RAZOR ENERGY CORP.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2020

April 14, 2021

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 April 14, 2021 for the financial year ended December 31, 2020.

“**AIMCo**” means Her Majesty the Queen in Right of Alberta by its agent, Alberta Investment Management Corporation.

“**Amended Term Loan Facility**” 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.

“**Kaybob Acquisition**” means the acquisition of certain oil and gas assets located in the Kaybob area of Alberta from an arm’s length public oil and gas company for aggregate consideration of $12.3 million, including customary closing and post-closing reconciliation adjustments.

“**Kaybob Triassic Unit 1 and 2 Working Interest Acquisition**” means series of acquisitions of additional working interest in the Kaybob Triassic Unit 1 and 2 for total cash consideration of $9.6 million, including customary closing and post-closing reconciliation adjustments.

“Little Rock Acquisition” means the acquisition of Little Rock Resources Ltd. (“Little Rock”), which owned certain oil and gas assets located in southern Alberta, for aggregate consideration of $13.2 million, including the issuance of $9.6 million in Common Shares and the assumption of Little Rock’s net debt of $3.6 million.

“**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 19, 2021 and effective December 31, 2020.

"**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, 2020, 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;
- the global public health crises in respect of the outbreak of the novel coronavirus (COVID-19), including volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people;
- 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;
- 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 4300, 888 - 3rd Street S.W., Calgary, Alberta, T2P 5C5.

As at December 31, 2020 the Company has three wholly owned subsidiaries, Blade Energy Services Corp. ("Blade"), FutEra Power Corp. ("FutEra"), and Razor Resources Corp. All subsidiaries are incorporated under the laws of the Province of Alberta.

GENERAL DEVELOPMENT OF THE BUSINESS

Three-Year History

Financial Year Ended December 31, 2018

On January 15, 2018, the Company increased its existing Term Loan Facility by $15.0 million for an amended principal amount of $45.0 million (the "Amended Term Loan Facility"). The Amended Term Loan Facility matures on January 31, 2021 with an interest rate of 10% payable semi-annually. As consideration for the Amended Term Loan Facility, 255,600 Common Shares were issued to AIMCo.

On January 15 and June 20, 2018, the Company acquired additional working interest positions to further consolidate its existing Kaybob Triassic Units 1 & 2 for aggregate cash consideration of $5.0 million, including customary closing and post-closing reconciliation adjustments.

On September 5, 2018, the Company declared a special cash dividend of $0.165 per Common Share payable on October 5, 2018 to Shareholders of record on October 2, 2018.

On October 1, 2018, the Company announced its transition to a dividend paying company and declared its first monthly cash dividend of $0.0125 per Common Share payable on October 31, 2018 to Shareholders of record on October 15, 2018. Monthly dividends were declared and paid in November and December 2018.

Financial Year Ended December 31, 2019

On February 6, 2019, the Company completed a non-monitory asset swap whereby Razor increased its working interest position in its Virginia Hills Unit 1 and completely disposed its working interest in Kaybob Beaverhill Lake Unit 1. This transaction increased the Company's working interest position in Virginia Hills Unit 1 to 100%.

On September 11, 2019, the Company completed the Little Rock Acquisition, pursuant to which the Company acquired certain oil and gas assets located in southern Alberta, for aggregate consideration of $13.2 million, including the issuance of $9.6 million in Common Shares and the assumption of Little Rock's net debt of $3.6 million. This acquisition provided the Company with a second core region in southern Alberta, with significant presence in the Jumpbush, Majorville, Badger, Enchant and Chin Coulee areas.

During 2019, the Company declared and paid a dividend of $0.0125 per Common Share each month, representing total dividends paid of $0.15 per Common Share for the year.

Financial Year Ended December 31, 2020

On January 9, 2020, Razor announced a monthly cash dividend of $0.0125 per share. 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.

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 have 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 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.

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 Blade Energy Services Corp. ("**Blade**") and FutEra Power Corp. ("**FutEra**") 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.

Blade, through the experience of being Razor's primary oilfield service provider, continues attracting skilled and experienced labour and acquire equipment in order to service the broad external market.

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, 2020, the Company had 55 employees (comprised of 30 head office, 11 field operation employees and 14 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, 2020

The reserves data set forth below is based upon an evaluation by Sproule Associates Limited ("**Sproule**") and contained in the Sproule Report dated February 19, 2021. The effective date of this report is December 31, 2020 and was prepared for Razor between December 2020 and February 2021. 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, 2020 and based on the Sproule December 31, 2020 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, 2020

	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	4,940	4,334	193	180	4,126	3,882	1,595	1,304	7,416	6,465
Developed non-producing	2,891	2,580	103	100	784	750	1,343	1,110	4,468	3,915
Undeveloped	1,178	1,097	291	268	445	423	98	92	1,641	1,527
Total Proved	**9,009**	**8,012**	**587**	548	**5,355**	**5,055**	**3,036**	**2,505**	**13,525**	**11,907**
Total Probable	2,637	2,322	144	129	1,377	1,304	783	679	3,793	3,347
Total Proved plus Probable	**11,647**	**10,333**	**731**	676	**6,732**	**6,359**	**3,819**	**3,184**	**17,319**	**15,254**

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, 2020

	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	(109,463)	7,172	26,553	29,075	4.11
Developed Non-Producing	84,169	62,960	49,199	39,730	12.57
Undeveloped	32,005	25,137	19,756	15,568	12.94
Total Proved	**6,712**	**95,269**	**95,508**	**84,372**	**8.02**
Total Probable	86,027	54,611	37,709	27,525	11.27
Total Proved plus Probable	**92,738**	**149,880**	**133,216**	**111,898**	**8.73**

Notes:

(1) Utilizes Sproule's price forecast as of December 31, 2020 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.

	After 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	(109,463)	7,172	26,553	29,075	4.11
Developed Non-producing	83,104	62,340	48,828	39,501	12.47
Undeveloped	24,303	19,585	15,675	12,517	10.27
Total Proved	**(2,056)**	**89,097**	**91,056**	**81,093**	**7.65**
Total Probable	69,460	43,242	29,521	21,397	8.82
Total Proved plus Probable	**67,404**	**132,340**	**120,576**	**102,490**	**7.91**

Notes:

(1) Utilizes Sproule's price forecast as of December 31, 2020 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, 2020

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	763,547	89,370	418,072	40,585	208,809	6,712	8,768	(2,056)
Total Proved Plus Probable	1,004,965	118,284	531,536	52,639	209,768	92,738	25,334	67,404

FUTURE NET REVENUE BY PRODUCT TYPE
(FORECAST PRICES AND COSTS)
AS OF December 31, 2020

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	83,364	7.55
	Heavy Crude Oil including solution gas liquids	11,084	17.38
	Conventional Natural Gas including associate by-products	1,060	4.73
		95,508	
Proved Plus Probable	Light and Medium Crude Oil including solution gas liquids	117,948	8.32
	Heavy Crude Oil including solution gas liquids	13,993	17.74
	Conventional Natural Gas including associate by-products	1,275	4.46
		133,216	

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, 2020, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
(FORECAST PRICES AND COSTS)
AS OF December 31, 2020

Year	WTI Oil ($US/Bbl)	Edmonton Light Sweet Oil ($Cdn/Bbl)	Hardisty Bow River ($Cdn/Bbl)	Natural Gas AECO ($Cdn/MMBTU)	Exchange Rate ($US/$CDN)
Forecast					
2021	46.00	54.55	44.16	2.86	0.77
2022	48.00	57.14	46.80	2.78	0.77
2023	53.00	63.64	53.39	2.69	0.77
2024	54.06	64.91	54.50	2.75	0.77
2025	55.14	66.21	55.59	2.80	0.77
2026	56.24	67.53	56.70	2.86	0.77
2027	57.37	68.88	57.83	2.91	0.77
2028	58.52	70.26	58.99	2.97	0.77
2029	59.69	71.66	60.17	3.03	0.77
2030	60.88	73.10	61.37	3.09	0.77
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, 2020, was $47.62/Bbl for light crude oil, $44.02/Bbl for heavy oil, $16.80/Bbl for NGLs and $1.82/Mcf for natural gas.

	Q4-2020	Q3-2020	Q2-2020	Q1-2020	Q4-2019	Q3-2019	Q2-2019	Q1-2019
Average selling price								
Oil price ($/bbl)	49.53	49.08	30.95	48.08	67.59	64.19	79.71	69.76
NGL price ($/bbl)	22.50	16.74	12.96	16.07	23.82	24.24	34.37	35.89
Gas price ($/mcf)	2.21	1.75	1.47	1.87	1.69	1.01	1.74	2.42
Benchmark prices and foreign exchange rates								
OIL ($/bbl)								
WTI (USD)	42.76	40.93	27.85	46.17	56.94	56.44	59.80	54.83
WTI (CAD)	55.66	54.51	38.42	61.64	75.16	74.54	80.00	72.91
CAD/USD EXCHANGE RATE	0.77	0.75	0.72	0.75	0.76	0.76	0.75	0.75
WTI vs Light Sweet Edmonton Oil differential (CAD/bbl)	(5.53)	(4.74)	(8.70)	(10.30)	(7.19)	(6.22)	(6.16)	(6.57)
NATURAL GAS (CAD/mcf)								
AECO NGX AB-5a	2.65	2.24	2.00	2.04	2.49	0.84	1.02	2.59
AECO NGX AB-7a	2.77	2.16	1.93	2.15	2.36	1.04	1.17	1.98

The Abandonment, Decommissioning and Reclamation (“ADR”) cost, discounted at year-end 2020, was $34.2 million, an increase of $1.7 million from year-end 2019 ($32.5 million). The Inactive Well Cost (“IWC”) discounted at year-end 2020, was $31.4 million, an increase of $2.6 million from year-end 2019 ($28.8 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, 2020 price forecast. These expenditures are expected to occur between 2021 and 2076.

	Discounted at Various Rates			
	0%	**5%**	**10%**	**15%**
Description	M$	M$	M$	M$
Abandonment, decommissioning and reclamation costs (“ADR”)	206,717	67,247	34,184	22,658
Inactive well costs (“IWC”)	49,850	38,831	31,349	26,069
Total	**256,567**	**106,078**	**65,533**	**48,727**

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, 2019 to December 31, 2020, using forecast prices and costs. Key highlights include:

- As a result of lower oil price forecasts year over year, Razor observed a negative impact on the Economic Factors category.
- Technical Revisions were primarily a reserves change removing fuel gas volumes as per COGEH rules.
- Razor acquired additional working interest in the Swan Hills area resulting is an increase in volumes.

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	**10,432**	**555**	**12,893**	**3,122**	**16,258**
Acquisitions	303	-	363	145	508
Dispositions	-	-	-	-	-
Technical Revisions	304	86	(6,002)	432	(178)
Economic Factors	(1,260)	(30)	(564)	(361)	(1,744)
Production	(771)	(24)	(1,335)	(302)	(1,319)
Total Reserves, end of year	**9,009**	**587**	**5,355**	**3,036**	**13,525**

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	**2,893**	**127**	**3,683**	**859**	**4,492**
Acquisitions	76	-	71	37	125
Dispositions	-	-	-	-	-
Technical Revisions	(115)	24	(2,160)	41	(411)
Economic Factors	(217)	(8)	(217)	(153)	(413)
Production	-	-	-	-	-
Total Reserves, end of year	**2,637**	**144**	**1,377**	**783**	**3,793**

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	**13,325**	**682**	**16,575**	**3,981**	**20,750**
Acquisitions	379	-	434	181	633
Dispositions	-	-	-	-	-
Technical Revisions	189	110	(8,162)	473	(589)
Economic Factors	(1,476)	(37)	(780)	(514)	(2,157)
Production	(771)	(24)	(1,335)	(302)	(1,319)
Total Reserves, end of year	**11,647**	**731**	**6,732**	**3,819**	**17,319**

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 Montney formation in Kaybob, two vertical and seven horizontal wells in the Beaverhill Lake formation in Swan Hills, three Mannville horizontal wells in Badger and two Glauconitic horizontal wells in Jumpbush.

An additional five horizontal wells in the Beaverhill Lake formation in Swan Hills were assigned probable undeveloped reserves.

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
2021	12,526	24,580
2022	25,535	25,535
2023	0	0
Thereafter	2,525	2,525
Total Undiscounted	**40,585**	**52,639**
Total Discounted at 10%	**36,009**	**47,826**

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 $40.6 million for proved reserves and $52.6 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
2018	347	1,382	0	0	195	424	53	116	433	1,569
2019	190	1,544	280	280	266	629	4	137	518	2,067
2020	0	1,178	0	291	0	445	0	98	0	1,641

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
2018	122	827	0	0	72	453	18	158	152	1,060
2019	56	830	82	82	78	522	1	162	152	1,160
2020	0	831	0	87	0	158	0	104	0	1,048

As of December 31, 2020, undeveloped reserves represented 12% per cent of total proved reserves and 16% per cent of proved plus probable reserves. Most of the undeveloped reserves are in our Swan Hills asset. There are nine horizontal proved plus probable undeveloped Beaverhill Lake drilling locations in Swan Hills with an additional two vertical wells. There are two vertical wells in the Montney formation in Kaybob. There are five horizontal 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 2021 to 2022. 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, 2020, the assets included 166,240 gross (131,582 net) acres of total land, of which 36,320 gross (31,881 net) acres were booked as undeveloped land. The assets at Swan Hills include 1,335 gross (763 net) wells in total, of which 319 gross (177 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. Field-reported net working interest production from the area for the month ended December 31, 2020 averaged 2,030 boe/d comprised of 62% light oil, 27% NGL's and 11% natural gas.

Kaybob

The Kaybob area is located in west central Alberta approximately 250 km northwest of Edmonton. As at December 31, 2020, 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 230 gross (156 net) wells in total, of which 42 gross (28 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. Field-reported net working interest production from the area for the month ended December 31, 2020 averaged 952 boe/d of which 58% was light oil, 21% NGL's and 21% natural gas.

District South

The District South is an area located in Southern Alberta, approximately 250 km southeast of Calgary. As at December 31, 2020, the assets included 78,190 gross (49,642 net) acres of total land, of which 10,560 gross (5,042 net) were booked as undeveloped land. The assets include 535 gross (419 net) wells in total, of which 183 gross (143 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. Field reported net working interest production from the area for the ending December 31, 2020 was 614 boe/d, made up of 38% oil, 4% NGL's and 58% gas.

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, 2020. 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	242	229	87	75	497	476	75	63	309	291
Non-operated	183	34	32	10	327	72	99	38	249	50
Total	**425**	**263**	**119**	**85**	**824**	**548**	**174**	**101**	**558**	**341**

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, 2020.

	Undeveloped Acres		Developed Acres		Total Acres	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	62,160	41,707	275,310	182,011	337,470	223,718
Total	**62,160**	**41,707**	**275,310**	**182,011**	**337,470**	**223,718**

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 rights to explore, develop and exploit approximately 4,416 net acres of undeveloped land holdings may expire by December 31, 2021. 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 Note 14 of Razor's annual consolidated financial statements and accompanying Managements' Discussion and Analysis for the year ended December 31, 2020 and which can be found on SEDAR at www.sedar.com.

Tax Horizon

For the fiscal year end December 31, 2020, the Company paid no income tax and has approximately $87.9 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, 2020.

Expenditure	**Year Ended December 31, 2020** ($000s)
Property acquisition costs	-
Development costs	1,929
Other	-
Total	**1,929**

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, 2021, 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	1,655	—	495	627	2,365
Kaybob	735	—	840	114	989
District South	113	114	1,044	12	413
Total Proved	**2,503**	**114**	**2,379**	**753**	**3,767**
Probable					
Swan Hills	337	—	7	47	385
Kaybob	15	—	80	7	35
District South	2	13	35	0	21
Total Probable	**354**	**13**	**122**	**54**	**441**
Total Proved plus Probable	**2,857**	**127**	**2,501**	**807**	**4,208**

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:

	2020 Quarter Ended				Year Ended
	Q4	**Q3**	**Q2**	**Q1**	**December 31**
	Dec. 31	**Sept. 30**	**June 30**	**March 31**	**2020**
Average Daily Production[1]					
Light Oil (Bbls/d)	1,815	1,869	1,920	2,308	**1,977**
Heavy Oil (Bbls/d)	208	178	76	334	**199**
Natural gas liquids[2] (Bbls/d)	701	791	865	940	**824**
Conventional natural gas (Mcf/d)	5,165	4,411	5,528	3,676	**4,695**
Combined (BOE/d)	3,585	3,573	3,782	4,195	**3,783**
Average Daily Sales Volumes[1]					
Light Oil (Bbls/d)	1,814	1,930	1,876	2,327	**1,986**
Heavy Oil (Bbls/d)	210	256	95	210	**193**
Natural gas liquids[2] (Bbls/d)	701	791	865	940	**824**
Conventional natural gas (Mcf/d)	4,461	3,362	4,287	3,969	**3,767**
Combined (BOE/d)	3,469	3,537	3,550	3,969	**3,631**
Average Price Received					
Light Oil ($/Bbl)	51.62	52.28	37.72	48.84	**47.62**
Heavy Oil (Bbls/d)	48.99	69.43	41.80	27.70	**44.02**
Natural gas liquids ($/Bbl)	22.50	16.74	12.96	16.09	**16.80**
Conventional natural gas ($/Mcf)	2.21	1.75	1.47	1.87	**1.82**
Combined ($/BOE)	36.56	36.68	25.10	34.32	**33.12**
Royalties Paid[3]					
Light Oil ($/Bbl)	6.25	3.42	2.13	7.83	**5.04**
Heavy Oil (Bbls/d)	1.17	0.69	0.11	0.99	**0.98**
Natural gas liquids ($/Bbl)	7.21	5.20	2.75	11.03	**6.65**
Conventional natural gas ($/Mcf)	(0.14)	(1.20)	0.55	(3.09)	**(0.76)**
Combined ($/BOE)	4.43	1.44	2.53	4.15	**3.19**
Production Costs[3]					
Light Oil ($/Bbl)	29.82	22.53	19.90	34.25	**26.72**
Heavy Oil (Bbls/d)	90.03	58.27	142.28	107.35	**90.50**
Natural gas liquids ($/Bbl)	29.82	22.53	19.90	34.25	**26.72**
Conventional natural gas ($/Mcf)	4.97	3.76	3.32	5.71	**4.45**
Combined ($/BOE)	33.38	25.58	23.07	36.90	**29.93**
Netback Received[3][4]					
Light Oil ($/Bbl)	15.55	26.33	15.69	6.75	**15.85**
Heavy Oil (Bbls/d)	(42.20)	10.47	(101.58)	(80.65)	**(47.46)**
Natural gas liquids ($/Bbl)	(14.50)	(10.99)	(9.74)	(29.20)	**(16.57)**
Conventional natural gas ($/Mcf)	(2.62)	(0.81)	(2.39)	(0.75)	**(1.87)**
Combined ($/BOE)	(1.25)	9.60	(0.50)	(6.74)	**0.00**

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, 2020 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	1,488	1,367	678	2,39
Kaybob	488	1,182	120	805
District South	199	2,146	26	583
Total	2,176	4,695	824	3,783

The average production for the year ended December 31, 2020 was 79% liquids; and for the year ended December 31, 2020, 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

Producers of crude oil are entitled to negotiate sales contracts directly with purchasers, with the result that the market determines the price of crude oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance, and contractual terms of sale.

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

Natural Gas

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

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

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the 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.

Under the Canadian constitution, inter-provincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, has faced significant delays due to permitting in the United States. However, Minnesota regulators approved the final required permit for the project in November 2020. Certain segments of the Line 3 Replacement in North Dakota and Wisconsin are currently in operation and the Canadian portion of the replaced pipeline began commercial operation in December 2019. Construction of the Line 3 Replacement in Minnesota began in early December 2020; Enbridge expects the line to be in service in the fourth quarter of 2021.

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

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

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

Marine Tankers

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 Alberta have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport for their natural gas production out of Western Canada, may be able to access more markets and obtain better pricing. Companies without firm access to transportation in Western Canada may be forced to accept spot pricing for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. The Temporary Service Protocol ended on October 2020 and the CER rejected a request to extend it further in February 2021. However, due to recent expansions on the NGTL system, the Temporary Service Protocol was not required during the summer 2020 maintenance season, and with current market conditions and recent approved expansions to the NGTL system, capacity has improved.

While a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project. Pre-construction activities began in November 2018, with a planned completion target of 2025. 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").

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, however, both partners are looking to sell some or all of their interest in the project.

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

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

The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence but Pieridae Energy Ltd. has delayed its final investment decision until mid-2021.

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

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline 36 system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

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

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The regulatory hearing process is currently underway and a final decision from the CER is not expected until mid-2021. If Enbridge receives CER approval, it intends to hold the open season by the end of 2021.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, as amended effective October 1, 2019, the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 bbls/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

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

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen. As of December 2020, monthly oil production limits are no longer in effect. However, the Curtailment Rules, which were set to be repealed on December 31, 2020 have been extended such that the Government of Alberta retains the ability to impose production limits if needed. The Company is not subject to a curtailment order.

GOVERNMENT REGULATIONS

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/USMCA

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. Decisions about a prospective carbon market and emissions cuts will be discussed at the next climate conference, scheduled to take place in November 2021.

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 its recent Speech from the Throne (also referred to as the "Throne Speech"; discussed in greater detail below) that it may implement policy changes to exceed this target. Specific details have not yet been announced.

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 ~~but will not come~~ 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.

In November 2016, the federal government announced that it would commence development of a performance-based clean fuel standard ("**CFS**") that would incent the use of a broad range of low carbon fuels, energy sources and technologies. The objective of the CFS is to achieve 30 Mt of annual reductions in GHG emissions by 2030, as part of efforts to achieve Canada's commitments under the Paris Agreement. The proposed regulations to implement CFS are not anticipated to be enacted until December 2022.

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

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

Alberta

In June 2019, the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $30/tonne of CO_2e and will increase to $40/tonne on April 1, 2021. In December 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous Carbon Competitiveness Incentives Regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO_2e 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 43 considerations while adjudicative functions fall to independent commissioners. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

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

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 Programs

In Alberta, the AER administers the *Liability Management Rating Program* (the "AB **LMR Program**"), which is currently undergoing changes, including a name change to the *Liability Management Framework* (the **"AB LMF"**), as part of the Liability Management Rating Assessment Process. The LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. It consists of three distinct programs: the *Oilfield Waste Liability Program* (the **"AB OWL Program"**), the *Large Facility Liability Management Program* (the **"AB LFP"**), and the *Licensee Liability Rating Program* (the "**AB LLR Program**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the licensee, must reduce its liabilities or provide the AER with a security deposit. Failure to do so may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating (**"LMR"**).

The OGCA establishes an orphan well fund (the "**Orphan Well Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Well Fund is funded by licensees in the LLR Program through a levy administered by the AER. The LLR Program is designed to minimize the risk to the Orphan Well Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and upon the submission of a license transfer application, and failure to post the required security deposit may result in the initiation of enforcement actions by the AER.

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

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in *Redwater Energy Corporation* (Re) (**"Redwater"**), holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In Response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. The AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

The AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20 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 list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76 percent of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale.

Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets.

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 and OPEC actions. 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, 2020, the Company has a working capital deficit of $72.3 million, of which only $1.1 million is comprised of cash and cash equivalents. Further, at December 31, 2020, the Company has contractual repayments of $79.5 million due in less than one year. The Company is also not in compliance with respect to the adjusted net-debt-to-adjusted cash flow ratio, the minimum working capital ratio and with one of its non-financial covenants in the Amended Term Loan Facility at December 31, 2020 and therefore has an event of default at December 31, 2020. As a result, *Alberta Investment Management Corporation* ("**AIMCo**") has the right to demand repayment of the Amended Term Loan Facility at any time (note 9). The Company also has cross default provisions in certain equipment loans and leases, which are in default as a result of the AIMCo default, and as a result has classified these loans and leases as potentially due on demand current liabilities at December 31 2020 (notes 9 and 10).

Subsequent to December 31, 2020, the Company renewed the *Amended Term Facility* with AIMCo (the "**AIMCo Term Loan**"). There were no additional proceeds received from the AIMCo Term Loan only and extension of the maturity date to January 31, 2024. In addition, the Company entered into a new term loan with Arena Investors, LP ("the Arena Term Loan") to provide additional liquidity of US$11.0 million (CAD$14.0 million) which can only be utilized for specific purposes and requires monthly repayments commencing April 1, 2021. See note 22.

Although, the extension of the AIMCo Term Loan resulted in a reduction to the working capital deficit by virtue of the AIMCo Term Loan being reclassified to long-term, there remains a considerable working capital deficiency largely comprised of accounts payable. The Company anticipates funding the remaining working capital deficit and contractual repayments with a combination of cash from operations, other new debt or equity financings. The operational and commodity price challenges that impacted revenue, production and operating costs in 2020, are anticipated to be somewhat mitigated in 2021 as the Company utilizes funds from the Arena Loan to reactivate wells in order to increase production, which is not without risk. While forecasted prices and operating cashflows are expected to improve in 2021, a material uncertainty remains as to whether the Company can generate sufficient positive cash flow from operations to meet all of its obligations as they come due. Further, no assurance can be provided, that the service providers and other lenders and lessors will not demand repayment of the accounts payable and other loans and leases prior to maturity, or that waivers can be obtained with respect to the other loans and leases.

Due to the conditions noted above there remains a material uncertainty surrounding the Company's ability to generate adequate cash flow from operations and to obtain the necessary waivers from the other lenders and lessors for the covenant violations to enable the Company to address contractual payment obligations. These material uncertainties 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 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 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 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.

Public Health Crises

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide, including the COVID-19 pandemic, Middle East Respiratory Syndrome, Severe Acute Respiratory Syndrome, H1N1 influenza virus, avian flu or any other similar illnesses could have an adverse impact on the Company's results, business, financial condition or liquidity.

In December 2019, COVID-19 was reported to have surfaced in Wuhan, China. On January 30, 2020, the World Health Organization declared the outbreak a global health emergency and on March 11, 2020, the World Health Organization declared the outbreak of a strain of novel coronavirus disease, COVID-19, a global pandemic. The COVID-19 pandemic has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. Unexpected developments in financial markets, regulatory environments, or consumer behaviour may also have adverse impacts on the Company's results, business, financial condition or liquidity, for a substantial period of time.

The Company's business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, be adversely impacted as a result of the pandemic and/or decline in commodity prices as a result of:

- the shut-down of facilities or the delay or suspension of work on capital projects due to workforce disruption or labour shortages caused by workers becoming infected with COVID-19, or government or health authority mandated restrictions on travel by workers or closure of facilities or worksites;
- suppliers and third-party vendors experiencing similar workforce disruption or being ordered to cease operations;
- reduced cash flows resulting in less funds from operations being available to fund capital expenditure budgets;
- reduced commodity prices resulting in a reduction in the volumes and value of reserves;
- crude oil storage constraints resulting in the curtailment or shutting in of production;
- counterparties being unable to fulfill their contractual obligations on a timely basis or at all;
- the inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate; and
- the ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

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

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

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 these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines 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 took steps to cancel the presidential permit that had allowed the Keystone XL Pipeline to operate across Canadian and American borders. It is unclear if challenges to the revocation of the permit will be successful and what the direct impact of the loss of permit will be on the Company.

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**"), 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 – Public Health Crisis*", 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 newly inaugurated Biden administration in the U.S. has indicated that it will roll-back certain policies of the former administration and has taken action to cancel TC Energy Corporation's Keystone 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 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry. See "*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 – Regulatory Authorities and Environmental Regulation – 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.

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 becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Company's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that the Company must post.

As a result of the Supreme Court of Canada's January 2019 decision in the Redwater case, a trustee in bankruptcy is not permitted to renounce uneconomic oil and gas assets and leave these assets to be remediated by the Orphan Well Fund, thereby avoiding the environmental liabilities of the estate it is administering. Accordingly, the AER may now use Alberta's provincial legislative scheme to prevent the repudiation or renunciation of an insolvent company's assets by a trustee and require the trustee to satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors. In July 2020, the Government of Alberta announced the AB LMR Program will be replaced by the AB LMF. This new AB LMF may impact the Company's ability to transfer its licences, approvals or permits in the course of a divestment and may result in increased costs and delays or require changes to or abandonment of projects and transactions. Lenders may reduce the availability of credit to oil and gas issuers that utilize secured loans, thereby negatively affecting the financial capacity of such issuers, including potential partners and counterparties of the Company. Lenders also may generally increase their scrutiny of oil and gas assets held by producers, including the Company, and the associated A&R liabilities in determining whether to provide credit, may require borrowers to adhere to more stringent A&R-related operational covenants, and may increase the cost of providing credit.

The Supreme Court decision in Redwater also could make the transfer of oil and gas assets from insolvent parties more challenging if a trustee in bankruptcy is unable to separate economic assets from uneconomic assets within the insolvent party's estate in order to facilitate a sale process. The result could be additional liabilities being placed upon the Orphan Well Fund. The Orphan Well Fund may seek funding for such liabilities from industry participants, including the Company, through an increase in its annual levy, further changes to regulations, or other means. While the impact on the Company of any legislative, regulatory or policy decisions as a result of the Redwater decision cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact the Company and materially and adversely affect, among other things, the Company's business, financial condition, results of operations and cash flow.

There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See "*Industry Conditions – Liability Management Rating Programs*".

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.

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.

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.

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.

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

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. 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 would 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.

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 social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, 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	2020	2019	2018
January	$0.0125	$0.0125	—
February	—	$0.0125	—
March	—	$0.0125	—
April	—	$0.0125	—
May	—	$0.0125	—
June	—	$0.0125	—
July	—	$0.0125	—
August	—	$0.0125	—
September	—	$0.0125	—
October[1]	—	$0.0125	$0.1650
	—	—	$0.0125
November	—	$0.0125	$0.0125
December	—	$0.0125	$0.0125
Total	**$0.0125**	**$0.1500**	**$0.2025**

1. On September 5, 2018, the Company declared a special cash dividend of $0.1650 per Common Share payable on October 5, 2018 to Shareholders of record on October 2, 2018. Subsequent to the special cash dividend, Razor declared a monthly cash dividend of $0.0125 per Common Share starting in October 2018. 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

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.

We do not currently anticipate paying 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, 2020, an aggregate of 21,064,466 Common Shares were issued and outstanding. As at the date hereof, there are 21,064,466 fully paid and non-assessable Common Shares issued and outstanding. In addition, there are no warrants or stock options outstanding as at the date hereof.

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.

On September 20, 2019, the TSXV approved the Company's application for a renewed Normal Course Issuer Bid (the "NCIB") to repurchase up to 1,039,148 of its Common Shares, representing 5% of the outstanding Common Shares at September 20, 2019, over a 12-month period commencing September 23, 2019 and ending no later than September 22, 2020.

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)		
2020	**High**	**Low**	**Volume**
January	1.00	0.77	452,084
February	0.80	0.36	1,015,451
March	0.45	0.08	1,109,066
April	0.34	0.10	1,237,554
May	0.26	0.16	507,525
June	0.21	0.12	318,644
July	0.15	0.11	176,825
August	0.20	0.13	209,246
September	0.16	0.11	124,790
October	0.12	0.10	173,066
November	0.45	0.09	944,103
December	0.43	0.22	1,682,382

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. Prior thereto, Mr. Bailey was President and Chief Executive Officer of Razor Private from November 2016 to January 2017, President and Chief Executive Officer of Striker Exploration Corp. ("Striker") from June 2014 to July 2016, and the Chief Financial Officer of Hyperion Exploration Corp. from July 2010 to December 2013.
Frank Muller Calgary, Alberta, Canada	Senior Vice President, Chief Operating Officer and Director	February 3, 2017	Executive Vice President and Chief Operating Officer of the Company since February 2017. Prior thereto, Mr. Muller was Vice President and Chief Operating Officer of Razor Private from November 2016 to January 2017 and Vice President, Exploration and Chief Operating Officer of Striker from June 2014 to June 2016. Mr. Muller was a geological consultant for various oil and gas companies from November 2012 to April 2014. Prior thereto, Mr. Muller was a co-founder and Senior Vice President of WestFire Energy Ltd. from 2007 to 2012.
Kevin Braun Calgary, Alberta, Canada	Chief Financial Officer	—	Chief Financial Officer of the Company since February 2017. Prior thereto, Mr. Braun was Chief Financial Officer of Razor Private in January 2017, the Controller of Brion Energy Corporation from June 2016 to January 2017 and the Controller of Athabasca Oil Corporation from October 2009 to March 2016.
Lisa Mueller Calgary, Alberta, Canada	Vice President, New Ventures	—	Vice President, New Ventures of the Company since May 2017. Prior thereto, Ms. Mueller was President and CEO of Epoch Energy Development from June 2016 to May 2017, and Senior Business Development Manager at Shell from November 2013 to September 2015, and Continuous Improvement Manager for Heavy Oil at Shell from September 2012 to November 2013.
Devin Sundstrom Calgary, Alberta, Canada	Vice President, Production	—	Vice President, Production of the Company since February 2017. Prior thereto, Mr. Sundstrom was Vice President, Production of Razor Private in January 2017, Vice President, Production at Long Run Exploration Ltd. from October 2012 to November 2016 and Vice President, Production at Guide Exploration Ltd. from November 2011 to October 2012.
Stephen Sych Calgary, Alberta, Canada	Vice President, Operations	—	Vice President, Operations of the Company since February 2017. Prior thereto, Mr. Sych was Vice President, Operations of Razor Private from December 2016 to January 2017 and Production Manager of Arsenal Energy Inc. from June 2010 to December 2016.
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. Prior thereto, Mr. Mottahed was the Managing Director, Investment Banking & Head of International Oil & Gas at Raymond James Ltd. from May 2008 to March 2012.
Sean Phelan(1)(2)(3) Calgary, Alberta, Canada	Director	October 15, 2020	Vice President, Finance of Alberta Environmental Rubber Products since March 2021. 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 5,128,912 Common Shares, representing approximately 24.35% 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)	**2020**	**2019**
Audit fees [1]	257,870	222,000
Audit-related fees [2]	16,050	20,000
Tax fees [3]	18,197	2,600
All other fees [4]	—	—
	292,117	244,600

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 March 20, 2017, Malibu Energy Ltd., Topanga Resources Ltd. and North Shore Petroleum Ltd. (the "**Plaintiffs**") filed a statement of claim commencing Action 1701-01476 in the Judicial Centre of Calgary of the Court of Queen's Bench of Alberta against the Company and its Chief Executive Officer (the "**Razor Defendants**") and others. As against the Razor Defendants, the Plaintiffs allege, in essence, that the Razor Defendants were provided with confidential information by certain other defendants about certain petroleum and natural gas assets that a vendor had agreed (subject to certain conditions) to sell to the Plaintiffs. The Plaintiffs claim, jointly and severally against all of the defendants, $165,290,000 in damages, $540,000 in punitive damages, an interlocutory and permanent injunction restraining Razor from acquiring the assets, interest and costs.

On March 28, 2017, the Razor Defendants filed a statement of defence in which they vigorously denied every allegation made against them. On April 21, 2017, the Plaintiffs discontinued their claim against the Company's Chief Executive Officer.

On July 17, 2020, a confidential settlement was reached between the parties of this litigation. Razor determined that it was in the best interest of the Company's resources of time and money to settle the claim, even though the Company's opinion remains that the claim is more likely without merit than not. Also see "*Risk Factors - Legal Proceedings*".

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 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, 2020. There can be no assurance that further financial damages will not occur, however, with the improved commodity price outlook, the Company anticipates amounts owing to the Plaintiffs will be reduced throughout 2021.

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, 1,452,261 Common Shares representing approximately 6.89% 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, 2020, 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, 2020.

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, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the 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, 2020, 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, 2020	Canada				
Total			**Nil**	**133,216**	**Nil**	**133,216**

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, 2020)".

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 19, 2021

Original Signed by Liam O'Brien, P.Eng.

____

Liam O'Brien, P.Eng.
Petroleum Engineer

Original Signed by Steven J. Golko, P.Eng.

____

Steven J. Golko, P.Eng.
Senior VP, Consulting Services

Original Signed by Ian Kirkland, P.Geol.

____

Ian Kirkland, M.Sc., P.Geol.
Senior Geologist

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, 2020.

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) *"Frank Muller"*

Senior Vice President, Chief Operating Officer and Director

(signed) *"Sean Phelan"*

Director

(signed) *"Sonny Mottahed"*

Director

Dated April 14, 2021