of China, trade disputes between the United States and the People's Republic of China, civil unrest in Venezuela and Iran and the outbreak of COVID-19 have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, significant growth in crude production volumes in Western Canada and the northern United States has resulted in pressure on transportation and pipeline capacity, contributing to the widening of the light oil pricing differential between WTI and Cromer/Hardisty/ Edmonton, resulting in fluctuations in the price of oil and natural gas. Oil and natural gas producers in Western Canada may receive significantly discounted prices for some of their production due to regional constraints on their ability to transport and sell such production. All of these factors are beyond the Company's control and can result in a high degree of price volatility.

Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in United States dollars, are stated in Canadian dollars. The Company's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between the Company's light oil (in particular the light differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, but they are also influenced by other factors such as transportation costs, capacity and interruptions; refining demand; and the quality of the oil produced, all of which are beyond Razor's control. See also "*Variations in Foreign Exchange Rates and Interest Rates*".

Fluctuations in the price of commodities and associated price differentials may impact the value of Razor's assets and the ability to maintain its business and to fund growth projects. Prolonged periods of commodity price depression and volatility may also negatively impact the Company's ability to meet guidance targets and meet all of its financial obligations as they come due. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations, prospects and the level of expenditures for the development of oil and natural gas reserves, including delay or cancellation of existing or future drilling or development programs or curtailment in production.

Any material or sustained decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Company's reserves. Razor might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities.

Crude oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC+ actions and ongoing military actions between Russia and Ukraine. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and 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 Company may, in part, be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid.

Razor conducts regular assessments of the carrying value of its assets in accordance with IFRS. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying value of the Company's assets may be subject to impairment.

Ability to Continue as a Going Concern

As at December 31, 2022, the Company has a working capital deficit of $125.3 million and contractual obligations of $164.0 million due in less than one year. The Company has $2.4 million of cash and cash equivalents as at December 31, 2022.

Further, as at December 31, 2022, the Company, although having received a waiver in advance of year-end for a potential default of certain financial covenants under the AIMCo Term Loan, had a cross-default covenant violation, as a result of being in default of certain non-financial covenants under the Arena Amended and Restated Term Loan regarding the minimum production requirement allowing the lenders to demand repayment. As a result, amounts outstanding under the AIMCo Term Loan and the Arena Amended and Restated Term Loan have been presented as a current liability. The defaults noted above also triggered a cross covenant default on certain equipment loans and leases resulting in these loans and leases being potentially due on demand and classified as a current liability as at December 31, 2022.

Subsequent to year-end, the Company has executed a debt settlement agreement with AIMCo and obtained a waiver from the lender for the Arena Amended and Restated Term Loan. The Company is also undertaking a Rights Offering on a best-efforts basis for up to $10 million. There is no certainty that the Rights Offering will be successful in raising any additional cash. The completion of these transactions are subject to the satisfaction of a number of conditions to which there is no certainty.

The Company is currently in discussions with the third parties under the equipment loans and leases, to attempt to remediate all events of default however, there can be no assurance that the Company will be successful in obtaining amendments or waivers under those agreements.

Although, these arrangements have the potential to alleviate some of the working capital deficit and contractual obligations for the 2023 year, the Company will be reliant on the support of lenders, suppliers and other providers to the Company, as forecasted cash flow from operations is not sufficient to enable the Company to address the remaining working capital deficit and contractual obligations that will be significant, and the Company will need to maintain production levels above the minimum level required to avoid a future event of default under the Arena Amended and Restated Term Loan.

Due to the conditions noted above there remains material uncertainties that create significant doubt with respect to the Company’s ability to meet its obligations as they come due and, therefore, it may be unable to realize its assets and discharge its liabilities in the normal course of business.

The audited consolidated financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business. The audited consolidated financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern basis were not appropriate for the audited consolidated financial statements, then adjustments would be necessary in the carrying value of the assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

COVID-19

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide could have an adverse impact on Razor’s business, including changes to the way we and our counterparties operate, and on our financial results and condition. The spread of the COVID-19 pandemic, given its severity and scale, continues to pose risks to the global economy and the petroleum and natural gas industry more broadly. While a number of containment measures have been and continue to be gradually eased or lifted across some regions, additional safety precautions and operating protocols aimed at containing the spread of COVID-19 have been and continue to be instituted in line with guidance of public health authorities. As the impacts of the COVID-19 pandemic continue to materialize, the prolonged effects of the disruption have had and continue to have adverse impacts on Razor's business strategies and initiatives, resulting in ongoing effects to our financial results, including the increase of counterparty, market and operational risks.

The COVID-19 pandemic has resulted, and may continue to result, in disruptions to some of Razor's business partners, clients and customers and the way in which we conduct our business, including prolonged duration of staff working from home. These factors have impacted, and may continue to impact, our business operations and continuity of relationships with our business partners. Operational risks which may affect the Company or our business partners include the need to provide enhanced safety measures for employees and customers; complying with rapidly changing regulatory guidance; addressing the risks of attempted fraudulent activity and cybersecurity threat behavior; and protecting the integrity and functionality of the Company's systems, networks and data as a larger number of employees work remotely. It remains uncertain how the macroeconomic environment will be impacted following the COVID-19 pandemic. Unexpected developments in commodity and financial markets, regulatory environments, industrial activity or consumer behavior and confidence may also have adverse impacts on the Corporation's business and financial condition, potentially for a substantial period of time.

Gathering and Processing Facilities, Pipeline Systems and Rail

The amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of 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 could result in the inability to realize the full economic potential of the Company's production or in a reduction of the price offered for its production. The lack of firm pipeline capacity, production limits and limits on availability of capital in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil, NGL and natural gas to market. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Company's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, its financial condition, operations and cash flows. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In August 2019, the Canadian Energy Regulator Act and the Impact Assessment Act came into force, resulting in changes to the federal regulation and associated environmental assessments of major projects. See "*Industry Conditions – Environmental Protection Requirements*". The impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

In January 2021, U.S. President Biden revoked the permit for the Keystone XL Pipeline. As a result of the revocation, and following a comprehensive assessment of its options and consulting with its partners and stakeholders, including the Government of Alberta, on June 8, 2021, TC Energy terminated the Keystone XL Pipeline project.

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

Capital Lending Markets

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Company may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities as well as the repayment of outstanding debt. As a result of recent global and economic uncertainties in the oil and natural gas industry and, in particular, the lack of risk capital available to the junior resource sector, the Company, along with other junior resource entities, may have reduced access to bank debt and to equity. As future capital expenditures will be financed out of funds generated from operations, bank borrowings, if available, and possible issuances of debt or equity securities, the Company's ability to fund future capital expenditures is dependent on, among other factors, the overall state of lending and capital markets and investor and lender appetite for investments in the energy industry, generally, and the Company's securities in particular.

To the extent that external sources of capital become limited, unavailable or available only on onerous terms, the Company's ability to invest and to 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.

Markets and Marketing

The marketability and price of crude oil and natural gas that may be acquired or discovered by the Company is, and will continue to be, affected by numerous factors beyond its control. Razor's ability to market its crude oil, NGL and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Razor may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines, railway lines and processing and storage facilities and operational problems affecting such pipelines, railway lines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Exploration and Production Risks

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

Future oil, NGL and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, 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 but are not limited to 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 close well supervision, effective maintenance operations and the development of enhanced recovery technologies 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.

In addition, oil and gas exploration, development and production operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow outs, cratering, sour gas releases, fires, explosion, spills or leaks. These risks could result in personal injury, loss of life, and environmental or property damage. Particularly, the Company may explore for and produce sour gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

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

As is standard industry practice, the Company is not fully insured against all risks, nor are all risks insurable. Although the Company maintains liability insurance and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Risk Factors – Insurance*". In either event, the Company could incur significant costs.

Weakness and Volatility in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, actions or inaction taken by the Organization of the Petroleum Exporting Countries ("**OPEC**") and OPEC+, announcements by Saudi Arabia to relax quotas and resulting price wars, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakened global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including a growing anti-fossil fuel sentiment and the continuing impact of the Coronavirus ("**COVID-19**"), See "*Risk Factors – Political Uncertainty*" and "*Risk Factors – COVID-19*", have caused significant weakness and volatility in commodity prices. ". These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or may be implemented by governments at the federal and provincial levels. See "*Risk Factors – Fiscal and Royalties Regimes*", "*Risk Factors – Regulatory* " and "*Risk Factors – Chronic Climate Change Risks*" In addition, the difficulties encountered by midstream proponents to obtain on a timely basis or continue to maintain the necessary approvals to build pipelines, LNG plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. The resulting price differential between Western Canadian Select crude oil and

Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of the Company's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, the Company's cash flow resulting in a reduced capital expenditure budget. Consequently, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year over year basis. See "*Risk Factors - Reserves and Resource Estimates*". In addition to possibly decreasing the value of the Company's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Company's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Company's oil, NGL and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement.

Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Company may have difficulty raising additional funds or, if it is able to do so, it may be on unfavourable and highly dilutive terms. See "*Risk Factors – Additional Funding Requirements*". If these conditions persist, the Company's cash flow may not be sufficient to continue to fund its operations and satisfy its obligations when due, and the Company's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all to the Company. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge its obligations and continue as a going concern.

Legal Proceedings

In the normal course of the Company'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, related to personal injuries, including resulting from exposure to hazardous substances, property damage, property tax, 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 Company and as a result, could have a material adverse effect on the Company's assets, liabilities, business, financial condition and results of operations. Even if the Company prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Company's financial condition.

The Company is named as a defendant in legal proceedings. See "*Legal Proceedings and Regulatory Actions*". While management of the Company does not believe that these actions will have a material effect on the business or financial condition of the Company, no assurance can be given as to the final outcome of this or any other legal proceedings or that the ultimate resolution of this or any other legal proceedings will not have a material adverse effect on the Company.

In the event that the actions would be determined in a manner adverse to the Company, it could have a material adverse effect on the Company's business, financial condition and results of operations.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During its tenure, the former American administration has withdrawn from The Comprehensive and Progressive Agreement for Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected competitiveness of other jurisdictions, including Canada.

In addition, NAFTA has been renegotiated and on December 10, 2019, Canada, the U.S. and Mexico signed the USMCA, which has subsequently been ratified by the three signatory countries. See "Industry Conditions - *The North American Free Trade Agreement and Other Trade Agreements*".

The Biden administration in the U.S. has indicated that it will roll-back certain policies of the former administration and has revoked TC Energy's Keystone XL pipeline permit. While it is unclear which other legislation or policies of the former Trump administration will be rolled-back and if such rollbacks will be a priority of the new administration in light of the ongoing COVID-19 pandemic, any future actions taken by the new U.S. administration could have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Company.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union are slowly emerging and some impacts may not become apparent for some time. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on the Company's ability to market products internationally, increase costs for goods and services required for operations, reduce access to skilled labour and negatively impact business, operations, financial conditions and the market value of the Common Shares.

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

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

The federal Government was re-elected in 2021, but in another minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry. See "*Government Regulations – Climate Change Regulation*", " *Industry Conditions – Transportation Constraints and Market Access* " and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

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 Company's activities. See "*Industry Conditions – Transportation Constraints and Market Access* ".

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, geographical location, field discovery data and the type or quality of the petroleum product produced. See "*Industry Conditions*".

The royalty regime in Alberta, and any other jurisdictions in which the Company's oil and natural gas assets are located, may be subject to further review and changes which could adversely impact the Company's financial condition and operations. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic.

Changes in Legislation

It is possible that the Canadian federal and provincial government or regulatory authorities could choose to change the Canadian federal income tax laws, royalty regimes, liability management, environmental and climate change laws or other laws applicable to oil and gas companies and that any such changes could materially adversely affect the Company, its shareholders and the market value of the Common Shares.

Regulatory

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, either of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Further, the ongoing third-party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See "*Industry Conditions –Climate Change Regulations*", "*Industry Conditions – Transportation Constraints and Market Access*" and "*Risk Factors – Liability Management*".

In order to conduct oil and natural gas operations, the Company 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 Company 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 Company's business, financial condition and the market value of its common shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions –Liability Management Rating Program*".

Insurance

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

Non-Governmental Organizations

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

Reputational Risk Associated with the Company's Operations

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

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

Project Risks

The Company will manage and participate in a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Project cost estimates may not be accurate due to a lack of history of comparable projects. Furthermore, significant project cost over-runs could make a project uneconomic.

The Company's ability to execute projects and market oil, NGL and natural gas will depend upon numerous factors beyond the Company's control, including: the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of storage capacity; the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations; the supply of and demand for oil, NGL and natural gas; the availability of alternative fuel sources; the effects of inclement and severe weather events including fire, drought, extreme cold and flooding; the availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; changes in regulations; the availability and productivity of skilled labour; and the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company 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.

Substantial Capital Requirements and Liquidity

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

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

See "Industry Conditions – Provincial Royalties and Incentives".

If its future revenues or reserves decline, the Company 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 flow from 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 Company. Moreover, future activities may require the Company to alter its capitalization significantly. The inability of the Company to access sufficient capital for its operations could have material adverse effect on the Company's financial condition, results of operations or prospects.

Competition

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

Cost of New Technologies

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil, NGL 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. The Company’s actual interest in properties may vary from its records. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Company’s business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties the Company controls that, if successful or made into law, could impair the Company’s activities on them and result in a reduction of the revenue received by the Company.

Environmental Risks

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 international conventions and federal, provincial and municipal 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 spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation includes 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. See "*Industry Conditions*

– *Exports from Canada*", "*Industry Conditions –Environmental Protection Requirements*" and "*Industry Conditions – Climate Change Regulation*".

Compliance with such legislation can require significant expenditures and a breach 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 Company to incur costs to remedy such discharge. Although the Company believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that the application of environmental laws to the business and operations of the Company will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids resources, reserves and cash flows to be derived therefrom, including many factors beyond the Company's control. In estimating reserves, the chance of commerciality is effectively 100%. For prospective resources, the chance of commerciality will be the product of the chance that a project will result in a discovery of petroleum or natural gas and the chance that an accumulation will be commercially developed. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

The reserve and associated cash flow information and estimates represent 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, NGL's and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results.

For those reasons, estimates of the economically recoverable oil, NGL 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 expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Company'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. Further, the evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

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 are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Company'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 revenue from the Company's assets will be affected by other factors such as actual production levels, supply and demand for oil, NGL and natural gas, curtailments or increases in consumption by oil, NGL and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and revenues derived therefrom will vary from the estimates, and such variations could be material.

Geological risking of prospective resources addresses the probability of success for the discovery of petroleum; this risk analysis is conducted independently of probabilistic estimates of petroleum volumes and without regard to the chance of development. Principal risk elements of the petroleum system include: (i) trap and seal characteristics; (ii) reservoir presence and quality; (iii) source rock capacity, quality and maturity; and (iv) timing, migration and preservation of petroleum in relation to trap and seal formation. Geological risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators.

Reserve Replacement

The Company's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on the Company successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in its reserves will depend not only on the Company'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 Company's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Finding, Developing and Acquiring Petroleum and Natural Gas Reserves on an Economic Basis

Petroleum and natural gas reserves naturally deplete as they are produced over time. The success of the Company's business is highly dependent on its ability to acquire and/or discover new reserves in a cost-efficient manner. Substantially all of the Company's cash flow is derived from the sale of the petroleum and natural gas reserves it accumulates and develops. In order to remain financially viable, the Company must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. The Company mitigates this risk by employing a qualified and experienced team of petroleum and natural gas professionals, operating in geological areas in which prospects are well understood by management and by closely monitoring the capital expenditures made for the purposes of increasing its petroleum and natural gas reserves.

Liability Management

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. See "*Industry Conditions – Liability Management Rating Program*".

Whether under the AB LMR Program or the new LMF, the liability management system may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The impact and consequences of the Supreme Court of Canada in the Redwater case on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings will continue to evolve as the decision is evaluated and as the AER continues its phased implementation of the new LMF.

Income Taxes

The Company files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, 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 Company. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company 's detriment.

Chronic Climate Change Risks

The Company's exploration and production facilities and other operations and activities emit GHGs and which may require the Company to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place.

The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

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

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In recent years, climate change advocacy groups have attempted to bring legal action against various levels of government for climate related change.

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

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and forest fires may restrict the Company's ability to access its properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Company's assets are located in locations that are proximate to forests and rivers and as such a forest fire or flood may lead to significant downtime and/or damage to such assets.

Moreover, extreme weather conditions may lead to disruptions in the Company's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company makes acquisitions and dispositions of businesses and assets that occur 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 realizing the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of individual properties and other assets. In this regard, non-core assets are periodically disposed of, so that the Company 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 Company, if disposed of, could realize less than their carrying amount on the financial statements of the Company.

Operational Dependence

Other companies operate some of the assets in which the Company has an interest. As a result, the Company will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect its financial performance. The Company's return on assets operated by others will therefore depend upon a number of factors that may be outside of its 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.

Reliance on Key Personnel

The operations and management of the Company require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key person insurance in effect. The contributions of the existing management team to the Company's immediate and near-term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the Company's management. If the Company is unable to: retain current employees; and/or recruit new employees with the requisite knowledge and experience, it could be negatively impacted. In addition, the Company could experience increased costs to retain and recruit these professionals.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company 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 Company to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licences and Leases

The Company's properties are held in the form of licences and leases and working interests in licences and leases. If the Company 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 Company'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 Company's results of operations and business.

Permits and Licences

The operations of the Company may require licences and permits from various governmental authorities. There can be no assurance that the Company will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its properties.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Company may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Company's cash flow from operations and current cash balance is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favorable terms.

Current conditions in the oil and natural gas industry have had a negative impact on the ability of oil and natural gas companies in Canada to access additional financing and has increased the cost of existing financing.

Dividends

The amount of future cash dividends paid by the Company, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends.

Additional Taxation Applicable to Dividends Paid to Non-Residents

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. Where a non-resident is a United States resident entitled to benefits of the Canada - United States Income Tax Convention, 1980 and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%.

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/United States dollar exchange rate, which will fluctuate over time. Future Canadian/United States exchange rates could accordingly impact the future value of the Company’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 Company receives for its oil, NGL and natural gas production, it could also result in an increase in the price for certain goods used for the Company's operations, which may have a negative impact on the Company's financial results.

Furthermore, an increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the common shares of the Company.

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

Issuance of Debt

From time to time, the Company may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may increase the Company’s debt levels above industry standards. Neither the Company’s articles of incorporation nor its by-laws limit the amount of indebtedness that it may incur. The level of the Company’s indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. The Company’s ability to meet its debt service obligations will depend on the Company’s future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of the Company. As certain of the indebtedness of the Company could bear interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase the Company's interest payment obligations and could have a material adverse effect on its financial condition and results of operations. Further, its indebtedness would be secured by substantially all of the Company's assets. In the event of a violation by the Company of any of its loan covenants or any other default on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable and, in certain cases, foreclose on the Company's assets. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Hedging

From time to time, the Company uses financial instruments and physical delivery agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company may not benefit from such increases. In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

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

Similarly, from time to time the Company 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 Company will not benefit from its fluctuating exchange rate.

Availability of Drilling Equipment and Access Restrictions

Oil and natural gas exploration, development and operating 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. An increase in demand or cost for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development and operating activities.

Information Technology Systems and Cyber-Security

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

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of its information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware. The ongoing COVID-19 pandemic has increased the Company's cyber-attacks, as increased malicious activities are creating more threats for cyberattacks including COVID-19 phishing emails, malware-embedded mobile apps that purport to track infection rates and targeting of vulnerabilities in remote access platforms as many companies continue to operate with work from home arrangements.

The Company maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts cyber-security risk assessments. Despite the Company's efforts to mitigate such cyber-attacks through education and training, cyber-phishing activities remain a serious problem that could potentially damage its information technology infrastructure. The Company has technical and process controls in line with industry-accepted standards to protect its information assets and systems; however, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation, and any damages sustained may not be adequately covered by the Company's current insurance coverage, or at all. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Company’s business, financial condition and results of operations.

Aboriginal Claims

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

On December 3, 2020, the federal Government introduced Bill C-15, An act respecting the United Nations Declaration on the Rights of Indigenous Peoples which requires the Federal Government to ensure all Canadian laws are consistent with UNDRIP, implement an action plan to achieve UNDRIP’s objectives and table a report on the process of aligning the laws of Canada and on the action plan. On June 21, 2021 Bill C-15 received Royal Assent and came immediately into force. Additional processes may be created or legislation amended or introduced associated with projected development and operations, further increasing uncertainty with respect to project regulatory approval timeline and requirements.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of this Company. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company'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 Company 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.

Conflicts of Interest

Directors and officers of the Company may also be directors and officers of other oil and gas companies involved in oil and gas exploration and development, and conflicts of interest may arise between their duties as officers and directors of the Company and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with and are subject to such other procedures and remedies as apply under the ABCA. See "*Directors and Officers – Conflicts of Interest*."

Dilution

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

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. 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. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of the Company's exploration and development activities, which could in turn have a material adverse impact on the Company's business, operations and prospects.

Third Party Credit Risk

The Company is, or may be, exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Company may be exposed to third party credit risk from operators of properties in which the Company has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company and its cash flow from operations. 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 Company's ongoing capital program, potentially delaying the program and the results of such program until the Company 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 Company being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's financial and operational results.

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 crude oil, natural gas and other liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. The Company 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 Company’s business, financial condition, results of operations and cash flows by decreasing the Company's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Waterflood

The Company may undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities Razor needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Company will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Company is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs. In addition, the Company may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Company’s results of operations.

Expansion into New Activities

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

Changing Investor Sentiment

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

Forward-Looking Information may Prove to be Inaccurate

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

Additional information on the risks, assumptions and uncertainties are found in this AIF under the heading "*Forward-Looking Statements*" above.

DIVIDENDS

The following cash dividends per Common Share were distributed by the Company for each of the three most recently completed financial years:

Dividends	2022	2021	2020
January	—	—	$0.0125
February	—	—	—
March	—	—	—
April	—	—	—
May	—	—	—
June	—	—	—
July	—	—	—
August	—	—	—
September	—	—	—
October	—	—	—
November	—	—	—
December	—	—	—
Total	—	—	**$0.0125**

1. On February 5, 2020, the Company suspended the payment of dividends effective February 2020 in response to significant price volatility for crude products in the Canadian energy sector.

Cash Dividend Policy

The Company is not currently intending to pay any cash dividends on our Common Shares but will review that policy from time to time as circumstances warrant. Razor currently intends to retain future earnings, if any, for future operations, expansion and possible debt repayment or share repurchases. Any decision to declare and pay dividends in the future will be made at the discretion of the Board and will depend on, among other things, results of operations, current and anticipated cash requirements, financial condition, contractual restrictions and financing agreement covenants, and other factors that the Board may deem relevant.

DESCRIPTION OF SHARE CAPITAL

The Company is authorized to issue an unlimited number of Common Shares without nominal or par value and an unlimited number of preferred shares, issuable in series. As of December 31, 2022, an aggregate of 25,275,250 fully paid and non-assessable Common Shares were issued and outstanding, and no preferred shares were issued and outstanding. In addition, 949,600 Razor stock options, 264,000 FutEra stock options and no warrants were issued and outstanding on December 31, 2022.

The holders of the Common Shares are entitled to receive notice of all meetings of Shareholders and to attend and vote the Common Shares at all such meetings. Each Common Share carries with it the right to one vote.

MARKET FOR SECURITIES AND TRADING HISTORY

Following completion of the Arrangement, the Common Shares were listed and posted for trading on the facilities of the TSXV under the symbol "**RZE**" on February 13, 2017. The following table sets forth the market price ranges and the trading volumes of the Common Shares as reported by the TSXV for the periods indicated:

	Price Range ($ per Common Share)		
2022	**High**	**Low**	**Volume**
January	1.05	0.73	1,393,700
February	1.42	0.86	1,664,500
March	4.14	1.60	6,077,500
April	3.60	2.51	2,980,200
May	3.31	2.00	2,986,500
June	3.60	2.12	3,038,200
July	2.69	1.80	1,439,700
August	2.70	1.84	1,532,100
September	2.06	1.18	1,600,800
October	1.95	1.57	879,600
November	2.11	1.56	1,169,200
December	1.71	1.04	1,231,500

DIRECTORS AND OFFICERS

Directors and Officers

The following table sets forth the names and municipalities of residence of the directors and executive officers of the Company as at the date hereof, their respective positions and offices with the Company and date first elected as a director and their principal occupation(s) within the past five years.

Name and Municipality of Residence	Position Presently Held	Director Since	Principal Occupation for Previous Five Years
Doug Bailey Calgary, Alberta, Canada	President, Chief Executive Officer and Director	February 3, 2017	President and Chief Executive Officer of the Company since February 2017. Mr. Bailey also holds the positions of President & CEO and Director of Blade and Executive Director of FutEra.
Frank Muller Calgary, Alberta, Canada	Director, Former Senior Vice President and Chief Operating Officer	February 3, 2017	Retired Professional Geologist since May 2022. Retired Senior Vice President and Chief Operating Officer of the Company from February 2017 to May 2022.
Michael Blair Calgary, Alberta, Canada	Chief Operating Officer	—	Chief Operating Officer of the Company since May 2022. Prior thereto, Mr. Blair was Senior Production Engineer of Sproule Associates Limited from June 2021 to April 2022 and Production Manager of Ventura Resources Inc. from March 2016 to March 2020.
Kevin Braun Calgary, Alberta, Canada	Chief Financial Officer	—	Chief Financial Officer of the Company since February 2017. Mr. Braun also holds the position of Director of FutEra and Blade.
Lisa Mueller Calgary, Alberta, Canada	Vice President, New Ventures and President and CEO of FutEra	—	Vice President, New Ventures of the Company since May 2017. Ms. Mueller also holds the positions of President & CEO of FutEra since October 1, 2021.
Devin Sundstrom Calgary, Alberta, Canada	Vice President, Production	—	Vice President, Production of the Company since February 2017.
Stephen Sych Calgary, Alberta, Canada	Vice President, Operations	—	Vice President, Operations of the Company since February 2017.
Sonny Mottahed (1)(2)(3) Calgary, Alberta, Canada	Director	February 3, 2017	Chief Executive Officer and Managing Partner of Black Spruce Merchant Capital since April 2012.
Sean Phelan(1)(2)(3) Calgary, Alberta, Canada	Director	October 15, 2020	Controller of Interra Energy Services Ltd. since March 2023. Prior thereto, Vice President, Finance of Alberta Environmental Rubber Products from March 2021 to February 2023. Management consultant from February 2020 to February 2021. Vice President, Finance and Administration of Matrix Drilling Fluids Ltd. from May 2004 to April 2020.

Notes:

(1) Member of the Audit Committee.

(2) Member of the Reserves and Environment Committee.

(3) Member of the Corporate Governance and Compensation Committee.

As at the date hereof, the directors and officers of the Company, and their associates and affiliates, as a group, whether beneficial, direct or indirect, own 4,513,302 Common Shares, representing approximately 17.86% of the currently outstanding Common Shares.

The directors listed above will hold office until the next annual meeting of the Company or until their successors are elected or appointed.

Cease Trade Orders and Bankruptcies

No director or executive officer of the Company is, or within ten years prior to the date of this AIF has been, a director, a chief executive officer or a chief financial officer of any company (including the Company), that:

a) was subject to: (i) a cease trade order; (ii) an order similar to a cease trade order; or (iii) 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 (collectively, 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.

No director, executive officer or, to the best of the Company's knowledge, any Shareholder holding a sufficient number of securities of the Company to affect materially control of the Company, is, or within ten years prior to the date of this AIF has been, a director or executive officer of any company (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Personal Bankruptcies

No director or executive officer of the Company or a Shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has, within the past ten years prior to the date of this AIF, become 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 the assets of such person.

Penalties and Sanctions

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

Conflicts of Interest

Certain of the directors and officers of the Company are also directors, officers and/or promoters of other reporting and non-reporting issuers, which may give rise to conflicts of interest. In accordance with corporate laws, directors who have an interest in a contract or a proposed contract with the Company 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 Company. Some of the directors of the Company have other employment or other business or time restrictions placed on them and accordingly, these directors of the Company will only be able to devote part of their time to the affairs of the Company. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA. As of the date hereof, the Company is not aware of any existing or potential material conflicts of interest between the Company and any director or officer of the Company.

EXTERNAL AUDITOR SERVICE FEES

The following table summarizes the fees billed to the Company by its auditors, KPMG LLP (**"KPMG"**), for external audit and other services during the periods indicated:

($000's)	**2022**	**2021**
Audit fees [1]	449,400	341,330
Audit-related fees [2]	—	—
Tax fees [3]	29,211	10,165
All other fees [4]	—	—
	478,611	351,495

Notes:

1) Audit fees were for professional services rendered by KPMG for the audit of the Company's annual financial statements and review of the Company's interim quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements.

2) Audit-related fees are for assurance and related services provided by KPMG that are reasonably related to the performance of the audit of the Company's financial statements and not reported under "Audit fees" above.

3) Tax fees were for tax compliance, tax advice and tax planning.

4) All other fees related to products and services provided by KPMG other than those described as "Audit fees", "Audit-related fees" and "Tax fees".

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

On July 16, 2020, Canadian Natural Resources, and general partnership, by its managing partners Canadian Natural Resources Limited and Canadian Natural Resources Limited (the "**Plaintiffs**") filed a statement of claim commencing Action 2001-08540 (the "**Action**") in the Judicial Centre of Calgary of the Court of Queen's Bench of Alberta against the Company and its Board of Directors. The Plaintiffs allege that the Company paid a dividend from October 2018 through to December 2019 during which time the Company had financial obligations owing to the Plaintiffs. The Plaintiffs seek general damages of $4,576,6345.33, which represents amounts owing to the Plaintiffs at the time the Action was filed. Amounts owing to the Plaintiffs are included in the Company's accounts payable and accrued liabilities at December 31, 2021. During the fourth quarter of 2021, Razor filed a Statement of Defence and a Counterclaim which alleges the joint venture partner over charged the joint account, underpaid revenue, conducted work without authorization and generally mis handled the joint account to the detriment of Razor. There can be no assurance that further financial damages will not occur, however, the Company did not have any amounts related to the Statement of Claim owing to this joint venture partner as at December 31, 2022.

Other than as set forth above, there are no legal proceedings material to the Company to which the Company is a party or of which any of its property is the subject matter, and there are no such proceedings known to the Company to be contemplated. There are no penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the most recently completed financial year, there are no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decisions, and there are no settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

To the best of the Company's knowledge, except as disclosed herein regarding AIMCo's interest in the Amended Term Loan Facility, there are no material interests, direct or indirect, of directors or executive officers of the Company, any Shareholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years of the Company or during the current financial year which has materially affected, or is reasonably expected to materially affect, the Company.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar is Alliance Trust Company at its principal office in Calgary, Alberta.

MATERIAL CONTRACTS

Except as disclosed herein and other than contracts entered into in the ordinary course of business, there have been no material contracts entered into by the Company within the most recently completed financial year, or before the most recently completed financial year that are still in effect.

PROMOTERS

Doug Bailey may be considered to be a promoter of the Company pursuant to applicable securities laws. As at the date hereof, Doug Bailey beneficially owns, directly or indirectly, 1,563,570 Common Shares representing approximately 6.19% of the outstanding Common Shares.

INTERESTS OF EXPERTS

Reserve estimates contained in this Annual Information Form have been prepared by Sproule. As at December 31, 2021, the effective date of those estimates, and as of the date hereof, the principals, directors, officers and associates of Sproule, as a group, owned, directly or indirectly, less than one percent of the outstanding Common Shares.

KPMG LLP, the Company's auditors, are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or any associate or affiliate of the Company.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's information circular for the Company's most recent Shareholder's meeting that involved the election of directors. Additional financial information is contained in the Company's consolidated financial statements and the related management's discussion and analysis for the year ended December 31, 2022.

Additional copies of this AIF and the materials listed in the preceding paragraph are available on the foregoing basis and upon request by contacting the Company at its offices at 800, 500 - 5th Avenue S.W., Calgary, Alberta, T2P 3L5 or by phone at (403) 262-0242.

SCHEDULE A

FORM 51-101F2

REPORT ON RESERVES DATA

BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Razor Energy Corp. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2022, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule	December 31, 2022	Canada				
Total			**Nil**	**234,432**	**Nil**	**234,432**

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with COGEH, 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 report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of Razor Energy Corp. (As of December 31, 2022)".

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 27, 2023

(signed) *"Doug Ashton, P.Eng."*

____

Doug Ashton, P.Eng.
VP, Reservoir Services

(signed) *"Gary Finnis, P.Eng."*

____

Gary Finnis, P.Eng.
Senior Manager, Engineering

SCHEDULE B

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of Razor Energy Corp. (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.

Independent qualified reserves evaluators have evaluated and reviewed the Company’s reserves data. The report of the independent qualified reserves evaluators is presented in the Annual Information Form of the Company for the year ended December 31, 2022.

The Reserves Committee of the Board of Directors of the Company has:

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

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

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

The Reserves Committee of the Board of Directors has reviewed the 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 recommendation of the Reserves Committee, approved:

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

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

President, Chief Executive Officer and Director

(signed) *"Michael Blair"*

Chief Operating Officer

(signed) *"Sean Phelan"*

Director

(signed) *"Sonny Mottahed"*

Director

Dated May 1, 2023